NEW ISSUE — BOOK-ENTRY ONLY

Series 2010-A Bonds and Series 2010-B 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 2010-A Bonds and Series 2010-B Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act") and, Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code"). In the further opinion of Special Tax Counsel, interest on the Series 2010-A Bonds and Series 2010-B Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes. Special Tax Counsel expresses no opinion as to whether some or all interest on the Series 2010-A Bonds and Series 2010-B Bonds is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income. See "TAX MATTERS" herein.

Series 2010-C (Taxable) Build America Bonds: In the opinion of Special Tax Counsel, interest on the Series 2010-C (Taxable) Build America Bonds is not excluded from gross income for federal income tax purposes pursuant to Title XIII of the 1986 Act, Section 103 of the 1954 Code or Section 103 of the Internal Revenue Code of 1986. See "TAX MATTERS" herein.

$473,585,000
ENERGY NORTHWEST

$71,150,000 Project 1 Electric Revenue Refunding Bonds, Series 2010-A
$279,980,000 Project 3 Electric Revenue Refunding Bonds, Series 2010-A

$815,000 Project 1 Electric Revenue Refunding Bonds, Series 2010-B
$16,005,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2010-B
$29,865,000 Project 3 Electric Revenue Refunding Bonds, Series 2010-B

$75,770,000 Columbia Generating Station Electric Revenue Bonds, Series 2010-C
(Taxable Build America Bonds)

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

The Series 2010-A Bonds and the Series 2010-B Bonds are being issued for the purpose of refunding certain Electric Revenue Bonds heretofore issued by Energy Northwest, as more fully described herein. The Series 2010-C (Taxable) Build America Bonds are being issued to finance a portion of the costs of certain capital improvements to the Columbia Generating Station, as more fully described herein. See "PURPOSE OF ISSUANCE" herein.

The Series 2010-A Bonds, Series 2010-B Bonds and Series 2010-C (Taxable) Build America Bonds (collectively, the "2010 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 2010 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 2010 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 2010 Bonds. Principal of the 2010 Bonds is payable at the designated office of The Bank of New York Mellon Trust Company, N.A., Seattle, Washington, as Trustee for the 2010 Bonds. Interest on the 2010 Bonds is payable semiannually on January 1 and July 1 of each year, commencing July 1, 2010, by check or draft of the Trustee. As long as Cede & Co. is the Registered Owner as nominee of DTC, payments on the 2010 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 2010 BONDS – GENERAL – Book-Entry System; Transferability and Registration" and Appendix I - "BOOK-ENTRY SYSTEM" herein.

Certain of the 2010 Bonds are subject to redemption prior to maturity as set forth herein. See "DESCRIPTION OF THE 2010 BONDS - REDEMPTION" *herein.*

The 2010 Bonds are special revenue obligations of Energy Northwest, payable solely from the sources described herein, including amounts derived pursuant to Net Billing Agreements with the United States of America, Department of Energy, acting by and through the Administrator of the

Bonneville Power Administration

("Bonneville") from net billing credits and from cash payments from the Bonneville Fund, as described herein. Bonneville's obligations under the Net Billing Agreements are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America. The 2010 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 2010 Bonds is payable solely from the revenues of the Project related to such Series. See "SECURITY FOR THE NET BILLED BONDS" and Appendix A - "THE BONNEVILLE POWER ADMINISTRATION" herein.

MATURITY SCHEDULE — See Inside Cover Pages

The 2010 Bonds are offered when, as, and if issued and received by the Underwriters, subject to the approval of legality by Foster Pepper PLLC, Seattle, Washington, Bond Counsel to Energy Northwest, and to certain other conditions. Certain tax matters will be passed upon by Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel to Bonneville. Certain legal matters will be passed upon for Energy Northwest by its General Counsel and for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP. Certain legal matters will be passed upon for the Underwriters by Fulbright & Jaworski L.L.P., New York, New York, Counsel to the Underwriters. It is expected that the Series 2010-A Bonds and the Series 2010-C (Taxable) Build America Bonds will be available for delivery through the facilities of DTC on or about March 11, 2010. The Series 2010-B Bonds will be available for delivery through the facilities of DTC on or about April 6, 2010.

Goldman, Sachs & Co. **Citi** **J.P. Morgan**
Prager, Sealy & Co., LLC **BofA Merrill Lynch**

February 25, 2010

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES, YIELDS AND PRICES

THE SERIES 2010-A BONDS

$71,150,000 Project 1 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2011	$ 7,615,000	2.00%	0.48%	29270CVG7
2012	2,885,000	2.50	0.83	29270CVH5
2012	2,080,000	3.00	0.83	29270CVP7
2012	3,765,000	5.00	0.83	29270CVV4
2013	2,265,000	3.00	1.11	29270CVJ1
2013	2,990,000	4.00	1.11	29270CVQ5
2013	3,870,000	5.00	1.11	29270CVW2
2014	1,000,000	3.00	1.51	29270CVK8
2014	3,115,000	4.00	1.51	29270CVR3
2014	5,420,000	5.00	1.51	29270CVX0
2015	3,750,000	3.00	1.96	29270CVL6
2015	6,320,000	4.00	1.96	29270CVS1
2016	1,300,000	3.00	2.35	29270CVM4
2016	13,795,000	4.00	2.35	29270CVT9
2017	2,725,000	3.00	2.66	29270CVN2
2017	8,255,000	4.00	2.66	29270CVU6

$279,980,000 Project 3 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2016	$ 16,025,000	5.00%	2.35%	29270CVY8
2017	109,710,000	5.00	2.66	29270CVZ5
2018	154,245,000	5.00	2.94	29270CWA9

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES, YIELDS AND PRICES

THE SERIES 2010-B BONDS

$815,000 Project 1 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2011	$ 815,000	2.00%	0.48%	29270CWB7

$16,005,000 Columbia Generating Station Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Price	CUSIP*
2020	$ 3,005,000	3.75%	100%	29270CWC5
2021	3,095,000	3.875	100	29270CWD3
2022	3,195,000	4.00	100	29270CWE1
2023	3,300,000	4.125	100	29270CWF8
2024	3,410,000	4.25	100	29270CWG6

$29,865,000 Project 3 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2016	$ 29,865,000	5.00%	2.35%	29270CWH4

THE SERIES 2010-C (TAXABLE) BUILD AMERICA BONDS

$75,770,000 Columbia Generating Station Electric Revenue Bonds (Taxable Build America Bonds)

Year (July 1)	Amount	Interest Rate	Price	CUSIP*
2020	$ 14,215,000	4.524%	100%	29270CVB8
2021	14,660,000	4.674	100	29270CVC6
2022	15,125,000	4.824	100	29270CVD4
2023	15,620,000	4.974	100	29270CVE2
2024	16,150,000	5.124	100	29270CVF9

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

Executive Board Members

Sid W. Morrison, Chairman
Tom Casey, Vice Chairman
Kathleen Vaughn, Secretary
Bill Gordon, Assistant Secretary
Edward E. Coates
K.C. Golden
Dan G. Gunkel
Jack Janda
Lawrence Kenney
David Remington
Tim Sheldon

Administrative Staff

Chief Executive Officer	Joseph V. Parrish
Vice President, Nuclear Generation and Chief Nuclear Officer	W. Scott Oxenford
Vice President, Technical Services	Sudesh K. Gambhir
Vice President, Operational Support	Dale K. Atkinson
Vice President, Energy/Business Services	John W. Baker
Vice President, Corporate Services/General Counsel/Chief Financial Officer	Albert E. Mouncer

Financial Advisor
Public Financial Management, Inc.

Bond Counsel
Foster Pepper PLLC

Trustee for the 2010 Bonds
The Bank of New York Mellon 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
Acting Deputy Administrator	Allen Burns
Chief Operating Officer	Anita J. Decker
Executive Vice President and General Counsel	Randy A. Roach
Executive Vice President and Chief Financial Officer	David J. Armstrong

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

No dealer, broker, salesman or other person has been authorized by Energy Northwest or by the Underwriters to give any information or to make any representations, other than as contained in this Official Statement, and, if given or made, such other information or representations must not be relied upon as having been authorized by Energy Northwest or the Underwriters. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy by, nor shall there be any sale of the 2010 Bonds to, any person in any jurisdiction in which such offer, solicitation, or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction.

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

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

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

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

IN CONNECTION WITH THE OFFERING OF THE 2010 BONDS, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS THAT STABILIZE OR MAINTAIN THE MARKET PRICE OF SUCH 2010 BONDS AT LEVELS ABOVE THAT WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

TABLE OF CONTENTS

	Page
INTRODUCTION	1
Energy Northwest	2
The Bonneville Power Administration	2
The 2010 Bonds	3
Net Billing Agreements	3
DESCRIPTION OF THE 2010 BONDS	4
General	4
Designation of Series 2010-C (Taxable) Build America Bonds as “Build America Bonds”	5
Redemption	5
Defeasance	7
PURPOSE OF ISSUANCE	8
Refunding Bonds	8
New Money Bonds	8
SOURCES AND USES OF FUNDS	9
SECURITY FOR THE NET BILLED BONDS	9
Pledge Of Revenues And Priority	9
Events Of Default And Remedies	11
Limitations On Remedies	12
No Reserve Account	12
Additional Indebtedness	12
Net Billing And Related Agreements	13
The Bonneville Fund	16
ENERGY NORTHWEST	18
General	18
Energy Northwest Indebtedness	18
Organizational Structure	19
Executive Board	20
Management	20
Employees	20
Investment Policy	20
The Columbia Generating Station	21
Packwood Lake Hydroelectric Project	25
Nine Canyon Wind Project	26
Project 1	26
Project 3	26
Projects 4 and 5	26
Energy/Business Services	26
Future Resources	27
Net Billed Projects Litigation And Claims	27
LEGAL MATTERS	27
TAX MATTERS	28
Series 2010-A Bonds and Series 2010-B Bonds	28
Series 2010-C (Taxable) Build America Bonds	29
Circular 230 Disclaimer	29
ERISA CONSIDERATION	30
RATINGS	30
UNDERWRITING	30
CONTINUING DISCLOSURE	30
INITIATIVE AND REFERENDUM	31
MISCELLANEOUS	31

APPENDICES

Appendix A	—	THE BONNEVILLE POWER ADMINISTRATION
Appendix B-1	—	FEDERAL SYSTEM AUDITED FINANCIAL STATEMENTS FOR THE YEARS ENDED SEPTEMBER 30, 2009 AND 2008
Appendix B-2	—	FEDERAL SYSTEM UNAUDITED REPORT FOR THE THREE MONTHS ENDED DECEMBER 31, 2009
Appendix C	—	AUDITED FINANCIAL STATEMENTS OF ENERGY NORTHWEST PROJECTS FOR THE YEAR ENDED JUNE 30, 2009
Appendix D-1	—	PROPOSED FORM OF OPINIONS OF BOND COUNSEL
Appendix D-2	—	PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL
Appendix E-1	—	PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE SERIES 2010-A BONDS AND SERIES 2010-C (TAXABLE) BUILD AMERICA BONDS
Appendix E-2	—	PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE SERIES 2010-B BONDS
Appendix F	—	ENERGY NORTHWEST PARTICIPANT UTILITY SHARE OF FISCAL YEAR 2010 BUDGETS
Appendix G	—	SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS
Appendix H-1	—	SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS
Appendix H-2	—	SUMMARY OF CERTAIN PROVISIONS OF THE PRIOR LIEN RESOLUTIONS
Appendix I	—	BOOK-ENTRY SYSTEM
Appendix J	—	SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENTS

[THIS PAGE INTENTIONALLY LEFT BLANK]

OFFICIAL STATEMENT

$473,585,000

ENERGY NORTHWEST

$71,150,000 Project 1 Electric Revenue Refunding Bonds, Series 2010-A
$279,980,000 Project 3 Electric Revenue Refunding Bonds, Series 2010-A

$815,000 Project 1 Electric Revenue Refunding Bonds, Series 2010-B
$16,005,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2010-B
$29,865,000 Project 3 Electric Revenue Refunding Bonds, Series 2010-B

$75,770,000 Columbia Generating Station Electric Revenue Bonds, Series 2010-C
(Taxable Build America Bonds)

INTRODUCTION

Energy Northwest furnishes this Official Statement, which includes the cover page and inside cover pages hereof and the appendices hereto, in connection with the sale of the 2010 Bonds (hereinafter defined). This Introduction is not intended to provide all information material to a prospective purchaser of the 2010 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, proposes to issue $71,150,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2010-A (the "Project 1 2010-A Bonds"), $279,980,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2010-A (the "Project 3 2010-A Bonds," and, together with the Project 1 2010-A Bonds, the "Series 2010-A Bonds"), $815,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2010-B (the "Project 1 2010-B Bonds"), $16,005,000 aggregate principal amount of Columbia Generating Station Electric Revenue Refunding Bonds, Series 2010-B (the "Columbia 2010-B Bonds"), $29,865,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2010-B (the "Project 3 2010-B Bonds," and, together with the Project 1 2010-B Bonds and the Columbia 2010-B Bonds, the "Series 2010-B Bonds") and $75,770,000 aggregate principal amount of Columbia Generating Station Electric Revenue Bonds, Series 2010-C (Taxable Build America Bonds) (the "Series 2010-C (Taxable) Build America Bonds"). The Series 2010-A Bonds, Series 2010-B Bonds and Series 2010-C (Taxable) Build America Bonds are collectively referred to herein as the "2010 Bonds."

The Project 1 2010-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 the Project 1 Electric Revenue Bond Resolution. The Project 1 2010-B Bonds (together with the Project 1 2010-A Bonds, the "Project 1 2010 Bonds") are being issued pursuant to the Act and the Project 1 Electric Revenue Bond Resolution for the purpose of refunding certain indebtedness of Energy Northwest, including certain other indebtedness currently outstanding under the Project 1 Electric Revenue Bond Resolution. In addition, Energy Northwest has indebtedness currently outstanding under Resolution No. 769, adopted on September 18, 1975 (as amended and supplemented, the "Project 1 Prior Lien Resolution"). 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 2010-B 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 under the Columbia Electric Revenue Bond Resolution. The Series 2010-C (Taxable) Build America Bonds (together with the Columbia 2010-B Bonds, the "Columbia 2010 Bonds") are being issued pursuant to the Act and the Columbia Electric Revenue Bond Resolution for the purpose of providing funds for a portion of the costs planned to be incurred during fiscal year 2011 for certain capital improvements to the Columbia Generating Station. In addition, Energy Northwest has indebtedness currently outstanding under Resolution No. 640, adopted on June 26, 1973 (as amended and supplemented, the "Columbia Prior Lien Resolution"). 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 2010-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 the Project 3 Electric Revenue Bond Resolution. The Project 3 2010-B Bonds (together with the Project 3 2010-A Bonds, the "Project 3 2010 Bonds") are being issued pursuant to the Act and the Project 3 Electric Revenue Bond Resolution for the purpose of refunding certain indebtedness of Energy Northwest, including certain other indebtedness currently outstanding under the Project 3 Electric Revenue Bond Resolution. In addition, Energy Northwest has other 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"). 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 2010 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. In 2009, Energy Northwest added three new members: Jefferson County and Lewis County Public Utility Districts and the City of Centralia. In 2010, Energy Northwest added another member in Public Utility District No. 1 of Pend Oreille County. Energy Northwest now has 28 members, consisting of 23 public utility districts and the cities of Centralia, Port Angeles, 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 1,157 megawatts. Energy Northwest also owns and operates a hydroelectric facility, the Packwood Lake Hydroelectric Project ("Packwood"), with a net design electric rating of 27.5 megawatts. Energy Northwest also owns and operates the Nine Canyon Wind Project, which consists of 63 turbines with a maximum generating capacity of approximately 96 megawatts. Energy Northwest also owns and has financial responsibility for four other nuclear electric generating projects that 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) for Projects 1 and 3 and Columbia, with payments being made through a combination of credits against customer bills and cash payments from the Bonneville Fund (hereinafter defined). Bonneville's obligations to make such payments under the Net Billing Agreements continue notwithstanding suspension or termination of any of Projects 1 or 3 or Columbia.

THE BONNEVILLE POWER ADMINISTRATION

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

Bonneville was created by Federal law in 1937 to market electric power from the Bonneville Dam and to construct facilities necessary to transmit such power. Today, Bonneville markets electric power from 31 federally-owned hydroelectric projects, most of which are located in the Columbia River Basin and all of which were constructed and are operated by the United States Army Corps of Engineers (the "Corps") or the United States Bureau of Reclamation (the "Bureau"), and from several non-federally-owned projects, including the Columbia Generating Station. Bonneville sells and/or exchanges power under contracts with over 125 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 eastern Montana, 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 over twelve million people. Electric power sold by Bonneville accounts for more than one-third 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 2010 BONDS

The Project 1 2010 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 1 Electric Revenue Bond Resolution. The Project 1 2010 Bonds are secured, on a subordinated basis to the Project 1 Prior Lien Bonds, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 1. The Project 1 2010 Bonds are secured on a parity with the Project 1 Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Project 1 Electric Revenue Bond Resolution or any Project 1 Separate Subordinated Resolution described under "SECURITY FOR THE NET BILLED BONDS - ADDITIONAL INDEBTEDNESS."

The Columbia 2010 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Columbia Electric Revenue Bond Resolution. The Columbia 2010 Bonds are secured, on a subordinated basis to the Columbia Prior Lien Bonds, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership and operation of Columbia. The Columbia 2010 Bonds are secured on a parity with the Columbia Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Columbia Electric Revenue Bond Resolution or any Columbia Separate Subordinated Resolution described under "SECURITY FOR THE NET BILLED BONDS - ADDITIONAL INDEBTEDNESS."

The Project 3 2010 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 3 Electric Revenue Bond Resolution. The Project 3 2010 Bonds are secured, on a subordinated basis to the Project 3 Prior Lien Bonds, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 3. The Project 3 2010 Bonds are secured on a parity with the Project 3 Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Project 3 Electric Revenue Bond Resolution or any Project 3 Separate Subordinated Resolution described under "SECURITY FOR THE NET BILLED BONDS - ADDITIONAL INDEBTEDNESS."

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

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

The 2010 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 2010 Bonds and other Electric Revenue Bonds relating to that Project. Accordingly, the owners of the 2010 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 December 31, 2009, 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 generally are required to be made directly by the Participants, not directly by Bonneville. 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 is required to pay 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 each Net Billing Agreement is required whether or not the related Net Billed Project is completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of Net Billed Project output or termination of the related Net Billed Project, and such payments or credits are not subject to any reduction, whether by offset or otherwise, and are not conditioned upon the performance or nonperformance by Energy Northwest, Bonneville or any Participant under the Net Billing Agreements or any other agreement or instrument.

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

As described under "SECURITY FOR THE NET BILLED BONDS - NET BILLING AND RELATED AGREEMENTS - Direct Pay Agreements," in 2006 Energy Northwest and Bonneville entered into an agreement with respect to each Net Billed Project pursuant to which Bonneville pays at least monthly all costs for each Net Billed Project directly to Energy Northwest. One effect of the Direct Payment Agreements is that each Participant pays Bonneville directly all costs associated with the Participant's contracts with Bonneville. The Direct Pay Agreements do not amend the Net Billing Agreements. Although the payments to Energy Northwest under the Direct Pay Agreements are included under the respective pledge of revenues for the related series of Net Billed Bonds, such agreements are not pledged to secure the payment of the related series of Net Billed Bonds and are subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest.

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

DESCRIPTION OF THE 2010 BONDS

GENERAL

The 2010 Bonds are dated the dates of their respective delivery set forth on the cover page, and mature on July 1 in the years and in the principal amounts shown on the inside cover pages of this Official Statement. The 2010 Bonds bear interest, payable on January 1 and July 1 of each year, commencing July 1, 2010, at the rates shown on the inside cover pages of this Official Statement. Interest on the 2010 Bonds will be calculated based on a 360-day year, consisting of twelve 30-day months. The Bank of New York Mellon Trust Company, N.A., Seattle, Washington, has been appointed the Trustee, Paying Agent and Registrar for the 2010 Bonds (collectively, the "Trustee"). For so long as the 2010 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.

Book-Entry System; Transferability and Registration

The 2010 Bonds are available to the ultimate purchasers in book-entry form only, in denominations of $5,000 and integral multiples thereof. Purchasers of the 2010 Bonds will not receive certificates representing their interests in such 2010 Bonds purchased, except as described in Appendix I - "BOOK-ENTRY SYSTEM" in this Official Statement. DTC will act as securities depository for each Series of 2010 Bonds. As discussed in Appendix I - "BOOK-ENTRY SYSTEM," transfers of ownership interests in the 2010 Bonds will be accomplished by book entries made by DTC and, in turn, by DTC Participants acting on behalf of Beneficial Owners of the 2010 Bonds. Energy Northwest, the Trustee and any other person may treat the Registered Owner of any 2010 Bond as the absolute owner of such 2010 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 2010 Bond shall be overdue or not. All payments of or on account of interest or principal to any Registered Owner of any such 2010 Bond shall be valid and effectual and shall be a discharge of Energy Northwest and the Trustee in respect of the liability upon such 2010 Bond, to the extent of the sum or sums paid.

When 2010 Bonds are registered in the name of Cede & Co., as nominee of DTC, Energy Northwest and the Trustee shall have no responsibility or obligation to any DTC Participant (as defined in Appendix I - "BOOK-ENTRY SYSTEM") or to any person on behalf of whom a DTC Participant holds an interest in the 2010 Bonds with respect to (1) the accuracy of the records of DTC, Cede & Co. or any DTC Participant with respect to any ownership interest in the 2010 Bonds, (2) the delivery to any DTC Participant or any other person, other than a Registered Owner as shown on the Bond Register, of any notice with respect to the 2010 Bonds, including any notice of redemption, (3) the payment to any DTC Participant or any other person, other than a Registered Owner as shown on the bond register, of any amount with respect to principal of, premium, if any, or interest on the 2010 Bonds, (4) the selection by DTC or any DTC Participant of any person to receive payment in the event of a partial redemption of the 2010 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 2010 Bond is registered, as the holder and absolute owner of such 2010 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 2010 Bonds, 2010 Bonds in fully registered form, in the denomination of $5,000 or any integral multiple thereof. Thereafter, the principal of the 2010 Bonds shall be payable upon due presentment and surrender thereof at the designated office of the Trustee, and interest on the 2010 Bonds will be payable by check or draft mailed to the persons in whose names such 2010 Bonds are registered, at the address appearing upon the registration books on the 15th day of the month next preceding an interest payment date; provided, however, that upon the written request of a Registered Owner of at least $1,000,000 in aggregate principal amount of a Series of the 2010 Bonds outstanding, interest will be paid by wire transfer on the date due to an account with a bank located in the United States. Principal of the 2010 Bonds is payable at the designated office of the Trustee. If the book-entry transfer system for the 2010 Bonds is discontinued, registered ownership of any 2010 Bond may be transferred or exchanged by surrendering such 2010 Bond to the Trustee, with the assignment form appearing on the 2010 Bond duly executed. The Trustee shall not be required to transfer any 2010 Bond during the 15 days preceding an interest payment or redemption date.

DESIGNATION OF SERIES 2010-C (TAXABLE) BUILD AMERICA BONDS AS "BUILD AMERICA BONDS"

Energy Northwest expects to make irrevocable elections (i) to have Section 54AA of the Internal Revenue Code of 1986, as amended (the "1986 Code") apply to the Series 2010-C (Taxable) Build America Bonds so that the Series 2010-C (Taxable) Build America Bonds are treated as "Build America Bonds," and (ii) to have Subsection 54AA(g) of the 1986 Code apply to the Series 2010-C (Taxable) Build America Bonds so that Energy Northwest will be allowed a credit payable by the United States Treasury to Energy Northwest pursuant to Section 6431 of the 1986 Code in an amount equal to 35% of the interest payable on the Series 2010-C (Taxable) Build America Bonds on each interest payment date. As a result of these elections, interest on the Series 2010-C (Taxable) Build America Bonds is not excludable from gross income of Beneficial Owners of the Series 2010-C (Taxable) Build America Bonds for federal income tax purposes, and Beneficial Owners of the Series 2010-C (Taxable) Build America Bonds will not be allowed any federal tax credits as a result of their ownership of or receipt of interest payments on the Series 2010-C (Taxable) Build America Bonds. See "TAX MATTERS—Series 2010-C (Taxable) Build America Bonds."

REDEMPTION

Optional Redemption

Series 2010-A Bonds. The Project 1 2010-A Bonds and the Project 3 2010-A Bonds are not subject to redemption prior to their stated maturities.

Series 2010-B Bonds. The Project 1 2010-B Bonds and the Project 3 2010-B Bonds are not subject to redemption prior to their stated maturities. The Columbia 2010-B Bonds maturing on and after July 1, 2021 are subject to redemption at the option of Energy Northwest (with the approval of Bonneville) on or after July 1, 2020, in whole or in part (with maturities to be selected by Energy Northwest, with the approval of Bonneville), on any Business Day, at a Redemption Price equal to 100% of the principal amount of the Columbia 2010-B Bonds to be redeemed, plus interest accrued to the date of redemption.

Series 2010-C (Taxable) Build America Bonds. The Series 2010-C (Taxable) Build America Bonds are subject to redemption prior to their respective maturities at the option of Energy Northwest (with the approval of Bonneville), in whole or in part, on any Business Day, at the Make-Whole Redemption Price (as defined herein) determined by the Designated Investment Banker (as defined herein). The "Make-Whole Redemption Price" is the greater of (i) the issue price as shown on the inside cover pages of this Official Statement (but not less than 100% of the principal amount of the Series 2010-C (Taxable) Build America Bonds to be redeemed), or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the Series 2010-C (Taxable) Build America Bonds to be redeemed, not including any portion of those payments of interest accrued and unpaid as of the date on which the Series 2010-C (Taxable) Build America Bonds are to be redeemed, discounted to the date on which such Series 2010-C (Taxable) Build America Bonds are to be redeemed on a semi-annual basis, assuming a 360-day year consisting of twelve 30-day months, at the "Treasury Rate" (defined below) plus 30 basis points, plus accrued and unpaid interest on the Series 2010-C (Taxable) Build America Bonds to be redeemed on the redemption date.

"Treasury Rate" means, with respect to any redemption date for a particular Series 2010-C (Taxable) Build America Bond, the rate per annum, expressed as a percentage of the principal amount, equal to the semi-annual equivalent yield to maturity or interpolated maturity of the Comparable Treasury Issue (defined below), assuming that the Comparable Treasury Issue is purchased on the redemption date for a price equal to the Comparable Treasury Price (defined below), as calculated by the Designated Investment Banker (defined below).

"Comparable Treasury Issue" means, with respect to any redemption date for a particular Series 2010-C (Taxable) Build America Bonds, the U.S. Treasury security or securities selected by the Designated Investment Banker that has an actual or interpolated maturity comparable to the remaining average life of the Series 2010-C (Taxable) Build America Bonds to be redeemed, and that would be utilized in accordance with customary financial practice in pricing new issues of debt securities of comparable maturity to the remaining average life of such Series 2010-C (Taxable) Build America Bonds to be redeemed.

"Comparable Treasury Price" means, with respect to any redemption date for a particular Series 2010-C (Taxable) Build America Bond, (i) if the Designated Investment Banker receives at least five Reference Treasury Dealer Quotations (defined below), the average of such quotations for such redemption date, after excluding the highest and lowest such Reference Treasury Dealer Quotations, or (ii) if the Designated Investment Banker obtains fewer than five Reference Treasury Dealer Quotations, the average of all such quotations.

"Designated Investment Banker" means one of the Reference Treasury Dealers appointed by Energy Northwest (with the approval of Bonneville).

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

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any redemption date for a particular Series 2010-C (Taxable) Build America Bond, the average, as determined by the Designated Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to Energy Northwest, the Trustee and Bonneville by such Reference Treasury Dealer at 3:30 p.m. (New York City time) on the date specified in the redemption notice, which date shall be no earlier than four days after the date of the redemption notice and no later than four days preceding such redemption date.

Extraordinary Optional Redemption

Series 2010-C (Taxable) Build America Bonds. The Series 2010-C (Taxable) Build America Bonds are subject to redemption at any time prior to their maturity at the option of Energy Northwest (with the approval of Bonneville), in whole or in part, upon the occurrence of an Extraordinary Event, at a redemption price (the "Extraordinary Optional Redemption Price") equal to the greater of (i) 100% of the principal amount of the Series 2010-C (Taxable) Build America Bonds to be redeemed, or (ii) the sum of the present values of the remaining scheduled payments of principal of and interest on the Series 2010-C (Taxable) Build America Bonds to be redeemed, not including any portion of those payments of interest accrued and unpaid as of the date on which the Series 2010-C (Taxable) Build America Bonds are to be redeemed, discounted to the date on which the Series 2010-C (Taxable) Build America Bonds are to be redeemed, on a semi-annual basis, assuming a 360-day year consisting of twelve 30-day months, at the Treasury Rate (defined above) plus 100 basis points plus accrued and unpaid interest on the Series 2010-C (Taxable) Build America Bonds to be redeemed to the redemption date.

An "Extraordinary Event" will have occurred if (a) Section 54AA or 6431 of the 1986 Code (as such Sections were added by Section 1531 of the American Recovery and Reinvestment Act of 2009, pertaining to "Build America Bonds") is modified or amended in a manner pursuant to which Energy Northwest's 35% cash subsidy payment from the United States Treasury Department is reduced or eliminated, or (b) guidance is published by the Internal Revenue Service or the United States

Treasury Department with respect to such Sections that places one or more substantive new conditions on the receipt by Energy Northwest of such 35% cash subsidy payments and such condition(s) are unacceptable to Energy Northwest or Bonneville.

Partial Redemption

If less than all of the 2010 Bonds are to be redeemed, Energy Northwest may select the Series and maturity or maturities to be redeemed. If less than all of the 2010 Bonds of a Series of any maturity are to be redeemed, the 2010 Bonds or portions thereof to be redeemed are to be selected by the Trustee or DTC, as applicable, by lot (except in the case of the Series 2010-C (Taxable) Build America Bonds), or in accordance with their respective standard procedures. The Electric Revenue Bond Resolutions related to such bonds provide that the portion of any 2010 Bonds of a denomination of more than $5,000 to be redeemed will be in the principal amount of $5,000 or any integral multiple thereof and that in selecting portions of such 2010 Bonds for redemption, the Trustee will treat each such 2010 Bonds as representing that number of such 2010 Bonds of $5,000 denomination that is obtained by dividing the principal amount of such 2010 Bonds to be redeemed in part by $5,000.

If the Series 2010-C (Taxable) Build America Bonds are not registered in book-entry only form, any redemption of less than all of a maturity of the Series 2010-C (Taxable) Build America Bonds shall be allocated among the registered owners of such Series 2010-C (Taxable) Build America Bonds as nearly as practicable in proportion to the principal amounts of the Series 2010-C (Taxable) Build America Bonds owned by each registered owner, subject to the authorized denominations applicable to the Series 2010-C (Taxable) Build America Bonds. This will be calculated based on the following formula:

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

The particular Series 2010-C (Taxable) Build America Bonds to be redeemed shall be determined by the Trustee, using such method as it shall deem fair and appropriate. If the Series 2010-C (Taxable) Build America Bonds are registered in book-entry only form, and so long as DTC or a successor securities depository is the sole registered owner of the Series 2010-C (Taxable) Build America Bonds, partial redemptions will be done in accordance with DTC procedures. It is Energy Northwest's intent that redemption allocations made by DTC, the DTC Participants or such other intermediaries that may exist between Energy Northwest and the Beneficial Owners be made in accordance with these same proportional provisions. However, Energy Northwest can provide no assurance that DTC, the DTC Participants or any other intermediaries will allocate redemptions among Beneficial Owners on such a proportional basis.

Notice of Redemption

Notice of redemption of any 2010 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 2010 Bonds which are to be redeemed at their last addresses shown on the registration books for the 2010 Bonds. Such notice shall be deemed conclusively to be received by the Registered Owners of the 2010 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 2010 Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the 2010 Bonds called for redemption shall become due and payable on the redemption date specified in such notice and interest thereon shall cease to accrue from and after the redemption date, if money sufficient for the redemption of the 2010 Bonds to be redeemed, together with interest thereon to the redemption date, is held by the Trustee for such 2010 Bonds on the redemption date and the 2010 Bonds (or such portions thereof) shall cease to be entitled to any benefit or security under the applicable resolutions. Energy Northwest may cancel notice of an optional redemption prior to the designated redemption date by giving written notice of such cancellation to all parties who were given notice of redemption in the same manner as such notice was given.

For so long as a book-entry system is in effect with respect to the 2010 Bonds, the Trustee will mail notices of redemption to DTC or its nominee or its successor, and, if less than all of the 2010 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 2010 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 2010 Bond of any redemption, will not affect the sufficiency or the validity or the redemption of 2010 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 2010 Bonds, or that they will do so on a timely basis.

Open Market Purchases

Energy Northwest has reserved the right to purchase any 2010 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 2010 Bond, and such 2010 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 2010 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 2010 Bond, in trust, and irrevocably appropriating and setting aside exclusively for such payment, either (1) moneys sufficient to make such payment, or (2) specified "defeasance obligations" maturing or redeemable at the option of the owner thereof, as to principal and interest in such amount and at such times as will assure the availability of sufficient money to make such payment, together with all necessary and proper fees, compensation and expenses of the Trustee and the paying agents pertaining to such 2010 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 THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS - Defeasance (Article XI)" for a discussion of defeasance of the 2010 Bonds.

As a condition to defeasing any Series 2010-C (Taxable) Build America Bonds, Energy Northwest must deliver to the Trustee for the Series 2010-C (Taxable) Build America Bonds either a ruling from the Internal Revenue Service (the "IRS") or an opinion of counsel to the effect that the Beneficial Owners of the Series 2010-C (Taxable) Build America Bonds will not recognize income, gain or loss for federal income tax purposes as a result of Energy Northwest's defeasance of such Series 2010-C (Taxable) Build America Bonds and will be subject to federal income tax on the same amount and in the same manner and at the same time as would have been the case if such defeasance had not occurred.

PURPOSE OF ISSUANCE

REFUNDING BONDS

The Project 1 2010 Bonds are being issued for the purpose of refunding $77,790,000 aggregate principal amount of the Project 1 Electric Revenue Bonds.

The Columbia 2010-B Bonds are being issued for the purpose of refunding $16,005,000 aggregate principal amount of the Columbia Electric Revenue Bonds.

The Project 3 2010 Bonds are being issued for the purpose of refunding $357,085,000 aggregate principal amount of the Project 3 Electric Revenue Bonds.

All proceeds of the Series 2010-A Bonds and Series 2010-B Bonds, together with other available amounts will be deposited in the respective debt service accounts for each Series of Refunded Bonds and may be, at the direction of Energy Northwest, used to purchase certain investment securities permitted by the Electric Revenue Bond Resolutions, respectively. The amounts deposited in the debt service accounts, together with the interest to accrue thereon, will be applied to pay the principal or redemption price, if any, and a portion of the interest on the Electric Revenue Bonds to be refunded as set forth in the following table.

The Electric Revenue Bonds to be refunded with the proceeds of the 2010 Bonds are identified below.

Electric Revenue Bonds to be Refunded:

Project	Series	Amount	Maturity (July 1)	Interest Rate	Redemption/ Maturity Date	Redemption Price
1	1993-1A	$ 76,955,000	2017	variable	March 26, 2010(1)	100%
1	2006-A	835,000(2)	2010	5.00%	July 1, 2010	N/A
Columbia	2008-D	16,005,000(2)	2010	5.00	July 1, 2010	N/A
3	1993-3A	15,795,000	2018	variable	March 26, 2010(1)	100%
3	2001-A	12,105,000	2010	5.50	July 1, 2010	N/A
3	2001-B	10,675,000	2018	variable(3)	July 1, 2010	100%
3	2003-E	98,025,000	2017	variable	March 26, 2010	100%
3	2008-D	11,655,000	2010	5.00	July 1, 2010	N/A
3	2008-F	104,415,000(4)	2018	variable	March 26, 2010	100%
3	2008-F	104,415,000(5)	2018	variable	March 26, 2010	100%

(1) Mandatory tender date.
(2) A portion of the 2010 maturity.
(3) Currently bearing interest at 5.50%.
(4) Subseries 2008-F-1; CUSIP Number 29280CTG0.
(5) Subseries 2008-F-2; CUSIP Number 29280CTH8.

NEW MONEY BONDS

The Series 2010-C (Taxable) Build America Bonds are being issued to finance a portion of the costs planned to be incurred during fiscal year 2011 for certain capital improvements at Columbia and to pay costs of issuance relating to the Series 2010-C (Taxable) Build America Bonds. The planned capital improvements of approximately $91 million at Columbia, of which approximately $75 million will be financed with Series 2010-C (Taxable) Build America Bond proceeds, include: various computer system upgrades; plant fire detection system upgrade; plant license extension; replacement of the main condenser;

replacement of radiation monitors; replacement of the main generator rotor; rebuild of main transformer; cooling tower fill replacement; rebuild or replacement of numerous other pumps, motors, valves and piping; and replacement of various pieces of equipment.

SOURCES AND USES OF FUNDS

SOURCES OF FUNDS:

Project 1	
Principal of Project 1 2010-A Bonds	$ 71,150,000
Principal of Project 1 2010-B Bonds	815,000
Net Original Issue Premium	5,819,131
Other Funds of Energy Northwest	431,350
Total	$ 78,215,481
Columbia	
Principal of Columbia 2010-B Bonds	$ 16,005,000
Principal of Series 2010-C (Taxable) Build America Bonds	75,770,000
Other Funds of Energy Northwest	112,451
Total	$ 91,887,451
Project 3	
Principal of Project 3 2010-A Bonds	$ 279,980,000
Principal of Project 3 2010-B Bonds	29,865,000
Net Original Issue Premium	47,234,495
Other Funds of Energy Northwest	2,289,006
Total	$ 359,368,501

USES OF FUNDS:

Project 1	
Deposit with refunding trustees for refunded Project 1 Electric Revenue Bonds	$ 77,789,843
Costs of Issuance	425,638
Total	$ 78,215,481
Columbia	
Capital Improvements	$ 75,107,900
Costs of Issuance	777,934
Deposit with refunding trustee for refunded Columbia Electric Revenue Bonds	16,001,617
Total	$ 91,887,451
Project 3	
Deposit with refunding trustees for refunded Project 3 Electric Revenue Bonds	$ 357,077,719
Costs of Issuance	2,290,782
Total	$ 359,368,501

SECURITY FOR THE NET BILLED BONDS

PLEDGE OF REVENUES AND PRIORITY

The Project 1 2010 Bonds are special revenue obligations of Energy Northwest issued under and 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 ($41,070,000 of which were outstanding as of December 31, 2009), to the lien and pledge of the Project 1 Prior Lien Resolution. The Project 1 2010 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 2010 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 2010 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 December 31, 2009, $1,780,095,000 principal amount of Project 1 Electric Revenue Bonds.

The Columbia 2010 Bonds are special revenue obligations of Energy Northwest issued under and 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 ($150,200,000 of which were outstanding as of December 31, 2009), to the lien and pledge of the Columbia Prior Lien Resolution. The Columbia 2010 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 2010 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 2010 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 December 31, 2009, $2,242,275,000 principal amount of Columbia Electric Revenue Bonds.

The Project 3 2010 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 ($332,495,000 of which were outstanding as of December 31, 2009), to the lien and pledge of the Project 3 Prior Lien Resolution. The Project 3 2010 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 Electric Revenue 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 2010 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 December 31, 2009, $1,396,510,000 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 2010 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 2010 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 2010 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 2010 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 2010 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 2010 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 2010 Bonds, the Columbia 2010 Bonds and the Project 3 2010 Bonds are separately secured and are not general obligations of Energy Northwest. The owners of the Project 1 2010 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Columbia 2010 Bonds and the Project 3 2010 Bonds. The owners of the Columbia 2010 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2010 Bonds and the Project 3 2010 Bonds. The owners of the Project 3 2010 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2010 Bonds and the Columbia 2010 Bonds. No Bondholder has a claim on the assets of any Project.

The 2010 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 THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE 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 2010 Bonds, see Appendix H-1 - "SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS - Events of Default and 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 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 THE 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 THE PRIOR LIEN RESOLUTIONS - Certain Covenants."

If the maturity of Prior Lien Bonds or Electric Revenue Bonds, including the 2010 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.

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 THE 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 2010 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 2010 Bonds, there can be no assurance that available remedies will be adequate to fully protect the interest of the owners of the 2010 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 2010 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 Foster Pepper PLLC, as Bond Counsel, concurrently with the issuance of the 2010 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 2010 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. 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 2010 Bonds, pursuant to Separate Subordinated Resolutions, other than that the Net Billing Agreements and other Project agreements must be in effect and no event of default may exist under the applicable Electric Revenue Bond Resolution.

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

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

NET BILLING AND RELATED AGREEMENTS

General

Energy Northwest sold the entire capability of Project 1 to 104 publicly-owned utilities and rural electric cooperatives (the "Project 1 Participants") under net billing agreements (as amended, the "Project 1 Net Billing Agreements"). Energy Northwest sold the entire capability of the Columbia Generating Station to 94 publicly-owned utilities and rural electric cooperatives (the "Columbia Participants") under net billing agreements (the "Columbia Net Billing Agreements"). Energy Northwest sold the entire capability of its ownership share of Project 3 to 103 publicly-owned utilities and rural electric cooperatives (the "Project 3 Participants," and collectively with the Project 1 Participants and the Columbia Participants, the "Participants") under net billing agreements (the "Project 3 Net Billing Agreements," which, together with the Project 1 Net Billing Agreements and the Columbia Net Billing Agreements, are collectively referred to as the "Net Billing Agreements"). Under the Net Billing Agreements, each Participant assigned its share of the capability of the Net Billed Project to Bonneville. Each of the Participants is a customer of Bonneville. Many of the Participants are Participants in more than one Net Billed Project. See Appendix F - "ENERGY NORTHWEST PARTICIPANT UTILITY SHARE OF FISCAL YEAR 2010 BUDGETS" for a list of Participants and their respective shares of the Projects' Fiscal Year 2010 Budgets.

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

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

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

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

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

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

As described under "SECURITY FOR THE NET BILLED BONDS - NET BILLING AND RELATED AGREEMENTS - Direct Pay Agreements," Energy Northwest and Bonneville executed an agreement with respect to each Net Billed Project pursuant to which Bonneville agrees to monthly pay all costs for each Net Billed Project directly to Energy Northwest and each Participant pays Bonneville directly all costs associated with the Participant's contracts with Bonneville. Although the payments to Energy Northwest under the Direct Pay Agreements are included under the respective pledge of revenues for the related series of Net Billed Bonds, such agreements are not pledged to secure the payment of the related series of Net Billed Bonds and are subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest.

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

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

Payment Procedures

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

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

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

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

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

Post Termination Agreements

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

Assignment of Participant Shares

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

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

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

Voluntary Payments by Bonneville to Energy Northwest on Behalf of Participants

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

Assignment Agreements

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

Direct Pay Agreements

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

Other Net Billing Obligations

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

Bonneville is authorized to enter into additional contracts providing for net billing or similar credits. The Net Billing Agreements provide that Bonneville and each Participant shall not enter into any agreement providing for net billing if Bonneville estimates that, as a result of such agreement, the aggregate of its billings to such Participant will be less than 115% of Bonneville's net billing obligations to such Participant under all agreements between Bonneville and such Participant providing for net billing. Bonneville has no present plans to enter into new agreements requiring net billing with Participants.

THE BONNEVILLE FUND

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

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

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

Bonneville is required to make certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System (as defined in Appendix A - "THE BONNEVILLE POWER ADMINISTRATION"), other than those used to make payments to the United States Treasury for: (i) the repayment of the Federal investment in certain transmission facilities and the power generating facilities at federally-owned hydroelectric projects in the Pacific Northwest; (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury; (iii) repayments of amounts appropriated to the Corps and the Bureau for costs allocated to power generation at federally-owned hydroelectric projects in the Pacific Northwest; and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its fiscal year 2009 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 made all payments to the United States Treasury in full and on time since 1984.

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

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

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

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

ENERGY NORTHWEST

GENERAL

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

Energy Northwest owns and operates Columbia and Packwood, which are currently in operation, and have net design electric ratings of 1,157 megawatts and 27.5 megawatts, respectively. Energy Northwest also owns and operates the Nine Canyon Wind Project, which has a maximum generating capacity of approximately 96 megawatts. Energy Northwest also owns and/or has financial responsibility for four nuclear electric generating projects that have been terminated: Projects 1, 3, 4 and 5. For discussions concerning the termination of Projects 1, 3, 4 and 5, see "- Project 1," "- Project 3" and "- Projects 4 and 5."

Each of Energy Northwest's projects is treated and accounted for by Energy Northwest as a separate utility system, with the exception of Projects 4 and 5, which together comprised a single utility system. Under Washington law, a joint operating agency may create separate special funds for each of its utility systems and Energy Northwest has done so. The resolutions of Energy Northwest pursuant to which its various series of bonds are issued provide that the income, receipts and revenues of each utility system are pledged solely to the payment of obligations incurred in connection with that utility system. See Appendix C - "AUDITED FINANCIAL STATEMENTS OF ENERGY NORTHWEST PROJECTS FOR THE YEAR ENDED JUNE 30, 2009" 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, 2009.

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 December 31, 2009.

ENERGY NORTHWEST REVENUE BONDS
OUTSTANDING AS OF DECEMBER 31, 2009

REVENUE BONDS	PRINCIPAL AMOUNT
PROJECT 1:	
Prior Lien Refunding Revenue Bonds	$ 41,070,000
Electric Revenue Refunding Bonds	1,780,095,000
TOTAL PROJECT 1	$ 1,821,165,000
COLUMBIA:	
Prior Lien Refunding Revenue Bonds	$ 150,200,000
Electric Revenue and Refunding Bonds	2,242,275,000
TOTAL COLUMBIA	$ 2,392,475,000
PROJECT 3:	
Prior Lien Refunding Revenue Bonds	$ 332,495,000 (1)
Electric Revenue Refunding Bonds	1,396,510,000
TOTAL PROJECT 3	$ 1,729,005,000
TOTAL NET BILLED REVENUE BONDS	$ 5,942,645,000
Nine Canyon Wind Project Revenue Bonds (2)	$ 144,730,000

(1) Includes $197,546,571 accreted value of Compound Interest Bonds for Project 3, as of July 1, 2009.
(2) Bonneville is not a party to any agreements that secure payment of the Nine Canyon Wind Project Bonds.

In 2000, Bonneville presented to Energy Northwest a proposal for a "Debt Optimization Program." The Debt Optimization Program involved extending the final maturities of outstanding Columbia Net Billed Bonds coming due prior to 2013 through a series of refunding bond issues. Implementing the Debt Optimization Program was intended to provide Bonneville with cash flow flexibility in funding planned capital expenditures, allow Bonneville to advance the amortization of Bonneville's United States Treasury debt and reduce Bonneville's overall fixed costs. Bonneville manages its overall debt portfolio to meet the objectives of: (1) minimizing the cost of debt to Bonneville's rate payers; (2) maximizing Bonneville's access to its lowest cost capital sources to meet future capital needs and minimize costs to rate payers; and (3) maintaining sufficient financial flexibility to meet Bonneville's financial requirements. See "THE BONNEVILLE POWER ADMINISTRATION - BONNEVILLE FINANCIAL OPERATIONS - Debt Optimization Program" in Appendix A. In 2000, Energy Northwest, in response to the Bonneville proposal, adopted a Refunding Plan, which essentially adopted the Debt Optimization Program as proposed by Bonneville. In 2001, at Bonneville's request to increase the scope of the Debt Optimization Program, Energy Northwest revised such 2000 Refunding Plan to increase the average life of outstanding Projects 1 and 3 Net Billed Bonds by extending the maturity of such Projects 1 and 3 Net Billed Bonds for any future refinancing of such bonds. An additional objective of the Refunding Plan is to advance refund outstanding, noncallable Net Billed Bonds when deemed appropriate by Energy Northwest and Bonneville. A number of the Electric Revenue and Refunding Bonds reflected in the previous table also were issued as part of the Debt Optimization Program or Refunding Plan.

Bonneville and Energy Northwest currently do not expect to undertake future Energy Northwest debt refundings for the purpose of implementing the Debt Optimization Program. However, Bonneville and Energy Northwest do expect to undertake future refundings which extend maturities of outstanding Energy Northwest debt. For example, the Project 1 2010-B Bonds, the Columbia 2010-B Bonds, and the Project 3 2010-B Bonds are being issued to extend final maturities of Energy Northwest debt but are not being issued as part of the Debt Optimization Program. The purpose of these future refundings is expected to be to extend final Energy Northwest debt maturities in order to enable Bonneville to maintain financial flexibility to meet its financial requirements and to reduce Bonneville's overall fixed costs.

ORGANIZATIONAL STRUCTURE

Energy Northwest currently has a membership of 28, consisting of 23 public utility districts and the cities of Centralia, Port Angeles, 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 28 utility members, one from each of the member utilities. Pursuant to the Act, the powers and duties of the Board of Directors are limited to (i) final authority on any decision to acquire, construct, terminate or decommission any power plants, works and facilities, except that once such a final decision is made with respect to a nuclear power plant, the Executive Board has authority to make all subsequent decisions regarding such plant; (ii) the election and removal of, and establishment of salaries for, the five members of the Executive Board selected from among the members of the Board of Directors; and (iii) the selection of three of the six members of the Executive Board who are outside directors. All other powers and duties of Energy Northwest, including but not limited to the authority to sell any power plant, works and facilities, are vested in the Executive Board.

The Act provides that five of the members of the Executive Board of Energy Northwest are elected by the Board of Directors from among its members and six are outside directors representative of policy makers in business, finance or science, or having expertise in the construction or management of facilities such as those owned by Energy Northwest. Three of these six outside directors are selected by the Board of Directors and three by the Governor of the State of Washington subject to confirmation by the Washington State 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 State 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
Sid W. Morrison, Chairman	Retired Executive	June 2013
Tom Casey, Vice Chairman	Public Utility District Commissioner	June 2010
Kathleen Vaughn, Secretary	Public Utility District Commissioner	June 2010
Bill Gordon, Assistant Secretary	Public Utility District Commissioner	June 2010
Edward E. Coates	Retired Utility Executive	June 2010
K.C. Golden	Executive	June 2009*
Dan G. Gunkel	Public Utility District Commissioner	June 2010
Jack Janda	Public Utility District Commissioner	June 2010
Lawrence Kenney	Retired Organized Labor Executive	June 2010
David Remington	Financial Consultant	June 2012
Tim Sheldon	Washington State Senator	June 2012

---

* K.C. Golden is considered a member of the Executive Board until reappointed, or his appointment is rescinded or another member is appointed by the Governor of the State of Washington.

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	39 years
W. Scott Oxenford	Vice President, Nuclear Generation/Chief Nuclear Officer	26 years
John W. Baker	Vice President, Energy/Business Services	38 years
Sudesh K. Gambhir	Vice President, Technical Services	31 years
Dale K. Atkinson	Vice President, Operational Support	32 years
Albert E. Mouncer	Vice President, Corporate Services/General Counsel/Chief Financial Officer	29 years

---

* Joseph V. Parrish will retire effective July 2010. Mr. Parrish announced his intent to retire in July 2009. The Energy Northwest Executive Board appointed an Ad Hoc Search Committee to identify a new Chief Executive Officer. The Executive Board anticipates making the selection by spring 2010 to allow time for transition.

EMPLOYEES

Energy Northwest currently employs approximately 1,196 employees. Of these employees, 321 are members of the International Brotherhood of Electrical Workers ("IBEW"), 143 are members of the United Steel Workers ("USW") and eight are members of the Hanford Atomic Metal Trades Council ("HAMTC") unions. The IBEW union members comprise the Administrative, Nuclear, Travelers and Plant bargaining groups; the USW union members constitute the Security Force bargaining group; and the HAMTC union members comprise part of the Standards Lab Instrument Technicians. All of the collective bargaining agreements will expire in the fall of 2012. A no-strike clause is included in each of the agreements.

INVESTMENT POLICY

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

Investment securities purchased consist generally of obligations of, or obligations the principal and interest on which is unconditionally guaranteed by, the United States of America or other investment securities permitted by the related Net Billed Resolutions and Prior Lien Resolutions. The 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 THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS - Investment of Funds (Section 508)" and Appendix

H-2 - "SUMMARY OF CERTAIN PROVISIONS OF THE PRIOR LIEN RESOLUTIONS - Other Funds Established by the Prior Lien Resolutions; Flow of Revenues."

THE COLUMBIA GENERATING STATION

Description

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 1,157 megawatts. Columbia consists of a General Electric Company-designed boiling water reactor and nuclear steam supply system, a Westinghouse turbine-generator and the necessary transformer, switching and transmission facilities to deliver the output to the transmission facilities of the Federal System located in the vicinity of Columbia. Bonneville has acquired the entire capability of Columbia under the Columbia Net Billing Agreements. See "SECURITY FOR THE NET BILLED BONDS - NET BILLING AND RELATED AGREEMENTS."

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

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

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

Management Discussion of Operations

All the power from Columbia is sold at cost to Bonneville through the Columbia Net Billing Agreements. Energy Northwest has a maintenance, operating, fuel and capital budget for Columbia of $318 million for the 2010 fiscal year, which ends on June 30, 2010.

The cost of production, using industry standard methodology (such cost calculation methodology includes general, administration and capital costs, but excludes debt service, taxes, depreciation and decommissioning costs), of Columbia electricity is budgeted at $34.32 per megawatt-hour for the 2010 fiscal year. This cost is lower than the $48.24 per megawatt-hour for the 2009 fiscal year because the 2009 fiscal year included a refueling outage. The next scheduled outage will be in May 2011. Energy Northwest continues to place a high priority on cost-containment.

On May 8, 2009 the plant was shutdown due to a decrease in pressure on the main generator and loss of seal oil. The plant remained down for the planned refueling outage, which was scheduled to begin May 9, 2009. Since reconnecting to the Federal System grid on June 24, 2009, the plant has been shutdown four additional times, for a total of 45 days offline. The causes of these shutdowns were due to a main turbine lube oil leak, an electrical fault and fire, repair of a limit switch malfunction, and a hydraulic leak in the digital electro-hydraulic control system. The plant has run continuously since reconnection to the Federal System grid on November 14, 2009.

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

To increase the regional value of the plant's generating capability over time, engineers continue to work on a proposal to renew Columbia's 40-year operating license by 20 years, from 2023 to 2043. The NRC established a protocol to handle license renewal applications and has granted numerous such requests since 2000. The final Columbia License Renewal Application was submitted in January 2010.

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 71.8% and has generated 173,432,602 megawatt hours (net of station use) of electric power through December 2009. However, in the past nine calendar years ending December 31, 2009, the cumulative capacity factor has been 87.1%.

Successful implementation of employee performance enhancement initiatives at Columbia has produced significant positive results in plant performance. Fiscal year 2006 was the best generating fiscal year at Columbia since commencing commercial operation, eclipsing the previous record in 2004. In fiscal year 2006, Columbia produced 9,636 million kilowatt hours of electric power while attaining a plant capacity factor of 99.4% and a plant availability factor of 99.6%. Columbia had its second best fiscal year generation in 2008 with production of 9,594 million kilowatt hours of electric power with a plant capacity factor of 98.9%. Columbia produced 7,725 million kilowatt hours of electric power in fiscal year 2009. Generation was down 19.5% from fiscal year 2008 due to the completion of its two-year refueling and maintenance outage, two forced outages (in August 2008 and February 2009), a down-power to 60% for one week in April 2009 to allow for feed water pump work and a maintenance outage in November 2008.

Annual Costs

Annual costs for Columbia are derived from the audited financial statements for fiscal years ended June 30, 2008 and 2009 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 2008	FY 2009
Operations, Maintenance and Overhead	$185,167	$282,503
Nuclear Fuel	35,873	27,118
Spent Fuel Disposal Fee	9,036	7,380
Generation Taxes	4,019	3,137
Decommissioning	6,163	6,457
Depreciation and Amortization	72,983	77,063
Investment Income	(4,426)	(1,993)
Interest Expense and Discount Amortization	121,464	118,981
Other Expense/(Revenue)	(1,285)	(888)
Total Costs	$428,994	$519,758
Net Generation (GWhs) (unaudited)	9,594	7,725[(2)]

(1) Amounts derived from audited Energy Northwest financial statements.
(2) The decrease in generation from fiscal year 2008 to fiscal year 2009 was due to a refueling and maintenance outage and four unplanned outages.

Capital Improvements

Energy Northwest has been making capital improvements to Columbia since it began commercial operation. Prior to 2003, these additional capital expenditures at Columbia were funded through the Columbia Net Billing Agreements, without borrowings by Energy Northwest. Since 2003, Energy Northwest has funded some or all of its additional capital expenditures at Columbia through the issuance of Electric Revenue Bonds.

In fiscal year 2009, Energy Northwest spent $70.7 million on capital improvements at Columbia. Energy Northwest expects to spend $82.5 million on capital improvements at Columbia in fiscal year 2010 and $91 million in fiscal year 2011. The capital improvements at Columbia include various computer system and security upgrades; plant fire detection system upgrade; plant license extension; replacement of the main condenser (the fiscal year 2009 Columbia Generating Station long-range plan estimated that the cost of the main condenser project would be $95 million over three years); replacement of the reactor recirculation motors and pumps; cooling tower fill replacement; rebuild or replacement of numerous other pumps, motors, valves and piping; and replacement of various pieces of equipment. The Series 2010-C (Taxable) Build America Bonds will finance the cost of these capital improvements in fiscal year 2011.

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 assigns 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. For the Third Quarter of 2009, the reactor safety and radiation safety cornerstones had only Green findings. All but one performance indicator were also in the Green finding region. The Unplanned Scrams Per 7,000 Critical Hours performance indicator was in the White region and will remain so until following Second Quarter 2010. The scram rate is an incident rate calculated per 7,000 critical hours because that value is representative of the critical hours of operation in a year for a typical plant. The Safeguards (Physical Protection) cornerstone information is not publicly available.

Results from the monitored cornerstones are compiled and published quarterly in the NRC's Reactor Oversight Process Action Matrix Summary at www.nrc.gov. The Safeguards (Physical Protection) cornerstone performance indicators and inspection findings are not integrated into the Action Matrix Summary. The Action Matrix Summary reflects overall plant performance, which is based on defined performance indicators and inspection findings. Individual plant performance is segregated into one of five performance columns.

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

The NRC's Third Quarter 2009 Regulatory Oversight Process Summary lists 80 plants in the Licensee Response Column, 23 plants, including Columbia, in the Regulatory Response Column, one plant in the Degraded Cornerstone Column, and no plants in the next two lower columns, including the Unacceptable Performance Column. Columbia's position in the Regulatory Response Column, due to the white performance indicator, will result in one additional inspection to assess Columbia's evaluation of cause and identified corrective actions. Columbia is expected to return to the Licensee Response Column following the second quarter of 2010.

Institute of Nuclear Power Operations

The nuclear electric industry created the Institute of Nuclear Power Operations ("INPO") in 1979. The INPO 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 completed a peer evaluation of Columbia in December 2008. 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 exemplary. Industry standards of excellence are met in many areas. No significant weaknesses noted." Energy Northwest had previously established an improvement program that will address areas for improvement identified in the evaluation.

In January 2009, Energy Northwest initiated conversations with the INPO to assist improvement efforts at Columbia by sending a Special Focus Team to evaluate the progress at Columbia. This team visited Columbia in November 2009 and concluded that efforts to address areas for improvement (identified during the evaluation concluded in December 2008) "have not progressed adequately." In December 2009, Energy Northwest requested inclusion in a special focus program, in which Energy Northwest can leverage INPO expertise to receive dedicated oversight and frequent assessment reports on Columbia operations.

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 May 2011 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. The Corps has issued a permit for construction and maintenance of the completed river facilities. Energy Northwest has an interim status permit for storage of mixed radioactive and hazardous wastes. 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 hexafluoride, enrichment of the uranium hexafluoride and fabrication of the enriched uranium in the form of uranium oxide pellets into finished fuel assemblies.

Fabrication services for the 2009 through 2013 reloads will be provided pursuant to a contract with Global Nuclear Fuels – Americas, LLC.

Columbia operates on a 24-month fuel cycle. A 24-month fuel cycle eliminates the need for refueling outages every year and results in increased average generation.

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 uranium is sufficient for plant requirements through 2012.

Energy Northwest has a contract with DOE that requires the DOE to accept title and dispose of spent nuclear fuel. For this future service, Energy Northwest pays a quarterly fee based on about one mill per kilowatt-hour of net electricity generated and sold from Columbia ($7.38 million for the 12 months ended June 30, 2009). To permanently store the spent fuel from the nation's nuclear plants, DOE is evaluating proposed sites for a repository. Although courts ruled that DOE has an obligation to begin taking title to the spent fuel no later than January 31, 1998, currently, there is no known date established when DOE will fulfill this legal obligation and begin accepting spent nuclear fuel. 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. See "NET BILLED PROJECTS LITIGATION AND CLAIMS – Energy Northwest v. United States of America."

Energy Northwest commenced construction of the Independent Spent Fuel Storage Installation ("ISFSI") facility in 2002 to store spent fuel in commercially available dry storage casks on concrete pads at the plant site. The ISFSI facility can be expanded in increments to accommodate future spent fuel discharges when 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 $877.0 million (in 2009 dollars). This estimate is based on the NRC minimum amount required to demonstrate reasonable financial assurance for a boiling water reactor with the power level of Columbia. Additionally, site restoration requirements for Columbia are governed by the site certification agreements between Energy Northwest and the State of Washington and regulations adopted by the Washington Energy Facility Site Evaluation Council. Energy Northwest's estimate of Columbia's site restoration costs is approximately $107.1 million (in 2009 dollars).

The current decommissioning funding plan requires annual deposits to a fund through fiscal year 2024, the end of Columbia's current operating license with the NRC. 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 November 30, 2009, totaled approximately $132 million. A separate fund has been established for site restoration. The balance of this fund as of November 30, 2009, totaled approximately $20 million. These amounts are held in external accounts 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 damages arising out of a nuclear incident. Federal law limits public liability for claims resulting from any nuclear incident to $12.595 billion under the Price-Anderson Act, as an amendment to the Atomic Energy Act of 1954 (as amended, "Price-Anderson").

In accordance with Price-Anderson, Energy Northwest has secured the maximum available insurance of $375 million in coverage for Columbia's public liability exposure. The remaining $12.22 billion of exposure is funded by the Secondary Financial Protection Program, available through assessments by the federal government in case of a nuclear accident. Under Price-Anderson, all nuclear reactor licensees can be assessed a maximum charge per reactor per incident. The maximum assessment for each nuclear operator per reactor per incident is $117.5 million, payable at no more than $17.5 million per reactor per incident per year (this assessment is payable under the Columbia Net Billing Agreements). The maximum deferred premium per reactor and the yearly assessment per reactor for each nuclear incident will be adjusted for inflation every five years. The next inflation adjustment should occur no later than October 29, 2013.

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

PACKWOOD LAKE HYDROELECTRIC PROJECT

Energy Northwest owns and operates Packwood, a hydroelectric generating facility with a net design electric rating of 27.5 megawatts. Packwood is located near the town of Packwood in Lewis County, Washington, approximately 75 miles southeast of Seattle, Washington. Packwood was granted a FERC operating license on March 1, 1960, and began commercial operation in June 1964. The initial FERC license has a duration of 50 years and expires on February 28, 2010. Based on the existing FERC licensing process, Energy Northwest initiated relicensing efforts in fiscal year 2005 and an application requesting a new 50-year license was submitted to FERC in April 2008. Energy Northwest anticipates receiving a decision by FERC in the spring of 2010. If the decision is delayed beyond the current license expiration of February 28, 2010, the plant will continue to run under its initial license until FERC's decision is rendered.

In fiscal year 2009, Packwood experienced its highest generation levels since 2000, which were 14.2% above the 30 year average annual generation for the facility of 86,970 megawatt-hours. In fiscal year 2009, production at Packwood totaled 99,340 net megawatt hours, up 28.2% from the previous year due to an excellent snowpack and ample water available for generation. The electric power produced at the facility is expected to generate enough revenues to pay all Packwood costs, including debt service on any Packwood bonds or notes. In November 2006, Packwood experienced damage due to land slides from the rain and flooding in Lewis County, Washington. Energy Northwest has requested grant money to make the necessary repairs and in December 2007, Packwood took out a line of credit with Bank of America, N.A. in the amount of not to exceed $1.3 million to provide interim financing for costs associated with repairing damage done to Packwood in recent landslide damage. The line of credit matured in December 2009, and Energy Northwest paid all outstanding balances on such line of credit at that time.

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. Public Utility District No. 1 of Snohomish County is purchasing all the energy output of Packwood from the other participants for the period October 2008 to October 2011.

NINE CANYON WIND PROJECT

Energy Northwest owns and operates the Nine Canyon Wind Project, a wind energy project, which is capable of generating 95.9 megawatts of electricity. The project is located on leased land, near Kennewick, Washington. 49 wind turbines of the Nine Canyon Wind Project have a power generating capacity of 1,300 kilowatts each and there are an additional 14 wind turbines with 2,300 kilowatts of power generating capacity each. The turbines were manufactured by Siemens Power Generation, Inc. (previously BONUS Energy A/S). The project is a separate system of Energy Northwest and the bonds are secured by, and payable solely from, the revenues derived by Energy Northwest under power purchase agreements executed with public utility purchasers. The purchasers are required to pay their share of the annual budget of the project, which includes debt service on the related bonds, whether or not the project is operating or capable of operating. Power costs for the project billed to the purchasers ranged from 5.0 cents per kilowatt hour to 6.4 cents per kilowatt hour during fiscal year 2009.

In fiscal year 2009, Nine Canyon produced 226,270 net megawatt-hours of electricity compared to 237,330 net megawatt-hours in fiscal year 2008 due to lower wind speed averages.

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 facilitates the administration, budgeting and payment processes post termination. After termination, Energy Northwest offered to sell assets in the form of uninstalled operating equipment and construction materials since there was no market for the sale of Project 1 in its entirety. Certain of these assets have been sold.

Energy Northwest has been planning for the demolition of Project 1 and restoration of the site. In addition to funding for the payment of debt service on Project 1 Net Billed Bonds, funding has continued for administrative efforts associated with asset sales and planning for the demolition and site restoration activities for Project 1. Sources of funding are derived through the Project 1 Net Billing Agreements. The Project 1 Post Termination Agreement requires Bonneville to fund this site remediation plan for Projects 1 and 4. The cost for both sites' remediation is estimated at $22.5 million in calendar year 2009 dollars. Bonneville has placed funds in an external interest-bearing account in order to have sufficient funds for the eventual final remediation.

PROJECT 3

Project 3 is a partially complete nuclear electric generating project located in southeastern Grays Harbor County, Washington, approximately 70 miles southwest of Seattle, Washington and was terminated in June 1994. The Project 3 Project Agreement and the Project 3 Net Billing Agreements ended upon termination of Project 3, except for certain provisions relating to billing and payment processes. See "SECURITY FOR THE NET BILLED BONDS - NET BILLING AND RELATED AGREEMENTS - Payment Procedures" in this Official Statement. The Project 3 Post Termination Agreement 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. In 1999, Energy Northwest transferred the Project 3 site properties and facilities (other than the Satsop combustion turbine site) to such local public agencies for purposes of economic development. In connection with that transfer, these local public agencies assumed responsibility for any required site remediation. The Satsop combustion turbine site was sold in 2001 to Duke Energy Grays Harbor LLC for $10 million.

PROJECTS 4 AND 5

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

ENERGY/BUSINESS SERVICES

More than a decade ago, Energy Northwest set out to develop new sources of electricity generation and provide energy and environmental related services to meet the needs of its member utilities and the region. Since 1992, Energy Northwest has provided a wide range of chemical analysis and environmental monitoring services to utility, municipal, commercial, and nuclear customers. Energy Northwest is a founding member of NoaNet, offering access to a fiber-optic cable network licensed from

Bonneville and other broadband providers. Energy Northwest is actively investing in emerging technologies through its support of the Applied Process Engineering Laboratory, currently in its eleventh year of operation.

FUTURE RESOURCES

Energy Northwest has executed a joint development agreement for the Radar Ridge Wind Project (the "Radar Ridge Wind Project") with Public Utility Districts No. 1 of Clallam and Grays Harbor Counties, Public Utility District No. 3 of Mason County and Public Utility District No. 2 of Pacific County for a site in Pacific County near Naselle, Washington. Energy Northwest has entered into a 40-year lease with the Department of Natural Resources that will support up to 32 multi-megawatt wind turbines and has submitted a request to Bonneville to interconnect the Radar Ridge Wind Project at its Naselle 115kV substation as a network expansion. An Interconnection Feasibility Study determined that up to 82 megawatts of existing electrical capacity is available at this location. Public Utility District No. 2 of Pacific County has agreed to develop a project substation, collection, distribution and transmission facilities to serve the Radar Ridge Wind Project and will own, operate and maintain this infrastructure for the life of the project.

Energy Northwest holds an option to lease approximately 16 acres at the Port of Kalama for a potential natural gas project. Development options for the natural gas power plant on this site are being assessed.

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

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:

Energy Northwest v. United States of America. This is an action filed by Energy Northwest against the United States of America (the "Government") in the U.S. Court of Federal Claims in January 2004 for breach of contract and breach of implied covenant of good faith and fair dealing. On June 13, 1983, Energy Northwest entered into a written contract with the United States for disposal of spent nuclear fuel ("SNF") and high-level radioactive waste. The Government, in its contract, agreed to accept and dispose of the SNF beginning not later than January 31, 1998. The Government failed to meet its obligation. Energy Northwest seeks recovery of damages for, among other things, substantial costs resulting from the Government's breach of contract, including but not limited to (1) the costs to investigate, design, license, and construct alternative storage facilities and to purchase and load casks to store SNF at those facilities; and (2) the operations, maintenance, and security costs Energy Northwest will incur to store SNF at Columbia beyond the time that the Government would have removed all the SNF had it not breached the Standard Contract. On January 30, 2006, the U.S. Court of Federal Claims ruled that the Government breached its contract with Energy Northwest as of January 31, 1998, when it failed to begin accepting SNF from the nuclear utility industry on that date. Trial occurred in February, 2009. Post trial briefing was completed in July 2009. No decision has been rendered by the Court and the extent of the damages award cannot be predicted at this time.

LEGAL MATTERS

The approving opinions of Foster Pepper PLLC, Bond Counsel to Energy Northwest, as to the legality of the 2010 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 2010-A Bonds and Series 2010-B Bonds from the gross income of the owners thereof for federal income tax purposes will be in substantially the forms appended hereto in Appendix E-1 - "PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE SERIES 2010-A BONDS AND SERIES 2010-C (TAXABLE) BUILD AMERICA BONDS" and Appendix E-2 - "PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE SERIES 2010-B BONDS."

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

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

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

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

TAX MATTERS

SERIES 2010-A BONDS AND SERIES 2010-B BONDS

In the opinion of Special Tax Counsel, based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the Series 2010-A Bonds and the Series 2010-B 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"), Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code") and Section 103 of the 1986 Code. Special Tax Counsel is of the further opinion that interest on the Series 2010-A Bonds and the Series 2010-B Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes. Special Tax Counsel expresses no opinion as to whether some or all interest on the Series 2010-A Bonds and the Series 2010-B Bonds 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 2010-A Bonds and the Series 2010-B Bonds and the due authorization and issuance of these Bonds. Complete copies of the proposed forms of opinions of Special Tax Counsel is set forth in Appendix E-1 - "PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE SERIES 2010-A BONDS AND SERIES 2010-C (TAXABLE) BUILD AMERICA BONDS" and Appendix E-2 – "PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE SERIES 2010-B BONDS."

To the extent the issue price of any maturity of the Series 2010-A Bonds or the Series 2010-B Bonds is less than the amount to be paid at maturity of such Series 2010-A Bonds or the Series 2010-B Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Series 2010-A Bonds or the Series 2010-B 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 2010-A Bonds or the Series 2010-B 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 2010-A Bonds or the Series 2010-B Bonds is the first price at which a substantial amount of such maturity of the Series 2010-A Bonds or the Series 2010-B 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 2010-A Bonds or the Series 2010-B 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 2010-A Bonds or the Series 2010-B Bonds to determine taxable gain or loss upon disposition (including sale, redemption, or payment on maturity) of such Series 2010-A Bonds or the Series 2010-B Bonds. Beneficial Owners of the Series 2010-A Bonds or the Series 2010-B Bonds should consult their own tax advisors with respect to the tax consequences of ownership of Series 2010-A Bonds or the Series 2010-B Bonds with original issue discount, including the treatment of Beneficial Owners who do not purchase such Series 2010-A Bonds or the Series 2010-B Bonds in the original offering to the public at the first price at which a substantial amount of such Series 2010-A Bonds or the Series 2010-B Bonds is sold to the public.

Series 2010-A Bonds and the Series 2010-B 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 Beneficial Owner's basis in a Premium Bond, will be reduced by the amount of amortizable bond premium properly allocable to such Beneficial Owner. 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, the 1954 Code and the 1986 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 2010-A Bonds and the Series 2010-B Bonds. Energy Northwest and Bonneville have made certain representations and covenanted to comply with certain restrictions designed to ensure that interest on the Series 2010-A Bonds and the Series 2010-B 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 2010-A Bonds and the Series 2010-B Bonds being included in gross income for federal income tax purposes, possibly from the date of original issuance of the Series 2010-A Bonds and the Series 2010-B 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)), or any other matters coming to the attention of Special Tax Counsel after the date of issuance of the Series 2010-A Bonds and the Series 2010-B Bonds may adversely affect the value of, or the tax status of, interest on the Series 2010-A Bonds and the Series 2010-B Bonds. Accordingly, the opinion of Special Tax Counsel is not intended to, and may not, be relied upon in connection with any such actions, events or matters.

Although Special Tax Counsel is of the opinion that interest on the Series 2010-A Bonds and the Series 2010-B Bonds is excluded from gross income for federal income tax purposes, the ownership or disposition of, or the accrual or receipt of interest on, the Series 2010-A Bonds or the Series 2010-B Bonds may otherwise affect a Beneficial Owner's federal, state or local tax liability. The nature and extent of these other tax consequences depends 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.

Future legislative proposals, if enacted into law, clarification of the 1954 Code, the 1986 Act, or the 1986 Code or court decisions may cause interest on the Series 2010-A Bonds or the Series 2010-B Bonds to be subject, directly or indirectly, to federal income taxation, to be subject to or exempted from state 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 legislative proposals or clarification of the 1954 Code, the 1986 Act, or the 1986 Code or court decisions may also affect the market price for, or marketability of, the Series 2010-A Bonds or the Series 2010-B Bonds. Prospective purchasers of the Series 2010-A Bonds or the Series 2010-B Bonds should consult their own tax advisors regarding any pending or proposed federal or state tax legislation, regulations or litigation as to which Special Tax Counsel expresses no opinion.

The opinion of Special Tax Counsel is based on current legal authority, covers certain matters not directly addressed by such authorities, and represents Special Tax Counsel's judgment as to the proper treatment of the Series 2010-A Bonds or the Series 2010-B Bonds for federal income tax purposes. It is not binding on the IRS or the courts. Furthermore, Special Tax Counsel cannot give and has not given any opinion or assurance about the future activities of Energy Northwest or Bonneville, or about the effect of future changes in the 1986 Act, the 1954 Code, the 1986 Code or the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. Energy Northwest and Bonneville have covenanted, however, to comply with applicable requirements of the 1986 Act, the 1954 Code and the 1986 Code.

Special Tax Counsel's engagement with respect to the Series 2010-A Bonds and the Series 2010-B Bonds ends with the issuance of the Series 2010-A Bonds and the Series 2010-B 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 2010-A Bonds and the Series 2010-B 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 2010-A Bonds or the Series 2010-B Bonds for audit, or the course or result of such audit, or an audit of bonds presenting similar tax issues may affect the market price for, or the marketability of, the Series 2010-A Bonds or the Series 2010-B Bonds, and may cause Energy Northwest, Bonneville or the Beneficial Owners to incur significant expense.

SERIES 2010-C (TAXABLE) BUILD AMERICA BONDS

In the opinion of Special Tax Counsel, based upon an analysis of existing laws, regulations, rulings and court decisions, interest on the Series 2010-C (Taxable) Build America Bonds is not excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act, Section 103 of the 1954 Code, or Section 103 of the 1986 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 2010-C (Taxable) Build America Bonds.

CIRCULAR 230 DISCLAIMER

Investors are urged to obtain independent tax advice regarding the Series 2010-C (Taxable) Build America Bonds based upon their particular circumstances. The tax discussion above regarding the Series 2010-C (Taxable) Build America Bonds was not intended or written to be used, and cannot be used, for the purposes of avoiding taxpayer penalties. The advice was written to support the promotion or marketing of the Series 2010-C (Taxable) Build America Bonds.

ERISA CONSIDERATION

The Employees Retirement Income Security Act of 1974, as amended ("ERISA"), and the Code generally prohibit certain transactions between a qualified employee benefit plan under ERISA or tax-qualified retirement plans and individual retirement accounts under the Code (collectively, the "Plans") and persons who, with respect to a Plan, are fiduciaries or other "parties in interest" within the meaning of ERISA or "disqualified persons" within the meaning of the Code. All fiduciaries of Plans should consult their own tax advisors with respect to the consequences of any investment in the Series 2010-C (Taxable) Build America Bonds.

RATINGS

Moody's Investors Service ("Moody's"), Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P") and Fitch, Inc. ("Fitch") have assigned the 2010 Bonds the ratings of Aaa, AA and AA, respectively. Ratings were applied for by Energy Northwest and certain information was supplied by Energy Northwest and Bonneville to such rating agencies to be considered in evaluating the 2010 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 2010 Bonds.

UNDERWRITING

The Underwriters have jointly and severally agreed, subject to certain conditions, to purchase the 2010 Bonds from Energy Northwest and to make a bona fide public offering of such 2010 Bonds at not in excess of the public offering prices set forth on the inside cover pages of this Official Statement. Aggregate underwriters' compensation under the bond purchase contract for the 2010-A Bonds and 2010-C (Taxable) Build America Bonds is $2,283,175. Aggregate underwriters' compensation under the bond purchase contract for the 2010-B Bonds is $210,315. The Underwriters' obligations are subject to certain conditions precedent contained in the bond purchase contracts and they will be obligated to purchase all of such 2010 Bonds being sold under the applicable bond purchase contract if any such 2010 Bonds are purchased. The 2010 Bonds may be offered and sold to certain dealers, banks and others (including underwriters and other dealers depositing such 2010 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 2010 Bonds.

Citigroup Inc., parent company of Citigroup Global Markets Inc., one of the underwriters of the 2010 Bonds, has informed Energy Northwest and Bonneville that it has entered into a retail brokerage joint venture with Morgan Stanley. As part of the joint venture, Citigroup Global Markets Inc. will distribute municipal securities to retail investors through the financial advisor network of new broker-dealer, Morgan Stanley Smith Barney LLC. This distribution arrangement became effective on June 1, 2009. As part of this arrangement, Citigroup Global Markets Inc. will compensate Morgan Stanley Smith Barney LLC for its selling efforts with respect to the 2010 Bonds.

J.P. Morgan Securities Inc., one of the underwriters of the 2010 Bonds, has informed Energy Northwest and Bonneville that it has entered into an agreement (the "Distribution Agreement") with UBS Financial Services Inc. for the retail distribution of certain municipal securities offerings, including the 2010 Bonds, at the original issue prices. Pursuant to the Distribution Agreement, if applicable for this transaction, J.P. Morgan Securities Inc. will share a portion of its underwriting compensation with respect to the 2010 Bonds with UBS Financial Services Inc.

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 dates of delivery of the 2010 Bonds, for the benefit of the owners and beneficial owners of the 2010 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 2010 Bonds, if material. Energy Northwest Annual Information is to be provided not later than December 31 of each year, commencing December 31, 2010. The Bonneville Annual Information is to be provided not later than March 31 of each year, commencing March 31, 2011. The Annual Information and notices of aforesaid enumerated events will be filed by Energy Northwest with the Municipal Securities Rulemaking Board (the "MSRB"). Currently, the information filed with the MSRB is available to the public without charge through its Electronic Municipal Market Access system ("EMMA"). 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. There have been several state initiatives involving energy issues, including a recent one requiring certain electric utilities to obtain a percentage of their electricity from renewable resources.

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 2010 Bonds, the basic agreements securing the 2010 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 2010 Bonds is to be construed as a contract with the holders of such Series of 2010 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/ Sid W. Morrison
Chairman, Executive Board

By: /s/ John Irvan
Authorized Officer

[THIS PAGE INTENTIONALLY LEFT BLANK]

APPENDIX A

BONNEVILLE POWER ADMINISTRATION

TABLE OF CONTENTS

	PAGE
GENERAL	A-3
CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE	A-5
Power Loads and Related Contracts and Power Rates through Fiscal Year 2011	A-5
Power Sales and Related Arrangements in the Period after Fiscal Year 2011	A-7
Fiscal Year 2009 Financial Results	A-11
Fiscal Year 2010 Expectations	A-11
POWER SERVICES	A-11
Description of the Generation Resources of the Federal System	A-12
Bonneville's Power Trading Floor Activities	A-15
Customers and Other Power Contract Parties of Bonneville's Power Services	A-16
Certain Statutes and Other Matters Affecting Bonneville's Power Services	A-19
TRANSMISSION SERVICES	A-32
Bonneville's Federal Transmission System	A-33
Non-discriminatory Transmission Access and Separation of the Power Services and Transmission Services	A-34
Bonneville's Transmission and Ancillary Services Rates	A-36
Bonneville's Participation in a Regional Transmission Organization	A-36
MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES	A-37
Bonneville Ratemaking and Rates	A-37
Limitations on Suits against Bonneville	A-39
Laws Relating to Environmental Protection	A-39
Energy Policy Act of 2005	A-39
Other Applicable Laws	A-40
Columbia River Treaty	A-40
Proposals for Federal Legislation and Administrative Action Relating to Bonneville	A-40
Climate Change	A-41
BONNEVILLE FINANCIAL OPERATIONS	A-42
The Bonneville Fund	A-42
The Federal System Investment	A-42
Bonneville's Financial Plan	A-43
Increase in Bonneville's Authority to Borrow from the United States Treasury	A-43
Bonneville Borrowing Authority	A-43
Banking Relationship between the United States Treasury and Bonneville	A-44
Debt Optimization Program	A-44
Order in Which Bonneville's Costs Are Met	A-45
Direct Pay Agreements	A-46
Direct Funding of Federal System Operations and Maintenance Expense	A-47
Position Management and Derivative Instrument Activities and Policies	A-47
Historical Federal System Financial Data	A-48
Management Discussion of Operating Results	A-51
Statement of Non-Federal Project Debt Service Coverage	A-53
Management Discussion of Unaudited Results for the Three Months Ended December 31, 2009	A-55
BONNEVILLE LITIGATION	A-56
ESA Litigation	A-56
DSI Service ROD Litigation	A-57
Long-Term Regional Dialogue Contracts, Policies and Records of Decision	A-58
2002 Final Power Rates Challenge	A-59
Residential Exchange Program Litigation	A-60
Southern California Edison v. Bonneville Power Administration	A-61
Rates Litigation	A-62
Miscellaneous Litigation	A-62

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 February 25, 2010, furnished by the Issuer (the "Official Statement") with respect to its Project 1 Electric Revenue Refunding Bonds, Series 2010-A, Project 3 Electric Revenue Refunding Bonds, Series 2010-A, Project 1 Electric Revenue Refunding Bonds, Series 2010-B, Columbia Generating Station Electric Revenue Refunding Bonds, Series 2010-B, Project 3 Electric Revenue Refunding Bonds, Series 2010-B, and Columbia Generating Station Electric Revenue Bonds, Series 2010-C (Taxable Build America Bonds) (collectively, the "Series 2010 Bonds"). (Project 1, Project 3 and the Columbia Generating Station are described in the Official Statement under "ENERGY NORTHWEST" and are referred to collectively in this Appendix A as the "Net Billed Projects.") Such information is not to be construed as a representation by or on behalf of the Issuer or the Underwriters. The Issuer has not independently verified such information and is relying on Bonneville's representation that such information is accurate and complete. At or prior to the time of delivery of the Series 2010 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 United States Department of Energy ("DOE"). Many of Bonneville's statutory authorities are vested in the Secretary of Energy, who appoints, and acts by and through, the Bonneville Power Administrator. Some other authorities are vested directly in the Bonneville Power Administrator.

Bonneville's primary enabling legislation includes the following Federal statutes: the Bonneville Project Act of 1937 (the "Project Act"); the Flood Control Act of 1944 (the "Flood Control Act"); Public Law 88-552 (the "Regional Preference Act"); the Federal Columbia River Transmission System Act of 1974 (the "Transmission System Act"); and the Northwest Electric Power Planning and Conservation Act of 1980 (the "Northwest Power Act"). Bonneville now markets electric power from 31 Federal hydroelectric projects, most of which are located in the Columbia River basin and all of which are owned and operated either by the United States Army Corps of Engineers ("Corps") or the United States Bureau of Reclamation ("Reclamation"). Bonneville also has acquired on a long-term basis and markets power from several non-Federally-owned and -operated projects, including the Columbia Generating Station, an operating nuclear generating station owned by Energy Northwest and having a rated capacity of approximately 1,150 megawatts. In addition, firm energy from transfers, exchanges, and purchases comprise the remaining portion of Bonneville's electric power resources. Not taking into account estimated power lost through the transmission of electricity from generation sites to load sites ("line losses"), Bonneville estimates that the foregoing projects and contracts have an expected aggregate output in the current operating year of about 11,078 annual average megawatts (defined below) under median water conditions and about 8,863 annual average megawatts under low water conditions. (Bonneville's "Operating Year" runs from August 1 through July 31. By contrast, its "Fiscal Year" runs from October 1 through September 30.) (Annual average megawatts are the number of megawatt-hours of electric energy used, transmitted or produced over the course of one year and each megawatt-hour is equal to 8,750 kilowatt-hours.)

Bonneville sells, purchases and exchanges firm power, seasonal surplus energy (which is also referred to as "secondary" or "non-firm" energy), peaking capacity and related power services. Bonneville also constructed, owns, operates, and maintains a high voltage transmission system (the "Federal Transmission System") comprising approximately three-fourths of the bulk transmission capacity in the Pacific Northwest. Bonneville uses this transmission capacity to deliver power to its customers and makes transmission capacity available to other utilities, owners of generation projects, and power marketers. Bonneville's primary customer service area is the Pacific Northwest region of the United States, encompassing the entirety of the states of Idaho, Oregon, and Washington, parts of western Montana, and small parts of western Wyoming, northern Nevada, northern Utah, and northern California (the "Pacific Northwest" or "Region"). Bonneville estimates that the population of the 300,000 square-mile service area is approximately 12 million people. Electric power sold by Bonneville accounts for more than one-third of the electric power consumed within the Region.

Bonneville markets a large portion of this power to over 125 publicly-owned and cooperatively-owned utilities ("Preference Customers") at wholesale, meaning for resale by the utilities to end-use consumers in the Region. Bonneville also has contracts to sell a comparatively small amount of power for direct consumption to a small number of companies ("Direct Service Industries" or "DSIs") located in the Region. Bonneville is also required by law to exchange power with qualifying utilities to meet their residential and small farm electric power loads within the Region. The operation of this program, referred to as the "Residential Exchange Program," has resulted and is expected to continue to result in substantial payments by Bonneville to the exchanging utilities. The primary participants in the Residential Exchange Program have been and are investor-owned utilities in the Region (the "Regional IOUs"), of which there are six. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

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 POWER SERVICES AND TRANSMISSION SERVICES—Bonneville Ratemaking and Rates." Bonneville may also issue and sell bonds to the United States Treasury and use the proceeds thereof to fund certain activities established under Federal law.

In 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 two business units: "Power Services" and "Transmission Services." See "TRANSMISSION SERVICES—Non-discriminatory Transmission Access and Separation of Power Services and Transmission Services."

Bonneville's cash receipts from all sources, including from both transmission and power services, must be deposited in the Bonneville Fund, which is a separate fund within the United States Treasury and which is available to pay Bonneville's costs. In accordance with the Transmission System Act, Bonneville must make expenditures from the Bonneville Fund as "shall have been included in annual budgets submitted to Congress, without further appropriation and without fiscal year limitation, but within such specific directives or limitations as may be included in appropriation acts, for any purpose necessary or appropriate to carry out the duties imposed upon [Bonneville] pursuant to law."

Bonneville is required to make certain payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal Columbia River Power System ("Federal System") other than payments to the United States Treasury for: (i) the repayment of the Federal investment in certain transmission facilities and the power generating facilities at Federally-owned hydroelectric projects in the Pacific Northwest; (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury; (iii) repayments of appropriated amounts to the Corps and Reclamation for certain costs allocated to power generation at Federally-owned hydroelectric projects in the Pacific Northwest; and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its payment responsibility to the United States Treasury of $845 million (including $234 million in principal payments in advance of due dates under the Debt Optimization Program as described in this Appendix A) in full and on time for Bonneville's fiscal year ended September 30, 2009 ("Fiscal Year 2009"). Bonneville has made all payments to the United States Treasury in full and on time since 1984. For more information, see "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met" and "—Debt Optimization Program."

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

CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE

Power Loads and Related Contracts and Power Rates through Fiscal Year 2011

Loads and Resource Expectations in Operating Years 2010 and 2011

Bonneville expects that, in aggregate, its total load obligations are about 8,510 annual average megawatts in Operating Year 2010, and will be about 8,461 annual average megawatts in Operating Year 2011. Of these loads: (i) the aggregate of Preference Customer, Federal agency, and DSI loads are forecast to increase from 7,300 annual average megawatts in Operating Year 2010 to 7,316 annual average megawatts in Operating Year 2011, and (ii) other Bonneville exports and intra-regional contract obligations are forecast to decrease from about 1,211 annual average megawatts in Operating Year 2010 to about 1,144 annual average megawatts in Operating Year 2011. The decrease in overall load obligations in Operating Year 2011 is primarily due to the expiration of short-term Bonneville marketing contracts.

Bonneville estimates that the Federal System will be able to produce about 8,612 annual average megawatts in Operating Year 2010, decreasing to 8,291 annual average megawatts in Operating Year 2011, in each case under certain assumptions of low river flows and after taking into account power purchases and estimates of energy losses from transmitting power from generation sources to loads. Bonneville's Federal System generation estimates for each year include various assumptions, including assumptions about refueling or other scheduled outages that are planned for the Columbia Generating Station. (Bonneville typically assumes that the Columbia Generating Station will have scheduled refueling outages every other year and that its output will be about 1,030 annual average megawatts in non-refueling years and about 878 annual average megawatts in refueling years. However, for Operating Year 2011 Bonneville is anticipating a planned, extended maintenance outage at the Columbia Generating Station in Operating Year 2011, which is expected to reduce output to about 785 annual average megawatts in such year.) In addition, Bonneville's current analysis of Federal System generating resources includes non-project-specific power purchases from power marketers and utilities and certain contract purchases that are tied to specific non-Federal generating resources. The decrease in the Federal System resource estimate in Operating Year 2011 is mainly due to the scheduled extended Columbia Generating Station maintenance and refueling outage and the expiration of several Bonneville marketing purchase contracts. See "POWER SERVICES—Description of the Generation Resources of the Federal System."

Given the foregoing expected resources and loads, Bonneville now anticipates that it has an energy surplus of 102 annual average megawatts in Operating Year 2010 and will have a projected deficit of approximately 170 annual average megawatts in Operating Year 2011.

Given the amount of Federal System generation and expected availability of hydro-generation in most low water assumptions, Bonneville believes that the foregoing near-term deficit is comparatively small and can be managed without substantial new long-term commitments for electric power supply. Federal System deficits, if any, from Operating Year 2011 through at least Operating Year 2014 will be met primarily through a combination of the following actions: (i) relying on the occurrence of seasonal surplus (secondary) energy, which is, primarily, hydroelectric generation produced from better-than-historically-low water conditions (referred to as "Critical Water," see "POWER SERVICES—Description of the Generation Resources of the Federal System—Federal Hydro Generation"); (ii) making short-term market power purchases; (iii) acquiring electric power from independent power producer-owned projects; (iv) employing cost-effective conservation programs and load management programs that reduce Bonneville's load obligations; and (v) purchasing hydro-storage to improve the timing of hydro-power generation or entering into power exchange agreements with other entities that need electric power at differing times than the Federal System so that power is returned to Bonneville at times when Bonneville's electric power demands are high. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region." In addition, Bonneville may enter into electric power-related financial agreements that do not involve physical delivery in order to address price risk in the purchase and sale of energy in an effort to assure that it has cost effective access to power to meet its commitments.

Preference Customer and Federal Agency Loads. Bonneville currently provides three basic types of power to Preference Customers, primarily to meet the customers' own requirements in the Region: (i) Block power, which is power provided in pre-determined amounts at pre-determined times to meet the customers' requirements, (ii) Requirements service, which is power provided as necessary to meet a customer's loads, and (iii) Slice of the System, which is a proportionate amount of power if, as, and when generated by the Federal System (a portion of the Slice product is sold as requirements power, to the extent that Federal System generation meets the Slice customers' loads, and a portion of the Slice product is sold as surplus power, to the extent that generation exceeds the Slice customers' loads). Requirements service may be either "Full Requirements" service, meaning that Bonneville is responsible for meeting all of the customer's electric power loads, or "Partial Requirements service," meaning that Bonneville is responsible for meeting all of the customer's electric power loads to the extent not met by electric power that the customer has otherwise committed to meeting its loads. All Slice and most Block power is currently sold together as a single integrated power product called "Slice/Block."

Under the foregoing agreements, as amended, Bonneville estimates that it will be obligated to provide roughly 7,300 to 7,316 annual average megawatts to meet Preference Customer, Federal agency, and Reclamation load obligations in Operating Years 2010 to 2011. For Operating Year 2010, about 1,618 annual average megawatts is sold as Slice of the System, about 1,880 annual average megawatts is in the form of Block service or the Block portion of Slice/Block service and the remainder is in the form of Full or Partial Requirements service. The actual amount of power sold by Bonneville under the Slice of the System contracts varies from year to year depending on actual generation. The Slice of the System component of 1,618 annual average megawatts reflects the firm power component of the Slice product. Slice of the System customers also receive what otherwise would be seasonal surplus (secondary) energy in amounts that depend on precipitation in the Columbia River basin and actual generation from Federal System resources.

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 140 annual average megawatts in Operating Year 2010, increasing to 144 annual average megawatts in Operating Year 2011.

DSI Loads. With respect to service to DSIs, Bonneville has no statutory obligation but is authorized to sell them power. Bonneville currently has in effect separate power sales agreements with two DSIs. Under these agreements, Bonneville sells 340.1 annual average megawatts in aggregate, delivered each hour of each day. Both sales are made at Bonneville's rate for DSI service, the Industrial Power (or, "IP") rate.

One sale provides for Bonneville to deliver 320 annual average megawatts to Alcoa, Inc. ("Alcoa"), an aluminum industry DSI, through an "Initial Period," which ends May 26, 2011, although the Initial Period can be extended for an additional year if Bonneville determines that the contract will provide equivalent benefits to Bonneville during the extension. A "Second Period" of five additional years will commence, if at all, immediately following the Initial Period, but only if the extension would be consistent with then-applicable Ninth Circuit Court precedent regarding Bonneville's service to DSIs, and Bonneville determines that the costs that it will incur to meet its obligations under the contract will not exceed certain specified cost caps.

The second DSI power sale involves the sale of 20.1 annual average megawatts to a non-aluminum-industry DSI, Port Townsend Paper Company ("Port Townsend"). The agreement runs through May 2011.

Bonneville's service to DSIs has been the subject of recent litigation. Prior to Bonneville's entry into the DSI agreements described immediately above, the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit Court"), which is a federal appeals court with limited original jurisdiction over many matters relating to Bonneville, issued two separate opinions that concluded that certain prior power sales by Bonneville to Alcoa were not consistent with Bonneville's governing laws. In January 2010, litigation was filed with regard to the Alcoa agreement. In February 2010, litigation was filed challenging Bonneville's entry into the Port Townsend agreement. See "BONNEVILLE LITIGATION—DSI Service ROD Litigation."

Rate Proposal for the 2010-2011 Rate Period

After a formal administrative process, Bonneville proposed power and transmission rates for the two fiscal years beginning October 1, 2009 (the "2010-2011 Rate Period"). In July 2009, Bonneville submitted the proposed rate and related records of decision (the "2010-2011 Final Power and Transmission Rate Proposal") to FERC for its review. FERC granted interim approval of the rates on September 28, 2009, pending final review.

To address various risks, the 2010-2011 Final Power and Transmission Rate Proposal continues the use of (i) "base rates" for Regional power sales that are set at levels Bonneville believes to be sufficient to yield a reasonably high probability of sufficient "modified net revenues" and (ii) a rate level adjustment mechanism (the "Cost Recovery Adjustment Clause," or "CRAC") that allows rate levels to be reset at the beginning of the first year of the rate period and one time in the middle of the two year rate period, in each case according to costs and revenues. The CRAC did not trigger for Fiscal Year 2010; therefore, power rates were not reset for the first year of the 2010-2011 Rate Period. "Modified net revenues" are net revenues after adjusting for the effects of the unrealized fair value of derivative instruments and certain non-Federal debt management actions. Bonneville believes that modified net revenues are a better reflection of Bonneville's financial results than standard accounting determinations of net revenues.

Bonneville is required by law to provide power sales service to Preference Customers for their loads in the Region at Bonneville's lowest, statutorily-designated, cost-based power rate class, the Priority Firm Rate ("PF Rate"). When compared to PF Rate levels for Full Requirements service in the final year of the prior power rate period (the "2007-2009 Power Rate Period"), the average PF Rate levels for Full Requirements service to Preference Customers as adopted in the 2010-2011 Final Power and Transmission Rate Proposal increased by approximately seven percent, from approximately $26.90 per megawatt hour to $28.77 per megawatt hour (excluding transmission charges). These rate level estimates reflect the rate level determinations only and do not incorporate bill credits or electronic funds payments to Preference Customers to remedy the effects of Bonneville's past overpayment of Residential Exchange Program benefits. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2010 through 2011." The proposed increase in PF Rates reflects Bonneville's expectations and assumptions when developing the rate proposal for increased operations and maintenance costs, including at Columbia Generating Station, increased fish and wildlife costs, and increased operations and maintenance expense at the Federally-owned hydro-projects of the Federal System.

Under the 2010-2011 Final Power and Transmission Rate Proposal, Bonneville also expects that the aggregate Residential Exchange Program benefits will average about $266 million per year during the two-year rate period. Of this average annual aggregate amount, $255 million per year will be for residential and small farm customers of the Regional IOUs, with the remainder being paid to certain Preference Customers. Actual payments by Bonneville of Residential Exchange Program benefits to Regional IOUs will be offset by $82 million per year on average under Bonneville's program to recoup past overpayments of Residential Exchange Program benefits to Regional IOUs. Bonneville recoups the past overpayments from Regional IOUs by means of contractual offsets to future Residential Exchange Program benefits payments to Regional IOUs. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

Under the 2010-2011 Final Power and Transmission Rate Proposal, the IP Rate for DSI service is proposed to be $34.60 per megawatt hour (excluding transmission charges). The IP Rate is a rate for power that is provided to DSIs in the same amount all hours of all days.

Bonneville expects to begin conducting workshops in March 2010 related to the upcoming combined power and transmission rate case for the two fiscal years beginning October 1, 2011 (the "2012-2013 Rate Period"). Bonneville plans to release the initial proposal for the 2012-2013 Rate Period in November 2010 and submit the final proposal to FERC by the end of July 2011.

Power Sales and Related Arrangements in the Period after Fiscal Year 2011

All of Bonneville's power sales agreements under which Bonneville currently sells power or provides benefits to Regional Preference Customers will expire at the end of Fiscal Year 2011. In anticipation of the impending expiration of these contracts, and in hopes of concurrently shaping Bonneville's long-term Residential Exchange Program obligations, Bonneville and its customers engaged in a "Regional Dialogue," a broad-based discussion among Bonneville customers and other parties about Bonneville's long-term role in meeting Regional power needs. The second phase of the Regional Dialogue addressed, as the basis for new long-term power sales and related contracts, how Bonneville will implement a policy direction of limiting its power sales, at the lowest cost-based rates consistent with sound business principles, to roughly the output of existing Federal System generating resources in the period after Fiscal Year 2011. In the past, when Bonneville augmented its own resources with market or other generating resources, the costs of these typically more expensive purchases were melded in with the Federal System's very low, embedded cost power, creating power rates that masked both the real value of Federal System power and the incremental costs of meeting load growth.

Power Sales to Preference Customers

In December 2008, Bonneville and each of its Preference Customers entered into contracts for power service by Bonneville from Fiscal Year 2012 through Fiscal Year 2028 ("New Long-Term Preference Contracts"). There are two basic types of power service that Bonneville will provide under the New Long-Term Preference Contracts: (i) Slice/Block service, which is an integrated power product combining Slice and Block services similar to those Bonneville currently provides to certain Preference Customers, and (ii) Load Following service, under which the equivalent of Full Requirements or Partial Requirements service can be obtained from Bonneville. Under Slice/Block, Bonneville commits to provide a Slice of the System product together with fixed blocks of power at designated times. For a description of Slice, Block, and Requirements service, see "—Power Loads and Related Contracts and Power Rates through Fiscal Year 2011—Loads and Resource Expectations in Operating Years 2010 and 2011—Preference Customer and Federal Agency Loads." Under Load Following service, Bonneville provides the actual power requirements of the related customer after taking into account generating resources, if any, that the customer has identified, consistent with certain contract conditions, as being used to meet its loads. A customer's net requirements loads, in general, are the customer's loads within its service territory that are served other than with the non-Federal System resources designated by the customer as being used to serve the customer's native loads.

<u>Types of Service Chosen by Preference Customers</u>. Seventeen separate Preference Customers have elected to purchase Slice/Block as the type of service they will receive under their New Long-Term Preference Contracts. The remaining Preference Customers have elected to take Load Following service. In aggregate, sales of the Slice component of Slice/Block under the New Long-Term Preference Contracts represent about 27.0 percent of Federal System generation. By contrast, Bonneville currently sells about 22.6 percent of the Federal System generation as Slice.

Preliminary forecasts for Fiscal Year 2012 indicate that loads met under Load Following service will be about 3,400 annual average megawatts and loads met by the Block portion of Slice/Block service will be about 2,000 annual average megawatts. Bonneville expects that the Slice portion of Slice/Block service will be about 2,000 average annual megawatts. The forecasts reflect an attempt to predict actual loads that will be met under the specified type of service, which loads vary with weather, economic and other conditions, and in the case of Slice, the actual generation of the Federal System.

All of the New Long-Term Preference Contracts for Load Following service subject the customers to a payment commitment under which they are required to pay for power tendered by Bonneville to the extent of the customer's net requirements. If a customer's loads decline, however, the customer's purchase obligation from Bonneville is reduced commensurately. Conversely, if a customer's net requirements (as opposed to loads) decline due to reductions in the customer's own loads, the resulting excess power may not be purchased by the customer and remarketed. For Slice/Block, the customers' obligations and rights to purchase power are similarly capped by their loads, although in the case of the Slice portion of Slice/Block, the cap only relates to that portion of their Slice purchases that is to be made in respect of their net requirements.

<u>Amount of Power Available at Tier 1 PF Rates</u>. The contract provisions, in concert with the Tiered Rate Methodology (see "—Tiered Rates Methodology," below) will restrict the power that Preference Customers may purchase in aggregate at "Tier 1 PF Rates" in general to an amount equal to the generating output of the currently existing Federal System. (Tier 1 PF Rates, which will be Bonneville's lowest cost rates, will be used for Load Following service and Slice/Block service. While Slice/Block and Load Following Service will each be provided under Tier 1 PF Rates, the specific rate levels applicable to each such service will differ, reflecting Bonneville's differing rate design and specific costs to provide the respective types of service.) Power for "Tier 2 Loads," meaning any net requirements load placed on Bonneville by a customer in excess of its right to purchase at Tier 1 PF Rates, will be sold at "Tier 2 PF Rates" that recover the cost to Bonneville of acquiring the incremental electric power needed to meet Tier 2 Loads. Bonneville expects that Tier 1 PF Rates will be lower than Tier 2 PF Rates because the imbedded cost of power of the existing Federal System, which will be allocated for recovery in Tier PF 1 Rates, will likely be lower than the cost of new resources obtained to meet Tier 2 Loads and allocated for recovery in Tier 2 PF Rates.

The amount of power to be purchased at Tier 1 PF Rates ("Tier 1 Power") may be expanded in certain limited circumstances. These include: (i) an amount of up to 300 annual average megawatts in augmentation purchases of electric power to address specific issues related to the transition to the new contracts, including intervening load growth until Fiscal Year 2012, (ii) up to 250 average megawatts, if necessary, for new Preference Customers (to address the possible formation of new Preference Customers, Bonneville has also agreed to limit the aggregate amount of power that such new Preference Customers purchase at Tier 1 PF Rates to 250 annual average megawatts through Fiscal Year 2028), and (iii) 70 annual average megawatts for a potential load at a site operated by the DOE. In addition, Bonneville's obligation to sell power at Tier 1 PF Rates will be reduced if and to the extent that related existing Federal System resources, including the Columbia Generating Station, decline in capability.

Each Preference Customer's right to purchase power at Tier 1 PF Rates will be determined based in part on the proportion that its net requirement bears to all Preference Customers' net requirements placed on Bonneville in Fiscal Year 2010, or, in certain cases, in a fiscal year prior to Fiscal Year 2010. In view of declines in the loads of some Preference Customers arising from the current economic recession and the expectation that much of the decline in loads will be recovered as the recession ends, Bonneville has agreed that a Preference Customer may elect to establish the amount of power it may purchase at Tier 1 PF Rates based upon the greatest net requirements it had in any of the three fiscal years before Fiscal Year 2010. Thus, a customer that had its highest net requirements in Fiscal Year 2007 may and, given the expected low cost of power at Tier 1 PF Rates, presumably will, elect to use such alternative fiscal year, thereby maximizing the amount of power it may purchase at Tier 1 PF Rates. Furthermore, because a Preference Customer's right to purchase power at Tier 1 PF Rates is proportionate based on its net requirements relative to all Preference Customers' net requirements, the exact proportion of the amount of power at Tier 1 PF Rates that each Preference Customer has access to will likely adjust slightly over time if and when Bonneville begins meeting the loads of new Preference Customers.

Bonneville currently assumes that aggregate Tier 1 commitments will at least equal the existing Federal System capability. It is possible that the amount of intervening load growth between December 2009 and October 2011, which would increase Tier 1 loads, could be relatively small and that the resulting amount of the Tier 1 augmentation described above could be less than 300 annual average megawatts.

Certain parties have expressed an interest in forming two separate utilities that could qualify as new Preference Customers. Bonneville is unable to predict whether the possible utilities will commence operation or become Preference Customers.

Tiered Rates Methodology. A key element of the New Long-Term Preference Contracts is the establishment of the basic features of a long-term rate design methodology ("Tiered Rates Methodology") for periodically determining the applicable PF Rates throughout the term of the new contracts. Bonneville expects to employ two-year rate periods during the term of the New Long-Term Preference Contracts. In 2008, Bonneville developed a final Tiered Rates Methodology and submitted it to FERC seeking a declaratory order that the methodology does not compromise Bonneville's ability to recover its costs. The Tiered Rates Methodology seeks primarily to define the costs that will be allocated to Tier 1 PF Rates and Tier 2 PF Rates. Under the Tiered Rates Methodology, Tier 2 PF Rates recover the costs of meeting loads at Tier 2 rates while Tier 1 PF Rates recover the costs of the Federal System generating facilities including the costs assigned to power rates for the Net Billed Projects (some Net Billed Project debt service costs are assigned to be recovered in transmission rates), Federal System fish and wildlife costs, electric power conservation programs, transitional power augmentation as discussed above, power benefits to be provided to DSIs (if any), and Residential Exchange Program benefits. Under the Tiered Rates Methodology, revenues from Bonneville's sales of secondary energy derived from Tier 1 Federal System resources are allocated to non-Slice Tier 1 PF Rates.

Bonneville believes that a reliable rate methodology in this regard must be specified to effectuate the New Long-Term Preference Contracts. Accordingly, the contracts include provisions tying the associated power sales to the legal validity of the Tiered Rates Methodology. Certain aspects of the Tiered Rates Methodology have been challenged in litigation. See "BONNEVILLE LITIGATION—Long-Term Regional Dialogue Contracts, Policies and Records of Decision." Bonneville's request for a declaratory order remains pending with FERC.

Bonneville's Obligation under the New Long-Term Preference Contracts to Meet or to Contribute to Meeting Preference Customers' Load Growth. As noted above, power for "Tier 2 Loads," meaning any net requirements load placed on Bonneville by a customer in excess of its right to purchase at Tier 1 PF Rates, will be sold at Tier 2 PF Rates that seek to recover the cost to Bonneville of acquiring the electric power needed to meet such Tier 2 loads. For all Preference Customers purchasing power from Bonneville to meet Tier 2 loads, such purchases will be integrated with purchases of power for Tier 1 loads into a single power purchase, although the purchase of power for Bonneville for Tier 2 loads will be made on a take-or-pay basis.

Bonneville offered several approaches for Preference Customers to define the extent, if any, to which Bonneville will meet their Tier 2 Loads. Bonneville provided the customers the ability to rely entirely on Bonneville to meet all such loads throughout the term of the contracts. Bonneville also allowed the customers to rely on Bonneville, with specified notice to Bonneville, to meet all or a portion of their Tier 2 Loads for defined multi-year periods through the term of the agreements. Under this approach, a participating Preference Customer could require Bonneville to meet none, all or designated portions of the customer's Tier 2 Loads. In addition, Bonneville will allow customers to make all or portions of their Tier 2 purchases from specified resources or resource pools obtained by Bonneville. This is expected to assist such customers in meeting renewable resource or other requirements or goals.

Under the New Long-Term Preference Contracts, Preference Customers were required on or before November 1, 2009, to commit to the amount of Tier 2 Loads they would place on Bonneville in the three fiscal years commencing with

Fiscal Year 2012. Under these notifications, Bonneville estimates that it will be obligated to meet an estimated 20 annual average megawatts of Tier 2 Loads beginning in Fiscal Year 2012, increasing to 56.4 annual average megawatts in Fiscal Year 2014. Bonneville is unable to predict with a reasonable level of confidence the amount of Tier 2 Loads Preference Customers will place on Bonneville after Fiscal Year 2014. Under the New Long-Term Preference Contracts, Preference Customers are required on or before September 30, 2011, to commit to the amount of Tier 2 Loads they will place on Bonneville in the five fiscal years commencing with Fiscal Year 2015. Similar Tier 2 elections and advance notice to Bonneville are required in the five fiscal years beginning with Fiscal Year 2020, and the four fiscal years beginning with Fiscal Year 2025.

There is substantial uncertainty in forecasting long-term loads, and Bonneville's strategy for meeting any such loads placed on Bonneville will take such uncertainty into account. Bonneville prepared a draft "Resource Program" in September 2009, and expects to issue the final Resource Program in September 2010. The program will systematically evaluate Bonneville's need for new power resources in light of changes in demands on existing system resources. These needs may arise from Tier 1 Load expansion, Tier 2 Loads and load growth, long-term DSI power sale commitments (if any), and evolving transmission system requirements. The final Resource Program will also evaluate the means by which Bonneville will meet its electric power needs. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Bonneville's Resource Program and Bonneville's Resource Strategies for the Post-2011 Period."

While almost all Residential Exchange Program benefits are paid to Regional IOUs, Preference Customers may also qualify for such benefits, as provided in the Northwest Power Act. The New Long-Term Preference Contracts include provisions under which Preference Customers may obtain Residential Exchange Program benefits after Fiscal Year 2011 on a limited basis. A Preference Customer may receive such benefits only if the average system cost of its generating resources (to the extent such resources are actually used in Fiscal Year 2010 to meet the Customer's own loads) exceeds the Residential Exchange Rate (defined below). In effect, a Preference Customer will not be able to obtain Residential Exchange Program benefits for the cost of new resources it adds after Fiscal Year 2010 to meet its loads. This contract term is important to preserve the Tiered Rates Methodology, whereby the costs a Preference Customer bears to meet new loads are met by the Preference Customer, either on its own or through Bonneville but at Tier 2 PF Rates. Otherwise, a Preference Customer could obtain new resources and receive Residential Exchange Program benefits for such new resources, with most if not all of the cost of such benefits being allocated to recovery in Tier 1 PF Rates. This would contradict the goal of the Tiered Rates Methodology, which is to insulate Tier 1 PF Rates from the costs of new generation resources to meet Preference Customers' load growth. A Preference Customer has filed litigation challenging these and related terms. See "BONNEVILLE LITIGATION—Long-Term Regional Dialogue Contracts, Policies and Records of Decision."

Residential Exchange Program and Other Arrangements with Regional IOUs after Fiscal Year 2011

Bonneville has entered into long-term Residential Purchase and Sale Agreements ("Long-Term RPSA") for Fiscal Year 2012 through Fiscal Year 2028 with three of the Regional IOUs and expects to enter into Long-Term RPSAs with at least two of the three other Regional IOUs prior to Fiscal Year 2012. Under these agreements, Residential Exchange Program benefits are provided pursuant to the Residential Exchange Program provisions of the Northwest Power Act. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

Bonneville is also required by law to offer to sell power to meet the Regional IOUs' net requirements loads in the Region. In late summer 2008, Bonneville offered Long-Term Regional Dialogue requirements contracts to the Region's IOUs. Four of the six Regional IOUs executed contracts. In November 2009, all four of the Regional IOUs that executed long-term contracts elected not to purchase requirements power from Bonneville until at least Fiscal Year 2020. At the end of Fiscal Year 2016, the utilities will elect whether or not to purchase requirements power for Fiscal Years 2020 through 2028. Any requirements power provided by Bonneville under these contracts would be priced at the "New Resources Rate." This rate would in effect reflect the marginal cost to Bonneville of acquiring power to meet the loads plus certain other costs. Bonneville believes that it is unlikely, unless circumstances change, that Regional IOUs will place substantial loads, if any, on Bonneville under the Long-Term Regional Dialogue contracts because (i) there is no reason to expect that Bonneville's cost to meet such loads, as reflected in the New Resources Rate, would be significantly lower than the Regional IOUs' cost to meet such loads, (ii) the Regional IOUs are financially motivated to make investments in new generating facilities in order to obtain shareholder returns, (iii) most of the Regional IOUs have state-mandated renewable resource purchase obligations and would have to be assured that such obligations are addressed in any power purchases from Bonneville, and (iv) the Regional IOUs would not be able to control directly the terms and costs of the new resources Bonneville would obtain to meet the loads.

Power Sales to DSIs after Fiscal Year 2011

Coincident with developing the Regional Dialogue Contracts and Tiered Rates Methodology, Bonneville proposed to provide DSIs with economic benefits from low-cost Federal System power, either in the form of financial payments or in low cost physically-delivered electric power. Bonneville also proposed to recover the net cost of any of DSI service from Tier 1 PF Rates.

Bonneville interprets recent rulings by the Ninth Circuit Court to require that any decision to provide DSI service be supported by an analysis demonstrating that the sale(s) will result in positive benefits to Bonneville. For this reason, Bonneville is unable to predict the level of service that it may make available to DSIs on a long-term basis.

Fiscal Year 2009 Financial Results

In Fiscal Year 2009, Bonneville made its scheduled United States Treasury payments on time and in full for the 26th consecutive year. Bonneville finished the fiscal year with financial reserves of $1.363 billion, which is a decline of about 17 percent from the prior fiscal year. In addition, Bonneville's modified net revenues declined $344 million from modified net revenues of positive $157 million in Fiscal Year 2008 to negative $187 million in Fiscal Year 2009. The decline in reserves and modified net revenues resulted from a number of factors primarily relating to increased expense and reduced revenues from sales of seasonal surplus (secondary) energy because of lower prices and lower hydroelectric generation caused by lower water conditions. Bonneville believes that modified net revenues are a better reflection of Bonneville's financial results than standard accounting determinations of net revenues. See "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results—Fiscal Year 2009."

Fiscal Year 2010 Expectations

Current analyses prepared outside of Bonneville but relied on by Bonneville indicate a water supply forecast for the Columbia River basin, as of February 25, 2010, of 69 percent of the 30-year average for Fiscal Year 2010, as measured in terms of millions of acre feet of water. Historically, runoff amounts are determined to a great degree by late fall, winter, and early spring precipitation conditions in the Pacific Northwest and British Columbia. Current forecasts of runoff are preliminary indicators only and actual results could differ substantially from the projections.

Bonneville expects that the lower-than-average hydro-conditions in Fiscal Year 2010 will adversely affect Bonneville's net revenues with respect to Power Services in such year. In addition, lower-than-expected prices for secondary energy will also adversely affect net revenues with respect to Power Services. Bonneville expects that Power Services will not meet the projection of $114 million in modified net revenues in Fiscal Year 2010, as forecasted in Bonneville's Final 2010-2011 Power and Transmission Rate Proposal. As of January 26, 2010, Bonneville estimated that financial reserves of $1.363 billion as of the end of Fiscal Year 2009 will drop to approximately $1.089 billion at the end of Fiscal Year 2010. Financial reserves are composed of Bonneville cash, specials investments held in the Bonneville Fund, and deferred borrowing from the United States Treasury, which are affected by numerous factors including estimates of revenues and expenses for the year, increases or decreases in cash and cash equivalents related to the timing of collections and payments, capital expenditures, and principal and interest payments to the United States Treasury.

Hydro-conditions and market prices have deteriorated somewhat since the foregoing financial reserves estimate was developed. The foregoing estimates of fiscal year end financial reserves and net revenues are based on highly uncertain variables and are subject to change.

Based on reserve levels in the Bonneville Fund and forecasts of revenues and expenses as of the end of the first quarter of Fiscal Year 2010, Bonneville believes that there is a high probability that Bonneville will meet its Fiscal Year 2010 United States Treasury payment responsibilities on time and in full. Such belief is based on information and conditions early in Bonneville's current fiscal year, which are subject to change.

POWER SERVICES

Bonneville's Power Services is responsible for marketing the electric power of the Federal System, providing oversight to electric power resources of the Federal System, and purchasing and exchanging Federal System power. Power Services was responsible for about $2.1 billion in revenues, or 76 percent, of Bonneville's total revenues from external customers (and excluding revenues otherwise arising from inter-functional transactions between Bonneville's Transmission Services and Power Services) in Fiscal Year 2009.

Description of the Generation Resources of the Federal System

Generation

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

Bonneville defines "firm power" as electric power that is continuously available from the Federal System during adverse water conditions to meet Federal System firm loads. The amount of firm power that can be produced by the Federal System and marketed by Bonneville is based on "critical water" assumptions, *i.e.*, a low-water period on record for the Columbia River basin. Firm power can be relied on to be available when needed. Firm power has two components: peaking capacity (measured in megawatts) and firm energy (measured in average megawatts). Peaking capacity refers to the generating capability to serve particular loads at the time such power is demanded. This is distinguishable from firm energy, which refers to an amount of electric energy that is reliably generated over a period of time. Bonneville has estimated that in Operating Year 2010 (August 1, 2009 through July 31, 2010), the total Federal System would be capable of producing about 8,612 annual average megawatts of firm energy under low water conditions and not accounting for line losses. This generation includes about 735 annual average megawatts of firm energy from transfers and exchanges and about 115 annual average megawatts from renewable and non-utility generation projects. See the following table, "Operating Federal System Projects for Operating Year 2010."

Federal Hydro Generation

The share of hydropower from Federally-owned hydroelectric projects for Operating Year 2010 is estimated to be approximately 79 percent of Bonneville's total firm power supply. Bonneville also has acquired a small amount of power from non-Federally-owned hydroelectric projects. Bonneville's large resource base of hydropower results in operating and planning characteristics that differ from those of major utilities that lack a substantial hydropower base. See the table entitled "Operating Federal System Projects for Operating Year 2010."

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 (secondary) energy, described below, that are based on certainty of occurrence.

The Federal System is primarily a hydropower system in which the peaking capacity exceeds Federal System peaking loads and power reserve requirements in most months and in most water years. Bonneville estimates that in most months of an operating year and under most water and load conditions its peaking capacity, for long-term planning purposes, will meet or exceed its requirements for the next ten years. Bonneville expects this excess of peaking capacity to persist, because as Bonneville acquires or augments to balance annual and seasonal firm energy needs with new resources or purchases, these resource additions will also contribute more peaking capacity. At this time, Bonneville's resource planning focuses primarily on the need to develop sufficient firm energy resources to meet firm energy loads. In contrast, most utilities with coal-, gas-, oil- and nuclear-based generating systems must focus their resource planning on having enough peaking capacity to meet peak loads. As additional non-power requirements are placed on the Federal System hydroelectric operations and as peak load obligations grow, it may become necessary for Bonneville to plan for additional peaking capacity resources or purchases to meet peak loads.

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

In general, for long-term resource planning purposes Bonneville estimates the amount of electric power it will acquire to meet loads above the expected Federal System firm power generated under certain low water conditions, referred to as "Critical Water." 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 (secondary) 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 2010, the Federal System is estimated to generate seasonal surplus energy of 1,740 annual average megawatts, assuming average water conditions (median water flows). In years with high water conditions (high water flows) the amount of annual energy surplus could be as much as 2,940 annual average megawatts. In low water years, the amount of seasonal surplus energy generated by the Federal System could be quite small or not available at all.

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

These requirements change the shape, availability and timeliness of Federal hydropower to meet load. The information in the following table estimates the operation of the Federal System under the Pacific Northwest Coordination Agreement ("PNCA"). The PNCA defines the planning and operation of Bonneville, U.S. Pacific Northwest utilities and other parties with generating facilities within the Region's hydroelectric system. The hydro-regulation study incorporated measures, including but not limited to: (i) measures under the National Oceanographic and Atmospheric Administration Fisheries ("NOAA Fisheries") biological opinions relating to the operation of the Federal System on the Columbia River and Snake River and tributaries and related court-ordered operations; (ii) the United States Fish and Wildlife Service ("Fish and Wildlife Service") biological opinions relating to operation of certain Snake River and Columbia River and tributary dams; and (iii) operations described in the Council's Fish and Wildlife Program. These measures include increased flow augmentation for juvenile fish migration in the Snake and Columbia Rivers in the spring and summer, mandatory spill requirements at the Lower Snake and Columbia River dams to provide for non-turbine passage routes for juvenile fish migrants, and additional flows for Kootenai River white sturgeon in the spring. As new biological opinions and similar non-power requirements are introduced to the hydropower system, those changes will be reflected, as and when appropriate, in estimates of the availability of Federal hydropower under all water conditions. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

Other Power Resources and Contract Purchases

The balance of the Federal System includes, among other resources, nuclear power from the Columbia Generating Station, which has the largest capacity for energy production of the non-Federal resources. See Footnote 9 in the following table "Operating Federal System Projects for Operating Year 2010." In addition, Bonneville has a number of power purchase contracts that are not tied to specific generating resources. Bonneville projects that it will continue to have long-term contracts for transfers and exchanges that provide roughly 735 annual average megawatts.

Operating Federal System Projects for Operating Year 2010

In all years, the energy generating capability of the Federal System's hydroelectric projects depends upon the amount of water flowing through such facilities, the physical capacity of the facilities, stream-flow requirements pursuant to biological opinions, and other operating limitations. Bonneville utilizes a 70-year record of river flows based on the period from 1929-1998 for planning purposes. During this 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 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 2010, 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 2010(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 (Reclamation) Hydro Projects						
Grand Coulee incl. Pump Turbine	1941	33	6,192	2,876	2,444	1,866
Hungry Horse	1952	4	379	154	104	83
Other Reclamation Projects(6)		16	125	182	171	126
1. Total Reclamation Projects		53	6,696	3,212	2,719	2,075
United States Army Corps of Engineers (Corps) Hydro Projects						
Chief Joseph	1955	27	2,535	1,130	1,264	1,069
John Day	1968	16	2,484	1,182	1,089	796
The Dalles w/o Fishway(7)	1957	24	2,074	839	831	606
Bonneville	1938	20	1,052	594	565	407
McNary	1953	14	1,127	629	661	499
Lower Granite	1975	6	930	365	292	198
Lower Monumental	1969	6	923	382	318	197
Little Goose	1970	6	928	383	311	204
Ice Harbor	1961	6	693	225	236	171
Libby	1975	5	579	294	226	184
Dworshak	1974	3	445	285	203	149
Other Corps Projects(8)		20	235	334	300	250
2. Total Corps Projects		153	14,005	6,642	6,296	4,730
3. Total Reclamation and Corps Projects (line 1 + line 2)		**206**	**20,701**	**9,854**	**9,015**	**6,805**
Non-Federally-Owned Projects						
Columbia Generating Station(9)	1984	1	1,150	1,030	1,030	1,030
Other Non-Federal Hydro Projects(10)		7	23	62	45	40
Other Non-Federal Projects(11)		11	76	115	115	115
4. Total Non-Federally-Owned Projects		**19**	**1,249**	**1,207**	**1,190**	**1,185**
Federal Contract Purchases						
5. Total Bonneville Contract Purchases(12)		**n/a**	**1,004**	**873**	**873**	**873**
Total Federal System Resources						
6. Total Federal System Resources (line 3 + line 4 + line 5)		**225**	**22,954**	**11,934**	**11,078**	**8,863**

Source: Draft 2009 Pacific Northwest Loads and Resources Study, Bonneville, July 2009. Revised November 30, 2009.

(1) Operating Year 2010 is August 1, 2009 through July 31, 2010. Discrepancies from the figures portrayed in the "2009 Pacific Northwest Loads and Resources Study" are due to rounding.

(2) January capacity is the maximum generation to be produced under Low Water Flows in megawatts of capacity. January is a benchmark month for the system peaking capability because of the potential for high peak loads during January due to winter weather. Bonneville further reduces estimates of its hydro peaking capacity to reflect that the hydro system has more machine capacity in its generating units than fuel (river flows) available to operate all units on a continuous basis.

(3) Maximum energy capability is the estimated amount of hydro energy to be produced using High Water Flows for energy in average megawatts. The hydro-regulation study incorporates measures prescribed by the NOAA Fisheries biological opinions relating to the Columbia River and tributaries and court-ordered operations; the

Fish and Wildlife Service biological opinion for the Snake River and Columbia River dams; operations described in the Council's Fish and Wildlife Program; and other fish mitigation measures. If and to the extent the effects of new biological opinions or other measures to protect fish and wildlife are different than those assumed in the 2009 Pacific Northwest Loads and Resources Study, such changes will be reflected in future hydro-regulation studies. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

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

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

(6) Other Reclamation Projects include: Palisades (1957), Anderson Ranch (1950), Chandler (1956), Green Springs (1960), Minidoka (1909), Black Canyon (1925), Boise Diversion (1908), and Roza (1958).

(7) The Dalles Dam complex also includes two units that generate energy in connection with a fishway at the dam. They produce approximately five megawatts of both peak capacity and energy. The output is not purchased by Bonneville and is not included in this table.

(8) Other Corps Projects include: Albeni Falls (1955), Big Cliff (1954), Bonneville Fishway (1981), Cougar (1964), Detroit (1953), Dexter (1955), Foster (1968), Green Peter (1967), Hills Creek (1962), Lookout Point (1954) ,and Lost Creek (1975).

(9) Columbia Generating Station operates under a two-year maintenance and refueling schedule and a refueling outage and extended maintenance outage are scheduled for Operating Year 2011. Bonneville assumes that the Columbia Generating Station will provide about 878 annual average megawatts in most refueling years and 1,030 annual average megawatts in non-refueling years.

(10) Other Non-Federal Hydro Projects include the following hydroelectric projects estimated by water conditions: Lewis County PUD's Cowlitz Falls (1994) and the Idaho Falls Power Bulb Turbine Projects (1982). Bonneville acquired the generation for the output from the Idaho Falls Power Bulb Turbine Projects (1982) through September 30, 2021. If Bonneville's contracts to purchase power from any of these projects are renewed, those projects will be included in future studies.

(11) Other Non-Federal Projects include the following projects: the Georgia Pacific Paper's Wauna Cogeneration Project (1996), the State of Idaho DWR's Clearwater Hydro (1998) and Dworshak Small Hydro (2000) projects, U.S. Park Service's Glines Canyon Hydro (1927) and Elwah Hydro (1910) projects, shares of Foote Creek, LLC's Foote Creek 1 (1999), Foote Creek 2 (1999), and Foote Creek 4 (2000) wind projects, a share of PacifiCorp Power Marketing/Florida Light and Power's Stateline wind project, Condon Wind Project LLC's Condon wind project, NWW Wind Power's Klondike Phase 1 (2001) wind project, a share from NWW Wind Power's Klondike Phase III (2007), and a share of the City of Ashland's solar project.

(12) Bonneville Contract Purchases include contracts for power from both inside and outside the Region, including Canada.

Bonneville's Power Trading Floor Activities

Much of Bonneville's resource base is provided by hydroelectric facilities, the output of which is affected by weather conditions, stream-flows, operating constraints and other factors. In most years, Bonneville also sells substantial amounts of seasonal surplus (secondary) energy in market-based transactions. In addition, other generation conditions and requirements generally may affect generation output. Thus, actual generation availability and output may vary hourly, daily, monthly or seasonally. In addition, power loads fluctuate based on consumer usage, demands to maintain transmission system stability and other factors. Thus, loads and availability of generation from Bonneville's own resources can vary substantially and, on an operational basis during a year, actual power from Bonneville's own generating resources may not match its loads. In the near-term (prior to and during a fiscal year), Bonneville routinely produces probabilistic and discrete studies estimating potential surplus or deficits for specific future time periods. Based on these studies and specific marketing guidelines, Bonneville actively manages short-term surpluses and deficits through real-time, within-month, and forward sales and purchases and physical power options.

Bonneville believes that its revenues and expenses from market transactions are, and will be, subject to several key risks: (i) the level and volatility of market prices for electric power in western North America, which affect the revenues Bonneville receives from discretionary sales of energy and the cost of necessary power purchases Bonneville may have to make to meet contracted loads; (ii) the level of Bonneville's load serving obligation; (iii) water conditions in the Columbia River basin, which determine the amount of hydroelectric power Bonneville has to sell and its economic value and the amount of power it has to purchase in order to meet its commitments; (iv) changes in fish protection requirements, which could be the source of substantial additional expense to Bonneville and could further affect the amount and value of hydroelectric power from the Federal System; (v) continued availability of the capability of existing generating resources; and (vi) operating costs, generally.

Bonneville has put in place risk management procedures, standards and policies that it believes adequately mitigate risk from these activities. Nonetheless, Bonneville's exposure to operational variability means that Bonneville may in certain conditions have to incur substantial purchased power expense.

Customers and Other Power Contract Parties of Bonneville's Power Services

Bonneville's primary transacting counterparties are composed of four principal groups: Preference Customers, DSIs, Regional IOUs, and Market Counterparties. Under the Northwest Power Act, Bonneville has a statutory obligation to meet electric power loads in the Region that are placed on Bonneville by electric power utilities. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region."

Preference Customers

Bonneville's primary customer base is composed of Preference Customers, which make long-term power purchases from Bonneville at cost-based rates to meet their native loads in the Region. Preference Customers are qualifying publicly-owned utilities and consumer-owned electric cooperatives within the Region, and they are entitled by law to a preference and priority ("Public Preference") in the purchase of available Federal System power for their load requirements in the Region. Such customers are eligible to purchase power at Bonneville's lowest cost rate, the PF Rate, for most of their loads, and 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, Public Preference does not compel Bonneville to lower the offered price of uncommitted surplus Bonneville power to Preference Customers before meeting a competing request at a higher price for such uncommitted power from a non-Preference entity. Bonneville sells power to certain large Preference Customers under market type contracts other than for their own load requirements. Bonneville also sells relatively small amounts of power to several Federal agencies in the Region. While such Federal agency customers do not qualify as Preference Customers, they are entitled to buy power from Bonneville at the PF Rate.

Direct Service Industrial Customers

Bonneville may, but is not required to, sell power to a limited number of DSIs within the Region for the purchase of power for their direct consumption. Almost all of Bonneville's service to DSIs has been to aluminum smelting or processing facilities. Most of the aluminum industry in the Pacific Northwest has ceased to operate. Currently, Bonneville sells power to two DSIs in the aggregate amount of 340.1 annual average megawatts. Bonneville ceased serving a third DSI, Columbia Falls Aluminum Company ("CFAC") in August 2009. CFAC's service with Bonneville was about 160 annual average megawatts. It is possible that Bonneville could recommence service to CFAC.

Regional Investor-Owned Utilities

As required by the Northwest Power Act, Bonneville has offered, and four of the six Regional IOUs have agreed to, contracts under which Bonneville could serve Regional IOUs with electric power for their net requirements beginning Fiscal Year 2020 if such service is requested not later than the end of Fiscal Year 2016. 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. Power sales to Regional IOUs are distinct from Bonneville's contracts implementing the Residential Exchange Program, as provided by statute. The Residential Exchange Program obligations, described herein, result in payments by Bonneville to participating utilities. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

Market Counterparties and Exports of Surplus Power to the Pacific Southwest

Bonneville has a large number of parties with whom it has commercial power-related arrangements that are not based on Bonneville's statutory obligations (as in the case of statutory load-meeting obligations to Preference Customers and Regional IOUs, and payment obligations under the Residential Exchange Program) or on long-term relationships that are based on prior statutory obligations (as in the case of DSIs). These counterparties include utilities located outside the Region, power marketers and independent power producers. Transactions with these counterparties include, but are not limited to, arrangements for the purchase, sale and/or exchange of power, transmission and related services.

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 seasonal surplus (secondary) energy that are surplus to Bonneville's Regional requirements. Exports of Bonneville power for use outside the Pacific Northwest are subject to a statutory requirement that Bonneville offer such power for sale to Regional utilities to meet Regional loads before offering such power to a customer outside the Region. However, in the opinion of Bonneville's General Counsel, Bonneville is not required to reduce the rate of proposed export sales to meet a Regional customer's request if the proposed export sale is at a higher FERC-approved rate than the Regional customer is willing to pay.

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

Pacific Southwest utilities typically account for the greatest share of purchases of seasonal surplus (secondary) energy from Bonneville and these transactions account for the greatest share of revenues from Bonneville's exports. The amount of seasonal surplus (secondary) 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.

Credit Risk

Credit risk may be concentrated to the extent that one or more groups of counterparties, including purchasers and sellers, in power transactions with Bonneville have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. 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 that relate to other market participants that 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.

Effect on Bonneville of Developments in California Power Markets in 1999-2001

In connection with the historically high power prices and volatility in West Coast power markets in 1999-2001, FERC initiated three proceedings (collectively, "the West Coast FERC Proceedings") to address, under the Federal Power Act ("FPA"), whether certain power sellers charged unjust and unreasonable prices and therefore should refund to power purchasers any amounts overcharged. The FERC proceedings and the problems experienced in West Coast power markets in 1999-2001 have also engendered litigation affecting Bonneville.

In the "California Refund Docket," FERC is examining whether to order refunds from entities that sold power into California power markets in 2000 and 2001. More particularly, FERC is examining whether and the extent to which power prices charged to two entities created under California state law to facilitate competitive power markets in the state were "unjust and unreasonable." These entities are the California Power Exchange ("Cal-PX") (which filed for bankruptcy protection and has ceased operations) and the California Independent System Operator ("Cal-ISO"), both of which had obligations to purchase power under the competitive power market structure that California established. Bonneville sold power to the Cal-ISO and the Cal-PX in 2000 and 2001. They have separate outstanding payment obligations to Bonneville for such sales, which Bonneville estimates to be about $75 million in aggregate, plus interest. (Bonneville has recorded provisions for uncollectible amounts, which in management's best estimate are sufficient to cover any potential exposure.

In litigation arising out of the California Refund Docket, the Ninth Circuit Court ultimately held, in September 2005, that Bonneville was not (under law in effect at the time) subject to FERC authority to order refunds. As a result of the court's ruling, the California Refund Docket cannot result in any refund liability to Bonneville.

In light of the court ruling, three California-based investor-owned utilities (Pacific Gas and Electric ("PG&E"), San Diego Gas and Electric and Southern California Edison ("SCE")), the California Electricity Oversight Board, a California state agency, and the California Attorney General on behalf of the California Energy Scheduling Resources, a California state agency, filed separate breach of contract claims against Bonneville in the United States Court of Federal Claims in March 2007. Each claim seeks unspecified damages related to Bonneville's power sales into the Cal-PX and Cal-ISO markets. The California parties allege that Bonneville is contractually obligated to provide refunds of amounts received in excess of the mitigated market clearing prices for certain periods in 2000 and 2001, as established by FERC in separate refund proceedings and notwithstanding that FERC has no authority to order refunds against Bonneville for the related sales. The California parties also seek to recover pre-judgment and post-judgment interest and litigation costs.

Bonneville estimates that the aggregate contract damages claimed by California parties in the Court of Federal Claims contract litigation arising out of the California Refund Docket are $170 million in specified damages plus an additional amount of unspecified damages. In October 2008, Bonneville filed answers to the various complaints. There is currently pending a motion to stay the proceedings pending the outcome of some unresolved matters at FERC and the Ninth Circuit Court in related proceedings. These unresolved matters could affect the claims filed in these proceedings.

In the second West Coast FERC Proceeding (the "Northwest Spot Market Docket"), FERC reviewed the extent to which power prices in the bilateral "spot market" in the Pacific Northwest were "unjust and unreasonable" in certain periods in 2000 and 2001. In November 2003, FERC concluded, among other things, that the prices during the relevant period were not unjust and unreasonable, that refunds should not be ordered, and that FERC would terminate the proceeding. Appeals challenging the order were filed in the Ninth Circuit Court. The Ninth Circuit Court has issued an opinion remanding the matter to FERC to further consider the denial of refunds. Based on the Ninth Circuit Court's decision that FERC lacked jurisdiction to order Bonneville to provide refunds under then-applicable law, Bonneville believes that the Northwest Spot Market Docket will not result in any refund liability to Bonneville.

In the third West Coast FERC Proceeding (the "Show Cause Proceeding"), FERC issued "Show Cause Orders" to Bonneville and other West Coast power market participants in an investigation of whether they had manipulated prices in West Coast power markets in and after 2000. After further review, FERC dismissed the Show Cause Order with respect to Bonneville. Certain parties appealed the dismissal to Federal appellate court and FERC moved to dismiss the appeal. The Federal appellate court has not yet rendered a decision on the motion to dismiss the appeal.

In Fiscal Year 2005, Congress enacted the Energy Policy Act of 2005 ("EPA-2005"), which subjects Bonneville to FERC jurisdiction on a prospective basis for purposes of establishing refund liability. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005." For a description of litigation between Southern California Edison and Bonneville arising out of developments in West Coast energy markets in 1999-2000, see "BONNEVILLE LITIGATION—Southern California Edison v. Bonneville Power Administration."

Certain Statutes and Other Matters Affecting Bonneville's Power Services

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

The Northwest Power Act requires Bonneville to meet certain firm loads in the Region placed on Bonneville by contract by various Preference Customers and Regional IOUs. Bonneville believes it does not have a statutory obligation to meet all firm loads within the Region. Bonneville is not obligated by law to sell power to a DSI.

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

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

Some of Bonneville's Preference Customers and all of the Regional IOUs have generating resources, which they may use to meet their firm loads in the Region. Each of such customers has to identify the amount of its loads it would meet with its own resources, thereby providing Bonneville with advance notice of the need to add resources or take other steps to meet these loads. These provisions are also included in all existing power sales contracts under which Bonneville has a load following obligation, including under the New Long-Term Preference Contracts. The New Long-Term Preference Contracts include provisions that enable Preference Customers to put additional net requirements load on Bonneville, although Bonneville will serve such new loads at Tier 2 PF Rates, which Bonneville expects will be higher than Tier 1 PF Rates. Bonneville has executed requirements agreements with four Regional IOUs for the period after Fiscal Year 2011, but no requirements power will be provided under these agreements until at least Fiscal Year 2020. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Sales and Related Arrangements in the Period after Fiscal Year 2011—Residential Exchange Program and Other Arrangements with Regional IOUs after Fiscal Year 2011."

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

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

Bonneville's loads and resources are subject to a number of uncertainties over the coming years. Among these uncertainties are: (i) the level of loads and types of loads placed on Bonneville under the provisions of the Northwest Power Act; (ii) the amount of power purchases, resource acquisitions and other arrangements that Bonneville will have to make to meet contracted loads; (iii) future non-power operating requirements from future biological opinions or amendments to biological opinions; (iv) the availability of 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; (vi) the overall load growth from population changes and economic activity within the Region; and (vii) evolving transmission system needs to provide ancillary services.

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

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

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

Bonneville's resource acquisitions under the Northwest Power Act are guided by a Regional conservation and electric power plan (the "Power Plan") prepared by the Northwest Power and Conservation Council (the "Council"). The governors of the states of Washington, Oregon, Montana and Idaho each appoint two members to the Council, which is charged under the Northwest Power Act with developing and periodically amending a long range power plan to help guide energy and conservation development in the Region. The Power Plan sets forth guidance for Bonneville regarding implementing conservation measures and developing generating resources to meet Bonneville's Regional load obligations. The Power Plan is revised by the Council approximately every five years. On February 10, 2010, the Council released its Sixth Northwest Power Plan (the "Power Plan"). 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 Services—Fish and Wildlife."

The Power Plan addresses risks and uncertainties for the Region's electricity future and seeks a resource strategy that minimizes the expected cost of the Regional power system over the next 20 years.

According to the Power Plan, cost-effective energy efficiency could meet 85 percent of the new load over the next 20 years (about 5,900 of 7,000 average megawatts). This efficiency, combined with new renewable energy, could delay investments in new fossil-fuel power plants until future environmental legislation is clear and alternative low-carbon energy sources have matured in technology and cost. The resource strategy in the Power Plan includes five specific recommendations: (i) Develop cost-effective energy efficiency aggressively — at least 1,200 average megawatts by 2015, and equal or slightly higher amounts every five years through 2030. (ii) Develop cost-effective renewable energy as required by state laws, particularly wind power, accounting for its variable output. (iii) Improve power-system operating procedures to integrate wind power and improve the efficiency and flexibility of the power system. (iv) Build new natural gas-fired power plants to meet local needs for on-demand energy and back-up power, and reduce reliance on existing coal-fired plants to help meet the power system's share of carbon-reduction goals and policies. (v) Investigate new technologies such as the "smart-grid," new energy-efficiency and renewable energy sources, advanced nuclear power, and carbon sequestration.

Bonneville strongly supports the Power Plan's reliance on energy efficiency and renewable energy (primarily wind power) to meet the Region's future load growth and is committed to meeting Bonneville's 42 percent share of the Council's Regional conservation target. Bonneville's share equates to about 500 annual average megawatts of savings in aggregate over the five-year period of the Power Plan. Bonneville is working to develop new programs and expects to ramp up efforts in order to achieve this level of conservation in the aggregate over the five-year period. Achieving the conservation targets will help Bonneville manage future load-growth and minimize reliance on development of new generating resources in order to meet demand.

Bonneville's Resource Program and Bonneville's Resource Strategies for the Post-2011 Period. In September 2009, Bonneville issued a "Draft Resource Program" to evaluate whether Bonneville may need to acquire resources to meet its power supply obligations, primarily to customers under the New Long-Term Preference Contracts. Bonneville expects to issue the final Resource Program in September 2010.

The Draft Resource Program also supplies information to Bonneville's customers about resources available to meet their needs. The planning horizon for the Draft Resource Program extends through Operating Year 2019. In addition to examining annual energy needs, the Draft Resource Program assesses Bonneville's needs for monthly/seasonal heavy load hour energy, capacity needs for extreme weather events and hourly balancing reserves through Operating Year 2019. These multiple analyses have provided a much clearer and more specific picture of Bonneville's needs.

The needs assessment showed that recent events, including the current economic recession, have diminished Bonneville's near-term resource needs. As a result, Bonneville expects to satisfy much of its expected supply needs through Operating Year 2013 with conservation and short-term power purchases from the wholesale power market. In Operating Year 2019, deficits are substantially greater but continued conservation efforts may not be sufficient in all load scenarios. Bonneville intends to meet the public power share of the Council's conservation targets in its final Sixth Power Plan.

Bonneville's Draft Resource Program states that the additional power supply Bonneville will need to secure, if any, after achieving conservation targets will depend in large part on the outcome of a number of uncertainties about loads that Bonneville may or may not serve: (i) Preference Customer choices of power supplier(s) for their Tier 2 loads under the new Long-Term Preference Contracts; (ii) long-term service to the DSIs; (iii) potential formation of new public or tribal utilities that can place load on Bonneville; (iv) increased load service to a DOE site in Richland, Washington; and (v) the growth of the wind power fleet in the Bonneville balancing authority area and the magnitude and source of supply for reserves to support wind power integration to the Federal Transmission System. (Subsequent to the issuance of the Draft Resource Program, Preference Customers committed to placing a comparatively small amount of Tier 2 Loads on Bonneville: 21 annual average megawatts in Fiscal Year 2012 increasing to 56.4 annual average megawatts in Fiscal Year 2014.)

The Draft Resource Program identifies additional uncertainties that also could affect Bonneville's need for resources, including the amount and timing of long-term Regional economic growth, the rate and timing of forecast long-term load growth, fish requirements that impact hydro-generation, success of conservation efforts, continued availability of existing resources and others.

Short-Term Power Purchases. Bonneville's approach for the post-2011 period, as set forth in the New Long-Term Preference Contracts, is to provide Regional Customers with the opportunity to meet their own incremental loads without facing increased costs for service to their existing loads as a result of such decision. Nonetheless, to the extent that Bonneville assumes incremental load obligations above the existing generating resources of the Federal System, Bonneville must obtain additional electric power. Bonneville believes that, in general, new sources of power should have fixed costs that can be recovered over a shorter period, should provide power in the times of the year when power is required, should be capable of being displaced when hydroelectric power is available and should have costs that can be offset when hydroelectric power is available. Short-term purchases are the one type of resource that meets incremental load obligations without incurring long-term fixed costs.

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

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

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

Renewable Energy. Bonneville presently purchases a total of approximately 66 annual average megawatts from various wind energy projects in Wyoming, Oregon and Washington and small amounts of power from solar photovoltaic projects. Bonneville also has contracted to purchase 49.9 megawatts from a geothermal project. This project has not been built. It was originally scheduled to become operational in December 2005 but it is not clear yet whether the site is a viable geothermal resource and the project site is the subject of on-going environmental litigation. Bonneville's expectation of the earliest date for commercial operation has been extended to October 1, 2015.

Acquisition of renewable resource output from specific projects is a potential source of energy to meet forecasted deficits. In addition to any renewable resource acquisitions, Bonneville has launched several initiatives: (1) Bonneville has formed a technical cross agency team dedicated to designing cost-effective means to integrate large amounts of wind into the Federal System; (2) Bonneville issued a renewable resource information request designed to provide Bonneville and its customers with information on renewable generation available for purchase over the next several years; and (3) Bonneville will continue during Fiscal Years 2010 and 2011 to provide direct programmatic funding for research and development activities including long-term solar and wind data monitoring.

Electric Power Conservation. Bonneville also has programs intended to encourage the development of electric power conservation measures in the Region. Electric power conservation can reduce the demand for Bonneville to meet electric power loads. During the 2010-2011 Rate Period, Bonneville is providing a $.50 per megawatt-hour rate discount to those of its customers that implement conservation measures. In addition, Bonneville has a target of facilitating the development of 80 annual average megawatts of new conservation during Fiscal Year 2010. Bonneville estimates that under its Fiscal Year 2010 conservation program, it will cost about $1.5 million per annual average megawatt of energy savings.

Bonneville estimates that it achieved new conservation savings of 76 annual average megawatts in Fiscal Year 2008 and 71 average megawatts in Fiscal Year 2009. Future conservation acquisition programs are expected to lessen Bonneville's reliance on spot market or other electric power purchases in the post-2011 period.

Wind Generation Development and Integration into the Federal Transmission System. As the owner/operator of the Federal Transmission System, the largest bulk transmission system in the Region, Bonneville is responsible for transmitting electric power from and integrating most of the new wind generation projects that are located in the Region or that are transmitted into or through the Region. Bonneville estimates that over 2,700 megawatts of wind generation facilities are now interconnected to the Federal Transmission System. Bonneville expects that an additional 815 megawatts of wind power will be integrated by the end of calendar year 2010. Future wind generation integration is expected to increase substantially with future wind project development in the Region. With the recent enactment by western states of renewable energy portfolio requirements applicable to electric power utilities, Bonneville expects that substantial additional wind generation investments will continue to be made for the foreseeable future.

The preceding megawatt estimates of wind generation reflect potential generation of the facilities themselves and do not reflect estimated energy output, which depends on the availability and intensity of wind. Bonneville estimates that actual average generation over a year for all wind generation in the Region is roughly 30 percent of the installed capacity of the wind generation facilities.

From an electric power system perspective, Bonneville believes that wind energy provides no electric power capacity because its availability depends on the wind, and therefore is not reliable to be called on when needed. In addition, even when wind resources are generating, actual output can vary substantially in relatively short time frames. This means that other generating resources must be available and be relied on to provide necessary reserves to meet sudden declines in wind generation. Generation resources must also be available to be scaled back to accommodate unexpected upsurges in wind generation. Thus, integration of wind energy into the Federal Transmission System provides some operational challenges to assure system wide reliability and the efficient effective transmission of wind from generation source to loads.

One of the complexities relates to the operation of the hydro-power generating resources of the Federal System. While the Federal System hydro-power is highly flexible since it can be called on to increase or decrease electric generation on short notice to manage wind fluctuations, system operation limitations restrict that flexibility. For example, in the spring and summer, the system is operated to spill water to aid downstream migrant fish. Bonneville has developed processes to assure that wind generation integration does not adversely affect meeting Endangered Species Act ("ESA") fish requirements by establishing the ability to cut wind generation schedules. Finally, integrating new resources (wind or otherwise) may also require facilities investments, such as new transmission lines and substations or improvements to existing facilities, in order to transmit the additional electric power.

All costs of Bonneville's wind integration efforts are recovered in its rates. See "TRANSMISSION SERVICES—Bonneville's Transmission and Ancillary Services Rates."

In calendar year 2009, Bonneville formed a technical cross agency team dedicated to designing cost-effective means to integrate large amounts of wind into the Federal System. One of the team's first tasks was the examination of the potential for third-party generation to meet within-hour capacity needs (to increase and decrease third party generation in response to variations in wind generation). Bonneville issued a subsequent Request for Information for electric power capacity sources. Ultimately, Bonneville determined that methods apart from acquiring generating resources would, in the near-term, be sufficient to meet wind integration needs. Bonneville is now developing a proposal that would enable wind generators to self-supply their own within-hour capacity from other generating resources as necessary to integrate their resources into the Federal Transmission System. It is still unclear whether this self supply proposal will meet the growing need for within-hour capacity reserves. For the long-term, it is possible that Bonneville may seek to obtain new generating resources to meet its responsibilities as a transmission operator.

Apart from wind integration issues, it is possible that continued wind power development may affect the prices that Bonneville receives for seasonal surplus (secondary) power. Much of Bonneville's seasonal surplus power is derived in the spring when river flows are the greatest. Coincidentally, the spring months also tend to be windy, and wind generation in the spring is at is peak. In periods of high hydroelectric output, Bonneville can agree with owners of thermal (coal, oil and gas) generation to "economically displace" their thermal generation with hydro-power, thereby saving thermal fuel costs. Displacement of wind generation by Bonneville is different given that wind generators do not have fuel costs, so they see no cost-savings to achieve by displacing their generation. Some wind generators also receive Federal income tax incentives in the form of production tax credits under which the credit is based on the amount of electric power actually generated. This also makes economic displacement arrangements more difficult to develop.

Residential Exchange Program

Implementing the Residential Exchange Program. The Northwest Power Act created the Residential Exchange Program to extend the benefits of low-cost Federal power to certain residential and small farm power users in the Region. In effect, the program results in cash payments by Bonneville to exchanging utilities, which are required to pass the benefit of the cash payments through in its 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 changes hands. Rather, Bonneville makes cash payments to each exchanging utility in an amount determined by multiplying the utility's eligible residential load times the difference between the utility's average system cost and Bonneville's applicable Residential Exchange Rate (which is an adjusted version of the PF Rate), if such rate is lower. The 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—Federal System Statement of Revenues and Expenses."

Changes in the Provision of Residential Exchange Program Benefits. In Fiscal Year 2001, Bonneville and each of the six Regional IOUs, all of which had theretofore participated in the Residential Exchange Program, entered into separate ten-year contracts ("Residential Exchange Settlement Agreements") in an attempt to settle Bonneville's statutory Residential Exchange Program obligations with respect to such utilities during the period July 1, 2001 through September 30, 2011. Subsequent to the execution of the original Residential Exchange Settlement Agreements, Bonneville and the Regional IOUs entered into a number of amendments and supplemental arrangements relating to Bonneville's five-year power rate period beginning October 1, 2001. These amendments and the exercise by some Regional IOUs of contractual provisions were intended to increase the amount of cash payments that Bonneville would make with respect to the Residential Exchange Settlement Agreements and reduce certain physical power sales thereunder. As a result of the Residential Exchange Settlement Agreements and subsequent related actions, the annual aggregate cash payments to Regional IOUs that Bonneville paid under the foregoing arrangements were between $304 million and $367 million in the four fiscal years beginning with Fiscal Year 2002. In Fiscal Year 2007, Bonneville paid about $168 million to the Regional IOUs until it suspended payments in light of the Ninth Circuit Court's May 2007 ruling that the Residential Exchange Settlement Agreements were invalid. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

The court found that Bonneville's reliance on the settlement of its statutory obligations under the Residential Exchange Program Settlement Agreements was not consistent with the Residential Exchange Program provisions of the Northwest Power Act. The court also directed Bonneville to set power rates consistent with the rulings. Because the ruling was issued after Bonneville had prepared its final power rate proposal for Fiscal Years 2007-2009, Bonneville prepared a "2009 Supplemental Power Rate Proposal," under which Bonneville took the ruling into consideration.

Under the 2009 Supplemental Power Rate Proposal, Bonneville determined four principal items: (i) the Residential Exchange Program benefits levels that should have been set for Fiscal Years 2002 through 2008, (ii) the level of Residential Exchange Program benefits to be paid in Fiscal Year 2009, (iii) the Preference Customer power rates (PF Rates) that should have been set for Fiscal Years 2002 through 2008 (assuming the re-determined Residential Exchange Program benefits in such years), and (iv) new power rate (PF Rate) levels for Preference Customers in Fiscal Year 2009.

To replace the invalidated Residential Exchange Program Settlement Agreements, Bonneville also developed and entered into short-term Residential Exchange Program agreements, which effectuate the Residential Exchange Program provisions of the Northwest Power Act for Fiscal Years 2009 through 2011. Bonneville has also entered into the Long-Term Residential Purchase and Sales Agreements ("Long-Term RPSAs") with three of the Regional IOUs for Fiscal Years 2012 through 2028 and has proposed to enter into similar agreements with the other three Regional IOUs. Bonneville has also prepared and submitted to FERC for review a new average system cost methodology to apply in the determination of Residential Exchange Program benefit levels in the 2009-2010 Rate Period and beyond. FERC has granted final approval to the new average system cost methodology.

Bonneville also determined the means by which it will correct the past overpayment of Residential Exchange Program benefits and the corresponding effects on Preference Customer rates (the overpayments of Residential Exchange Program benefits in the period during which Bonneville operated under the Residential Exchange Settlement Agreements resulted in higher rate levels to Preference Customers than otherwise would have been the case). The re-calculation of Residential Exchange Program benefits for the period during which Bonneville operated under the Residential Exchange Settlement Agreements ("Look-back Period") resulted in reduced Residential Exchange Program benefit levels for the same period, and, as a consequence, in lower effective PF Rates for Preference Customers. Bonneville decided that past overpayments of Residential Exchange Program benefits during the Look-back Period would be gradually recovered through offsetting reductions to Bonneville's future payments to Regional IOUs for Residential Exchange Program benefits. These payment offsets in Bonneville's Residential Exchange Program benefits payments to Regional IOUs are referred to as "Look-back Amounts". Bonneville also determined to pass the benefits of such Look-back Amounts directly on to Preference Customers in the form of corresponding payments and downward adjustments in their power bills. Bonneville estimates that as of the end of Fiscal Year 2009, the un-recouped aggregate overpayment of Residential Exchange Program benefits was about $625 million.

Fish and Wildlife

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

Bonneville typically funds fish and wildlife mitigation through several mechanisms. Since the creation of the Federal System, Bonneville has repaid the United States Treasury the share of the costs of mitigation by the Corps and Reclamation that is allocated by law or pursuant to policies promulgated by FERC's predecessor to the Federal System projects' power purpose (as opposed to other project purposes such as irrigation, navigation and flood control). These measures mitigate the impact on fish and wildlife of the construction and operation of hydroelectric dams of the Federal System.

Bonneville also implements and funds measures recommended by the Council to implement the Council Program, which the Council periodically amends. The Council Program calls for a variety of mitigation measures from habitat protection to main-stem Columbia River and Snake River flow targets. When such measures affect the operation of the Federal System and require Bonneville to purchase power to fulfill contractual demands or to spill water and thereby forgo generation of electricity, for instance, those financial losses are counted as measures funded by Bonneville. While many of the measures in the Council 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 projects in support of the Council Program, and which include expense and capital components for ESA–related and some non-ESA-related measures that are located at sites away from the Federal System dams; (ii) "Expenses for Recovery of Capital," which include depreciation, amortization and interest expenses for fish and wildlife capital investments by the Corps, Reclamation and Bonneville; and (iii) "Other Entities' O&M," which include fish and wildlife O&M costs of the Fish and Wildlife Service for certain fish hatcheries and of the Corps and Reclamation for Federal System projects.

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

Bonneville estimates that in Fiscal Year 2009, Direct Costs and Replacement Power Purchase Costs in aggregate were about $602 million and Foregone Power Revenues were about $143 million.

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

Among other things, the ESA requires that Federal agencies such as Bonneville, the Corps and Reclamation, take no action that would jeopardize the continued existence of listed species or result in the destruction or adverse modification of their critical habitat. Since 1991, there have been listed as threatened or endangered under the ESA thirteen species of anadromous fish (salmon and steelhead), and two species of resident fish (bull trout and sturgeon) 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 Federal System hydroelectric dam operations with respect to the anadromous listed species, and the United States Fish and Wildlife Service has developed biological opinions with respect to the resident listed species. These biological opinions provide information that Bonneville, the Corps and Reclamation can use to ensure that their actions with respect to the operation of the Federal System satisfy the ESA. By acting consistently with the biological opinions, Bonneville, the Corps and Reclamation demonstrate that jeopardy to listed species is being avoided. The implementation of the ESA with respect to the Federal System has been and is the subject of litigation and judicial review.

Operation of the Federal System hydroelectric dams consistent with the ESA 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. Second, less water may be stored in the upstream reservoirs for fall and winter electric generation because more water is committed to use in the spring and summer to increase flows to aid downstream fish migration. Consequently, there is relatively less water available for hydroelectric generation in the fall and winter and more water available in the spring and summer. Because of these changes, under certain water conditions, Bonneville has had to, and may have to, purchase additional energy for the fall and winter to meet load commitments that would otherwise have been met with the hydroelectric system. In addition, the flow changes have meant that Bonneville has had comparatively more surplus energy to market in the spring and summer. Bonneville estimates that the impact of operating the Federal System in conformance with the biological opinions and the Council Program, as in effect as of the beginning of Fiscal Year 2000, decreased Federal System generation capability by about 1,000 annual average megawatts, assuming average water conditions, from levels immediately preceding the issuance of the NOAA Fisheries biological opinion in 1995. The consequences of this and similar ESA-related decrements in generation are reflected in the Replacement Power Purchase Costs and Foregone Power Revenues described above.

These ESA listings and related actions to protect listed species and their habitat have resulted in substantial cost increases to Bonneville. Prior to the initial ESA listings, Bonneville's fish and wildlife mitigation 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 Fiscal Year 1995. Bonneville estimates that the total of Direct Costs and Operational Impacts was about $716 million in Fiscal Year 2007, about $876 million in Fiscal Year 2008, and about $745 million in Fiscal Year 2009. Direct Costs in Fiscal Year 2009 were higher than in Fiscal Year 2008 ($327 million in Fiscal Year 2008 compared to $362 million in Fiscal Year 2009) due to additional ESA projects required by NOAA Fisheries. Operational Costs decreased by about $166 million, from $549 million in Fiscal Year 2008 to $383 million in Fiscal Year 2009. The economic downturn drove down the demand and market price for electricity in Fiscal Year 2009 when compared to Fiscal Year 2008 and meant that less hydro-generation was foregone due to fish operations and as a result there was a decrease of Foregone Power Revenues from about $274 million in Fiscal Year 2008 to $143 million in Fiscal Year 2009. Due to decreased demand for electricity, Bonneville incurred lower Replacement Power Purchase costs, decreasing from $275 million in Fiscal Year 2008 to $240 million in Fiscal Year 2009. Actions under the ESA affect other costs that Bonneville bears, including mitigation activities such as hatchery programs, which costs are included in the Council Program, discussed below. In the future, Bonneville will also provide funding under the funding agreements entered into with certain tribes and the states of Idaho, Montana, and Washington. See "—Columbia River System Biological Opinions."

Columbia River System 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's Columbia River hydroelectric dams. The 2000 Biological Opinion was coordinated with a Fish and Wildlife Service biological opinion issued in 2000 relating to certain other species. The 2000 Biological Opinion included a number of measures affecting Federal System dam operations and dam configurations in order to improve anadromous fish passage survival through the hydro system.

Included among the 13 biological opinion alternatives around which Bonneville developed its final power rates for the five years ended September 30, 2006 were several alternatives that would have called for breaching four Federal System Snake River dams. The direct cost of breaching the dams would be very high. In addition, the loss of the generation from the dams would substantially affect the power generation capability of the Federal System, reducing current expected output by approximately 1,200 annual average megawatts under average water assumptions, resulting in significantly increased power purchases and/or lost power sales.

A number of interests filed litigation in connection with the 2000 Biological Opinion. In May 2003, the United States District Court for the District of Oregon ("District Court") ruled that the 2000 Biological Opinion was inadequate. In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court. On November 30, 2004, NOAA Fisheries finalized a "2004 Biological Opinion" to replace the 2000 Biological Opinion and address the deficiencies therein identified by the reviewing court.

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

A number of interests filed litigation challenging the 2004 Biological Opinion. In October 2005, the District Court invalidated the 2004 Biological Opinion on a number of grounds but left it in place during the court-ordered remand of the 2004 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court. See "BONNEVILLE LITIGATION—ESA Litigation—Columbia River." NOAA Fisheries issued a final biological opinion (the "2008 Columbia River System Biological Opinion") on May 5, 2008 (discussed below).

In calendar year 2008, Bonneville, the Corps and Reclamation, and a number of Regional interests including five tribes, an inter-tribal association and the states of Montana and Idaho, signed a number of separate agreements to assure long-term fish and wildlife funding with respect to the Federal System. The agreements, collectively known as the Columbia Basin Fish Accords, are designed to improve habitat and strengthen fish stocks in the Columbia River Basin over the next ten years. Most of the funding will be provided by Bonneville. Under the agreements, the tribes and states commit to accomplishing biological objectives with the funds, linked to meeting the federal agencies' statutory requirements.

These agreements were followed by an agreement between the federal agencies and the State of Washington addressing the Columbia River estuary on September 16, 2009.

The agreement among the State of Idaho, Bonneville, and the Corps and Reclamation, the agreement among the State of Montana, Bonneville, the Corps and Reclamation, and the agreement among the State of Washington, Bonneville, and the Corps and Reclamation are similar to the agreements with the tribes in that they are designed to improve habitat and strengthen fish stocks. With regard to the Idaho agreement, the measures are focused primarily in the Snake River Basin. With regard to the Montana agreement, the measures are focused primarily on listed resident fish (non ocean-going) in Montana. With regard to the Washington agreement, the measures are focused on improving habitat in the Columbia River estuary area for all listed stocks.

Under the foregoing agreements with the tribal interests, and Montana, Idaho, and Washington, Bonneville has committed to make available roughly $996 million over the ten-year period ending September 30, 2018.

Bonneville estimates that roughly 60 percent of its proposed funding commitments in the agreements would be for new work required for implementation of the final 2008 Columbia River System Biological Opinion and otherwise agreed to in furtherance of Federal statutory fish and wildlife purposes such as the Northwest Power Act. The remaining amounts committed to in these agreements affirm the continuation of activities for fish and wildlife in furtherance of the ESA and Northwest Power Act that would otherwise face funding uncertainty after Fiscal Year 2009. While the foregoing agreements provide funding assurances to implement many actions under the 2008 Columbia River System Biological Opinion to protect listed species under the ESA, the proposed agreements also assure funding for other fish restoration efforts including efforts under the Northwest Power Act.

Additionally, all of the agreements promote a collaborative relationship between the non-Federal parties and the Federal agencies. Under the 2008 agreements, the participating tribes and states agree that the Federal government's requirements under the ESA, the Federal Water Pollution Control Act and the Northwest Power Act are satisfied as to the identified Federal System hydropower projects in the Snake River and Columbia River drainages for the next ten years. The 2009 agreement with Washington provides for similar commitments regarding the ESA. The parties to the agreements also agreed that they will work together to support the agreements in all appropriate venues. The agreements would also specifically resolve, for these parties, ESA litigation regarding Federal System hydropower projects in the Snake River and Columbia River drainages now pending before the District Court. Bonneville also believes that the agreements have helped fulfill the court's requirement that the parties increase collaboration in preparing the 2008 Columbia River System Biological Opinion. The agreements also provide a higher level of assured long-term funding, which was a concern raised by the court in reviewing past biological opinions.

On May 5, 2008, NOAA Fisheries issued the final 2008 Columbia River System Biological Opinion. In comparison to the 2004 Biological Opinion, the 2008 Columbia River System Biological Opinion calls for significant improvements in downstream juvenile passage survival performance standards, spill and operations that are better timed to the needs of individual listed fish species, expanded habitat program, expanded predation-management program, and specific commitments and timetable for site-specific fish hatchery consultations and reforms. Included in the new biological opinion are proposed structural modifications to the hydro-system which are expected to cost about $500 million inclusive of associated research to support those modifications.

These modifications are expected to be funded by specific Federal appropriations, primarily to the Corps. Bonneville expects that it will be responsible for including in its power rates as a repayment to the United States Treasury about 80 percent of the costs of the modifications, which is the estimated portion of such costs assigned by law or administrative practice to be recovered in Bonneville's power rates. Bonneville does not expect that the modifications will be financed with Bonneville's statutory borrowing authority with the United States Treasury. As with other appropriated investments in the Federal System, Bonneville depreciates the portion of the costs to be recovered in power rates from the dates the related capital facilities are placed in service through their expected useful lives. These modifications will be implemented over many years; thus, their costs will gradually be added to Bonneville's rates and appropriated repayment responsibility as they are placed in service.

The 2008 Columbia River System Biological Opinion does not call for dam-breaching, nor does it call for drawing down of reservoirs or other operational changes which could interfere substantially with hydro-electric generation to meet instant demands. Nonetheless, the 2008 Columbia River System Biological Opinion will affect dam operations and will increase both capital costs and operating expenses to Bonneville when compared to the prior biological opinion.

A number of interests, including the State of Oregon, certain tribes, and certain environmental organizations, have challenged the 2008 Columbia River System Biological Opinion in the District Court. See "BONNEVILLE LITIGATION—ESA Litigation—Columbia River."

In April 2009, following an in chambers meeting among all parties to the litigation with the presiding District Court judge in the 2008 Columbia River System Biological Opinion litigation, the administration of President Barack Obama initiated a review of the 2008 Columbia River System Biological Opinion. See “BONNEVILLE LITIGATION—ESA Litigation—Columbia River.”

The review was undertaken by NOAA Fisheries. In September 2009, NOAA Fisheries presented the supplemental review, known as the “Adaptive Management Implementation Plan” (the “Management Plan”), to the court. The Management Plan concludes that the 2008 Columbia River System Biological Opinion, as implemented under the Management Plan, “is legally and biologically sound.” The Management Plan does not amend the 2008 Columbia River System Biological Opinion; rather, it provides a series of short-term and longer-term contingent actions that would be implemented in the event of the occurrence of certain triggering events evidencing biological decline of the ESA-listed species. The short-term actions relate primarily to fish hatchery operations, fish predator management and fish harvest restrictions that can be implemented in less than a year. Longer-term actions include, among other items, alterations to fish predation management approaches, harvest practices, and hatcheries and hatchery practices, all of which would take more than one year to implement.

One long-term contingency action in the event there is a significant decline in the status of a Snake River species is a study of breaching one or more of the four lower Snake River dams of the Federal System. Under the Management Plan, this is considered a “contingency of last resort.” It would be recommended to Congress (as noted herein, dam breaching of any of the Federal System dams would require Congressional enactment authorizing such action) only when the best scientific information available indicates dam breaching would be effective and is necessary to avoid jeopardizing the continued existence of the affected Snake River species taking into account the short-term and long-term impacts of such action.

The Management Plan states that “it is reasonable to study breaching of lower Snake River dam(s) as a contingency of last resort because the status of the Snake River species is improving and the [2008 Columbia River System Biological Opinion] analysis concluded that breaching is not necessary to avoid jeopardy. In addition, breaching lower Snake River dams would have significant effects on local communities, the broader region and the environment. It would require a major investment of resources and time. Therefore, any decision to seek the requisite congressional authority must be driven by the best available scientific information.” The court has taken the Management Plan under advisement. See “BONNEVILLE LITIGATION—ESA Litigation—Columbia River.”

On February 19, 2010, the presiding District Court judge entered a voluntary remand order that gives the Federal agencies three months (until May 20, 2010) to consider, among other actions, integrating the Management Plan into the 2008 Columbia River System Biological Opinion. In order to integrate the Management Plan, it must first be updated to reflect the “best available scientific information.” Prior to the February 19, 2010 order, in a February 10, 2010 letter, the District Court stated that the administrative record "must also include new and pertinent scientific information relating to the proposed action (e.g., recent climate change data)" and that if "that scientific data requires additional analysis or mitigation to avoid jeopardy, the Federal agencies must adequately address those issues." The Federal agencies have begun the remand process.

It is difficult to predict the aggregate increased cost to Bonneville that will arise from the 2008 Columbia River System Biological Opinion. Many measures in the new biological opinion have been implemented, are currently being implemented, or would otherwise be implemented, including under the tribal and state agreements discussed immediately above. Certain measures involve long-term costs or expenses that are difficult to predict. Qualified by the foregoing and other uncertainties, Bonneville estimates that the 2008 Columbia River System Biological Opinion together with the tribal and state funding agreements will in aggregate increase the expense portion of Bonneville’s cost of service by approximately $100 million per year over the ten-year term of the agreements, and increase power rates (all other things being equal) by about four percent, in each case when compared to Fiscal Year 2008 rate levels. This amount does not include Bonneville’s capitalized repayment responsibility for the appropriated costs of the structural modifications described above. As noted above, the capital costs will be included for recovery in Bonneville’s rates as a Federal System appropriation repayment responsibility to the United States Treasury as and when the related facilities are placed in service and then will be depreciated over their expected useful lives.

Bonneville is unable to provide any certainty regarding the costs it may incur, including from possible changes in dam operations, under the ESA or other environmental laws, and whether the 2008 Columbia River System Biological Opinion will, given the challenges in litigation, be upheld by the courts.

Willamette River Project Biological Opinion. The Willamette River Project consists of 13 federal dams owned and operated by the Corps, located on various tributary rivers within the Willamette River Basin in western Oregon. Eight of these 13 dams have hydroelectric power turbines, generating approximately 184 annual average megawatts. The electric power from the eight hydroelectric dams is marketed by Bonneville as part of the Federal System.

Under the ESA, Bonneville, the Corps and Reclamation (the "Action Agencies") submitted a "Biological Assessment" to the Fish and Wildlife Service and NOAA Fisheries (collectively, the "Services") in April 2000. The Biological Assessment described the Willamette River Project, its operations, maintenance activities, and measures proposed to protect ESA-listed fish species that inhabit the Willamette River basin. In May 2007, the Action Agencies supplemented the original Biological Assessment with updated information on salient aspects of the original Biological Assessment. The Services issued their final biological opinions in July 2008, each having a 15-year timeframe.

Bonneville believes that the costs to achieve measures for stream flow, fish hatchery and habitat improvements, and structural changes at various dams could substantially increase its cost of power from these related dams. However, because these costs are likely to be blended in with all of the other financial obligations and revenue streams that Bonneville manages, Bonneville does not expect there to be a significant impact upon overall power rates.

Federal Repayment Offsets For Certain Fish and Wildlife Costs Borne by Bonneville. In 1995, the United States Treasury, the Office of Management and Budget, DOE and other agencies agreed to provide for certain Federal repayment credits to offset some of Bonneville's fish and wildlife costs. The foregoing agencies agreed that Bonneville would implement a previously unused provision of the Northwest Power Act, section 4(h)(10)(C). This provision authorizes Bonneville to exercise its Northwest Power Act authorities to implement fish and wildlife mitigation on behalf of all of a Federal System project's authorized purposes under Federal law; not just those relating to the delivery of generation and transmission services to customers, but also non-power purposes such as irrigation, navigation and flood control. At the end of the fiscal year, Bonneville is required to recoup (*i.e.*, take a credit for) the portion allocated to non-power purposes. Included in this credit are Direct Fish and Wildlife Program Costs and estimated Replacement Power Purchase Costs. The amount of such recoupments (also referred to as "4(h)(10)(C) credits") was about $66 million, $100 million and $99 million in Fiscal Years 2007, 2008 and 2009, respectively. Forecasts of these 4(h)(10)(C) credits are treated as revenues in Bonneville's ratemaking process. At the close of each fiscal year, they are applied against Bonneville's payments to the United States Treasury. The 4(h)(10)(C) credits are initially taken based on estimates and are subsequently modified to reflect actual data. An important cost that may be recouped under section 4(h)(10)(C) is that of Replacement Power Purchases necessitated by the loss of generation arising from certain changes to hydroelectric system operations for the benefit of fish and wildlife. These costs occur annually and are highest in dry years when, historically, the output of the hydro-system is lower and market prices for power may be comparatively high. In such years, 4(h)(10)(C) credits are correspondingly higher.

Council's Fish and Wildlife Program. In 2000, the Council revised and adopted a new Columbia River Basin Fish and Wildlife Program (the "2000 Program"). The Council amended 57 sub-basin plans into the 2000 Program in 2003 with "mainstream amendments" meant primarily to address mitigation issues related to operation of the Federal System. In 2005, the Council amended the 2000 Program to help focus mitigation actions on overcoming environmental limitations to increased fish and wildlife populations. In October 2007, the Council began the formal rulemaking process to amend the program as required by the Northwest Power Act. The Council adopted a revision to the program in February 2009.The 2000 Program emphasizes an ecosystem approach to rebuilding fish and wildlife in the Columbia River basin. The Council sets forth an "integrated program" that integrates mitigation recommendations from both the 2000 Program created under the Northwest Power Act and recovery actions needed for Bonneville to comply with the ESA. 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." For the 2007-2009 Rate Period, Bonneville originally forecasted an average expense accrual budget level of $143 million per year for the expense portion of the Integrated Program, and $36 million per year for the capital portion. With the successful conclusion of the Columbia Basin Fish Accords and the expected implementation of the final 2008 Columbia River System Biological Opinion and the Willamette River Project Biological Opinion, the Integrated Program expense spending grew to $178 million in Fiscal Year 2009 and the expense budget is expected to average $225 million per year in the 2010-2011 Rate Period. The capital program investments are expected to average $60 million per year in the same period.

Bonneville cannot provide assurance as to the scope or cost of future measures to protect fish and wildlife affected by the Federal System, including measures resulting from current and future listings under the ESA, current and future biological opinions or amendments thereto, future Council Programs or amendments thereto, or litigation relating to the foregoing.

Power Rates for Fiscal Years 2010 through 2011

Bonneville completed the 2010-2011 Final Power and Transmission Rate Proposal and submitted it, together with supporting documentation, to FERC on August 1, 2009. FERC has granted final approval of the transmission rates portion of the 2010-2011 Final Power and Transmission Rate Proposal. It granted interim approval of the power rates portion on September 28, 2009. Final FERC approval of Bonneville's power rates, which typically takes over a year from the date of submission, has not yet been received. Consistent with past practice, Bonneville's power rates proposal is based on achieving a 95% probability over the two-year rate period of making full and timely payments to the United States Treasury. Bonneville pays the United States Treasury only from net proceeds, meaning amounts in the Bonneville Fund remaining after payment of non-federal payment obligations. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

PF Rates. Most of Bonneville's power sales are made to Preference Customers to meet their net requirements under specified types of service: Block, Slice, Partial Requirements and Full Requirements. These power products and services are provided at Bonneville's lowest, statutorily-designated, cost-based power rate class, the PF Rate. PF Rates in general reflect the cost of resources and other services provided to serve the Preference Customers' net requirements loads and, except with respect to the Slice rate, reflect the benefit of revenues from sales by Bonneville of seasonal surplus (secondary) energy. In the case of the Slice product, the participating customers receive a percentage share of the seasonal surplus energy of the Federal System and hence the Slice rate does not reflect the revenues Bonneville receives from its marketing of seasonal surplus energy. The Slice rate also does not incorporate the costs or risks associated with power supply and power purchase costs, which are borne directly by Slice customers. While each of the foregoing services is provided under PF Rate schedules, the applicable rate level depends on Bonneville's rate design and specific costs to provide the related service.

PF Rates for Full Requirements service are proposed to be $28.77 per megawatt hour, which is about seven percent higher than in Fiscal Year 2009. PF Rates do not include receipt by Preference Customers of certain payments and power bill credits from Bonneville that correct prior overpayments of Residential Exchange benefits. Nor do the PF Rate level estimates include the cost of transmission service, conservation credits and certain other adjustments.

With respect to the Slice portion of Slice/Block service, Slice Rates are proposed to be $1,962,525 per percentage point of Slice under the power rates proposed for the Fiscal 2010-2011 Rate Period. (Slice Customers do not pay a rate based on average megawatts provided; rather they pay a rate that is based on a proportion of Bonneville's costs of generation.) This represents a rate increase of about 4.8 percent. Unlike rates for Requirements service and Block service, Slice rates do not incorporate the costs of risks associated with power supply, secondary sales and power purchase costs. These are borne directly by Slice customers. Slice is a combined power product that includes sales in respect of the participating customers' net requirements and sales of secondary energy. As with prior power rate proposals, Slice power rates would not be subject to the proposed CRAC, described below, because Slice rates recover actual costs. For a description of Slice of the System, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Loads and Related Contracts and Power Rates through Fiscal Year 2011—Loads and Resource Expectations in Operating Years 2010 and 2011—Preference Customer and Federal Agency Loads."

By law, the PF Rates are also the basis for two other important Bonneville rates: (i) the PF Exchange Rate (referred to herein as the "Residential Exchange Rate"), which is used to determine Residential Exchange benefits, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program," and (ii) the Industrial Power Rate, for service to DSIs. PF Rates, including Slice rates, are also established to recover the net costs of the Residential Exchange Program. Preference Customers bear such costs in PF Rates, including Slice rates. The IP Rate is based upon the PF Rate in a manner in which the IP Rate also serves to recover costs of Residential Exchange Program benefits.

Residential Exchange. With respect to the Residential Exchange, the final proposal assumes an average of $255 million per year in benefits to the residential and small-farm consumers of Regional IOUs and about $11 million per year to potential exchanging Preference Customers during the 2010-2011 Rate Period. Under the final proposal, the Residential Exchange Rate is about $48.68 per megawatt hour (including transmission).

As noted, the proposed rates do not reflect adjustments to Preference Customers' power bills and Residential Exchange benefits payments made to correct for past overpayments of Residential Exchange Program benefits to Regional IOUs. Bonneville proposes to decrease actual payments to Regional IOUs under the Residential Exchange program by about an aggregate $82 million per year during the 2010-2011 Rate Period as part of the program to recoup past overpayments of Residential Exchange Program benefits. Bonneville also expects to credit Preference Customers' power bills in like amounts. Thus, under the final proposal, Bonneville would make $173 million per year on average over the two-year rate period in payments to Regional IOUs for Residential Exchange benefits. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

DSIs. With respect to DSIs, the Final 2010-2011 Power and Transmission Rate Proposal assumed that Bonneville would provide the DSIs with service having a net cost to Bonneville of about $37 million per year. Subsequent to the completion by Bonneville of the Final 2010-2011 Power and Transmission Rate Proposal, the Ninth Circuit Court issued an opinion holding that Bonneville must show benefits in its power sales to DSIs. Bonneville later entered into two contracts with DSIs under the IP Rate of $34.60 per megawatt hour (excluding transmission service). Bonneville entered into these contracts after the court opinion and upon concluding that the DSI power sales will provide benefits to Bonneville. See "BONNEVILLE LITIGATION—DSI Service ROD Litigation."

Risk Management. The 2010-2011 Final Power and Transmission Rate Proposal includes assumptions regarding the mix of financial risk management tools that Bonneville will employ to meet its policy of setting rates that have a 95 percent probability of recovering Bonneville's Federal payment obligations over the two-year rate period. The 2010-2011 Final Power and Transmission Rate Proposal proposes to continue using a CRAC, which enables Bonneville to increase power rate levels at the beginning of both of the years of the two-year rate period. The CRAC would enable Bonneville to obtain up to an additional $300 million in revenues from non-Slice Preference Customers in the related fiscal year. The CRAC did not trigger for Fiscal Year 2010, but would have triggered had Bonneville forecasted that its accumulated modified net revenues from Power Services operations would drop below negative $877 million. The CRAC would also trigger for all of Fiscal Year 2011 if Bonneville were to forecast, in approximately September 2010, that its "accumulated modified net revenues" from Power Services operations would drop below negative $791 million. The proposed CRAC is similar to the CRAC included in Bonneville's Final 2007-2009 Power Rates. "Modified net revenues" are net revenues for Power Service operations after adjusting for the effects of the unrealized fair value of derivative instruments and nonfederal debt management actions that differ from rate case assumptions. Bonneville believes that Modified Net Revenues are a better reflection of Bonneville's financial results than standard accounting determinations of net revenues. "Accumulated Modified Net Revenues" are the accumulated total of Modified Net Revenues of Power Services, as measured from the beginning of Fiscal Year 2000.

The accumulated modified net revenues CRAC trigger points proposed for power rates in the Fiscal Year 2010-2011 Rate Period are different from those used for the Fiscal Year 2007-2009 Rate Period. Formerly, the CRAC trigger points equated to roughly $750 million in projected remaining reserves in the Bonneville Fund available for risk attributable to Power Services operations. The CRAC trigger points proposed for power rates in the Fiscal Year 2010-2011 Rate Period equate to roughly zero projected remaining reserves in the Bonneville Fund available for risk attributable to Power Services operations. The primary reason Bonneville has proposed to change the trigger point is that Bonneville's line of credit with the United States Treasury to meet certain operating expenses was increased from $300 million to $750 million, thereby diminishing Bonneville's need to carry large cash balances in the Bonneville Fund for payment assurance. Additionally, Bonneville was able to decrease the CRAC threshold (making it less likely to trigger) because the two-year Treasury Payment Probability was over two percentage points higher than the 95 percent minimum Treasury Payment Probability specified in Bonneville's Financial Plan. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Financial Plan."

In the Final 2010-2011 Power and Transmission Rate Proposal, Bonneville proposes to continue a modified version of the "NFB Adjustment," which was included in Bonneville's power rates for the Fiscal Year 2007-2009 Power Rate Period. Under the new NFB Adjustment, the cap of $300 million in additional revenues that Bonneville can recover in a fiscal year under the CRAC would be subject to increase to cover the costs of certain potential adverse events related to the current litigation over the 2008 Columbia River System Biological Opinion, should such events occur. These potential events relate primarily to the risk that the court may order changes in hydro-operations that decrease power sales or increase power purchases. The Final 2010-2011 Power and Transmission Rate Proposal also includes a version of the "NFB Emergency Surcharge," which was also included in Bonneville's power rates for Fiscal Years 2007-2009. This surcharge would allow Bonneville to increase power rate levels at any time in the 2010-2011 Rate Period in order to recover certain costs that could arise from the litigation over the 2008 Columbia River System Biological Opinion, provided that Bonneville determines that its United States Treasury payment probability has fallen below 80 percent for the fiscal year in which the costs arise.

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 open transmission access rules, to reach new sources of supply, leaving behind unamortized power system costs incurred on their behalf. Bonneville could also face this concern. While Bonneville has separate statutory authority requiring it to assure that its revenues are sufficient to recover all of its costs, additional authority may be required to assure that such costs, including Bonneville's payments to the United States Treasury, are made on time and in full. Depending on the exact nature of wholesale and retail transmission access, it is possible that Bonneville's power marketing function may not be able to recover all of its costs in the event that Bonneville's cost of power exceeds market prices. Nonetheless, Bonneville cannot predict with certainty its cost of power or market prices.

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

Bonneville's rates for any FERC-ordered transmission service pursuant to sections 211/212 of the FPA are governed only by Bonneville's applicable law, except that no such rate shall be unjust, unreasonable or unduly discriminatory or preferential, as determined by FERC. In the opinion of Bonneville's General Counsel, provisions of the Northwest Power Act directing Bonneville to recover its total cost would be applicable to any stranded cost to be recovered by Bonneville were Bonneville ordered by FERC to provide transmission under sections 211/212.

Shortly after the issuance of Order 888, Bonneville requested clarification of the application of FERC's stranded cost rule to Bonneville in the context of an order for transmission service under sections 211/212. In FERC Order 888-A, modifying original FERC Order 888, FERC addressed Bonneville's request by stating: "We clarify that our review of stranded cost recovery by [Bonneville] would take into account the statutory requirements of the Northwest Power Act and the other authorities under which we regulate [Bonneville] . . . and/or section 212(i), as appropriate." Therefore, it remains unclear how FERC would intend to balance Bonneville's Northwest Power Act cost recovery standards with the stranded cost rule as enunciated in FERC Order 888 in the context of FERC-ordered transmission service pursuant to sections 211/212. Contrary to the opinion of Bonneville's General Counsel, several of Bonneville's transmission customers have taken the position that transmission rates may not be set to recover stranded power costs as Bonneville envisions under the Northwest Power Act.

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

TRANSMISSION SERVICES

Bonneville provides a number of different types of transmission services to 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 25 percent of Bonneville's revenues from external customers (and excluding revenues otherwise arising from inter-functional transactions between Bonneville's Transmission Services and Power Services) in Fiscal Year 2009.

Bonneville's Transmission Services provides transmission service under FERC's *pro forma* Open Access Transmission Tariff. Two reservation based transmission services are offered under the Tariff: Point-to-Point and Network Integration. These services are available to all customers regardless of whether they are transmitting Federal or non-Federal power. Network Integration service is used by many Bonneville Preference Customers for delivery of primarily Federal power to their loads. Point-to-Point service is taken typically by marketers, independent power producers and certain large utility customers. Finally, Bonneville, as a partial owner of the northern portions of Southern Intertie and southern portions of certain transmission lines connecting areas of western Canada with the Region, provides Point-to-Point service to power marketers, including Bonneville's Power Services, which use Bonneville transmission service to effect power sales and related transactions inside and outside the Region. Bonneville's Transmission Services also provides reservation-based service under "legacy contracts" that were in effect when Bonneville adopted open access in the mid-1990's. As these contracts expire, the service converts to open access.

It is difficult to generalize as to the cost of transmission service needed to effect various power transactions because the rate per megawatt hour of transmission is highly dependent on actual usage and thus can vary substantially from time to time and from customer to customer. Nonetheless, a useful point of reference for the proportion that power rates bear to transmission and ancillary services rates may be the cost borne by certain Preference Customers that purchase Full Requirements power from Bonneville. These customers pay roughly \$4.00 to \$4.50 per megawatt hour for Network Integration transmission and the two ancillary services that are required to provide delivery of Full Requirements power. By contrast, Bonneville's PF Rate level for Full Requirements power under the Final 2009-2011 Power and Transmission Rate Proposal is about $28.77 per megawatt hour (exclusive of transmission). Other customers, such as Regional IOUs, and extra-Regional utilities, and marketers using Point-to-Point service to transmit non-Federal power, pay a fixed monthly charge of approximately $1.80 to $2.50 per megawatt hour for transmission and two required ancillary services, although the effective rate in terms of cost per megawatt hour of delivered energy depends on the actual transmission usage.

Bonneville's Federal Transmission System

The Federal System includes the Federal Transmission System that is owned, operated and maintained by Bonneville as well as the Federal hydroelectric projects and certain non-Federal power resources. The Federal Transmission System is composed of approximately 15,000 circuit miles of high voltage transmission lines, and approximately 300 substations and other related facilities that are located in Washington, Oregon, Idaho, and portions of Montana, Wyoming and northern California. The Federal Transmission System includes an integrated network for service within the Pacific Northwest ("Network"), and approximately 80 percent of the northern portion (north of California and Nevada) of the combined Southern Intertie. The Southern Intertie consists of three high voltage Alternating Current ("AC") transmission lines and one Direct Current ("DC") transmission line and associated facilities that interconnect the electric systems of the Pacific Northwest and Pacific Southwest and provide the primary bulk transmission link between the two regions. The rated transfer capability of the Southern Intertie AC in the north to south direction is 4,800 megawatts of capacity, and in the south to north direction is 3,675 megawatts of capacity. The rated transfer capability of the DC line in both directions is 3,100 megawatts. The operating transfer capability (or reliability transfer capability) of these facilities varies by generation patterns, weather conditions, load conditions and system outages.

The Federal Transmission System is used to deliver Federal and non-Federal power between resources and loads within the Pacific Northwest, and to import and export power from and to adjacent regions. Bonneville's Transmission Services provides transmission services and transmission reliability (ancillary) services to many customers. These customers include Bonneville's Power Services 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, maintenance, and expansion to maintain electrical stability and reliability of the system. As a matter of policy, Bonneville's transmission planning and operation decisions are guided by internal, regional and national reliability practices. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005" for a discussion of new statutory provisions relating to reliability criteria.

Bonneville continually monitors the Federal Transmission System and evaluates cost-effective reinforcements needed to maintain electrical stability and reliability of the system on a long-term planning basis. A number of conditions, actions, and events could affect the electric transfer capability of the Federal Transmission System and diminish the capacity of the system. For example, operating conditions such as weather, system outages and changes in generation and load patterns may reduce the reliability transfer capability of the transmission system in some locations and limit the capacity of the system to meet the needs of users of the Federal Transmission System, including Bonneville's Power Services. To assure that the Federal Transmission System is adequate to meet transmission needs, Transmission Services evaluates system performance to determine whether or not to make transmission infrastructure investments.

While in the recent past Bonneville has focused its transmission infrastructure efforts on transmission projects needed to maintain reliability, other transmission projects are now being undertaken or proposed that will provide additional, long-term firm transmission service for those seeking new transmission service in the Region, especially those developing new power generation projects both inside and outside the Region. Under Bonneville's policies, certain qualifying entities, referred to as "Eligible Customers," may request that Bonneville provide transmission service across the Federal Transmission System and in some circumstances, Bonneville may have to build or install transmission facilities to provide the requested transmission service. Bonneville does not believe that it is subject to FERC regulation in the funding of such investments; nonetheless, as a policy matter Bonneville has sought FERC findings that Bonneville's policies and tariff terms relating to providing transmission service are consistent with FERC policy.

Depending on the circumstances, Bonneville may seek prepayment of its costs for the related investments from the Eligible Customers seeking the transmission service. In many such instances, in particular where the related facilities are included in Bonneville's network, Bonneville may return, over time, to the Eligible Customers the amounts they advanced to Bonneville for the related new facilities. Bonneville may provide these returns in the form of (i) credits against billings by Bonneville for firm transmission service purchased from Bonneville at established transmission rates, or (ii) in the case of new facilities to interconnect large new generation projects to the network, cash payments to the generator or its assigns. The payments and credits by Bonneville are intended to permit the Eligible Customer to recoup the funds it provides to Bonneville.

In some circumstances, Bonneville may not seek any prepayment for transmission investments from the Eligible Customer and may allocate all of the costs of new facilities to network service rates, thereby socializing the costs among all network customers. Even where Bonneville does not seek prepayment, Bonneville may determine to charge the Eligible Customer an "incremental cost" rate for transmission service, which is higher than Bonneville's embedded cost rate, in order for Bonneville to protect other customers from costs they would otherwise bear due to the provision by Bonneville of the new service. Bonneville may allocate some of the facilities' costs to other network customers under embedded cost rates if they are benefited by the new facilities, in particular where the new facilities lead to the avoidance of construction of other new facilities for reliability purposes.

FERC has approved a proposal by Bonneville through which Bonneville will seek to identify the extent Eligible Customers, including developers of proposed new generation such as wind generation, will actually make long-term, creditworthy commitments for transmission service that require new network transmission system investments. Bonneville believes that this process will assist Bonneville in assuring it will recover the costs of investing in related transmission facilities and help avoid stranded transmission investments.

As this process unfolds, and Bonneville identifies the potential for financing such investment with means other than the customer-funded approaches relied on in the past, Bonneville may incur new, indirect, non-Federal debt obligations. Bonneville is unable to predict the cost of new investments for the integration of new generation or to meet other Eligible Customers' transmission service requests, the amount that will actually be committed to by Eligible Customers on terms acceptable to Bonneville, or the extent to which Bonneville will fund such investments through customer advances of funds, borrowing from the United States Treasury, or third-party debt, such as lease-purchases.

In Fiscal Year 2009, Bonneville provided about $17 million in transmission payment credits as offsets for amounts advanced to Bonneville for new transmission integration investments. Bonneville expects that the amount of such credits could increase in coming years because of expected increases in the development of generation projects (particularly wind projects) that will need transmission service over the Federal Transmission System.

Bonneville's current transmission system investment plan calls for Bonneville to make investments in Fiscal Years 2010 through 2015 averaging about $525 million annually. To finance the foregoing investments, Bonneville expects to use United States Treasury borrowing, reserves and advance payments from generation integration and transmission customers. Bonneville also expects to use long-term, capitalized lease-purchase arrangements to acquire transmission infrastructure facilities as a means of reducing the pressure on Bonneville's United States Treasury borrowing authority.

With DOE policy approval, Bonneville entered into a long-term, capitalized lease-purchase agreement with Northwest Infrastructure Financing Corporation ("NIFC") in 2003 with respect to a large transmission line project located in Washington State. NIFC issued about $120 million in bonds to fund construction of the project. The bonds are secured solely by NIFC's pledge of Bonneville's lease payments under the project lease.

Subsequently, Bonneville entered into three separate master lease agreements with affiliates of NIFC under which Bonneville has entered into lease-purchase commitments to finance $325.5 million in aggregate Federal Transmission System replacements and improvements, as of the end of Fiscal Year 2009. Under each of the master lease arrangements, Bonneville's lease-purchase payments are pledged to the payment of bank loans incurred by the respective project owner. The proceeds of the loans are used to finance the construction and installation of the leased facilities. Bonneville's lease payments are not conditioned on the completion, suspension or termination of the related projects and the principal amounts associated with the bank loans are included in Federal System audited financial statements as "Non-Federal Debt." Bonneville estimates potential third-party financing averaging about $56 million annually over Fiscal Years 2010-2015. The actual value could be higher or lower depending on capital spending in such years and other factors. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Financial Plan."

Non-discriminatory Transmission Access and Separation of Power Services and Transmission Services

In general, the thrust of regulatory changes in the 1990s, both by Congress and FERC, has been to require transmission owners to provide open transmission access to their transmission systems on terms that do not discriminate in favor of the transmission owner's own power-marketing functions. EPA-1992 amended sections 211/212 of the FPA to authorize FERC to order a "transmitting utility" to provide access to its transmission system at rates and upon terms and conditions that are just and reasonable, and not unduly discriminatory or preferential.

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

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

Bonneville is a non-jurisdictional utility. Notwithstanding the limited applicability of FERC Order 888 to Bonneville, however, since 1996, Bonneville has voluntarily adopted terms and conditions for a non-discriminatory open access transmission tariff and filed such tariff with FERC seeking a reciprocity order. Bonneville's tariff offers transmission service to Bonneville's Power Services and to other transmission users at the same tariff terms and conditions, and at the same rates. Bonneville's current open access transmission tariff became effective October 1, 2001 and, as amended, remains in effect indefinitely. The tariff has received FERC approval. Bonneville will continue to update the tariff as appropriate to reflect changes FERC makes to its *pro forma* open access tariff. Bonneville is in the process of adopting changes in its tariff to reflect relatively recent changes in FERC's *pro forma* tariff.

EPA-2005 includes provisions relating to terms and conditions of transmission service that may be imposed by an "unregulated transmitting utility" (a term that includes Bonneville). The provisions authorize FERC to require such utilities to provide transmission services to others on terms and conditions that are comparable to those the utility offers itself and that are not unduly discriminatory or preferential. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005."

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

Bonneville's Transmission and Ancillary Services Rates

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

Bonneville proposed and FERC has approved as final Bonneville's transmission, ancillary services and control area service rates for the two years beginning Fiscal Year 2010. All of the transmission rates and the two required ancillary services rates remain unchanged from the prior transmission rate period, Fiscal Years 2008-2009. Bonneville estimates that its transmission rates and the two required ancillary services for Network Service are about \$15.38 per megawatt per month, as proposed in the Final 2010-2011 Power and Transmission Rate Proposal.

In the Final 2010-2011 Power and Transmission Rate Proposal, Bonneville adopted a rate for Wind Balancing Service to recover the costs that Bonneville bears in integrating wind resources into the Federal System. This new rate applies to wind resources to recover the costs of the reserves described above. Wind Balancing Service rate is about \$6.00 per megawatt hour of wind generation, assuming that wind energy production is about 30 percent of the installed capacity of the wind generation. The Wind Balancing Service rate is in addition to applicable rates for the transmission of power. For a discussion of wind energy integration, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Bonneville's Resource Program and Bonneville's Resource Strategies for the Post-2011 Period—Wind Generation Development and Integration into the Federal Transmission System."

Bonneville is in the informal planning stage to prepare studies, documentation and testimony that will comprise the initial rate proposal for transmission and ancillary services for the two fiscal years beginning October 1, 2011. A joint workshop schedule for power and transmission issues will be discussed with customers in early spring. The initial proposal for transmission and power is scheduled to be released in November 2010. Bonneville plans to submit its final proposed rates for power, transmission and ancillary services, together with the related record of decision, to FERC in July 2011. EPA-2005 includes provisions relating to transmission rates charged by an "unregulated transmitting utility" (a term that includes Bonneville). The provisions authorize FERC to require such utilities to provide transmission services at rates "comparable" to those the utility charges itself. Thus, FERC now has authority to require that the transmission rates Bonneville charges Power Services for transmission service to be comparable to the transmission rates Bonneville charges other customers. FERC has not yet invoked this authority. However, Bonneville has sought and received FERC approval of transmission rates under comparability standards, and with the stricter rates standards applicable to reciprocity under Order 888, since 1996.

The foregoing provisions in EPA-2005 do not amend Bonneville's existing statutory provisions under the Northwest Power Act to establish transmission rates to recover Bonneville's transmission costs. In the opinion of General Counsel to Bonneville, the foregoing EPA-2005 provisions relating to Bonneville's transmission rates would not adversely affect Bonneville's authority and obligation to recover in full the costs of providing transmission service through its transmission rates. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005."

Bonneville's Participation in a Regional Transmission Organization

In January 2000, FERC issued a final rule on regional transmission organizations ("RTOs"), establishing minimum characteristics and functions for an RTO and requiring that each jurisdictional utility (a term that does not include Bonneville) make certain filings regarding the formation of and participation in an RTO. FERC proposed RTOs as a means to assure that transmission owners make transmission available on a basis that does not discriminate in favor of their affiliated power marketing activities. Following the FERC actions to promote RTOs, transmission owning utilities in the Region and others attempted to develop an RTO that would assist transmission operations in the Region. None of those proposals have been implemented. FERC has now decided that participation in RTOs will be voluntary. EPA-2005 includes provisions explicitly authorizing Bonneville to participate in the formation and operation of an RTO. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005."

Bonneville is currently pursuing an approach to implement "ColumbiaGrid," with six transmission owners that are control area operators in the West. Compared to prior RTOs that have been proposed for the Region, ColumbiaGrid would not qualify as an "RTO" under FERC policies since ColumbiaGrid has a relatively restricted scope of operations. By contrast to an RTO, ColumbiaGrid focuses on coordinating Regional transmission planning and expansion, assisting participating utilities in meeting their transmission reliability obligations, and operating an information system ("OASIS") to provide power marketers and others with information about transmission system operations. It is possible in the long run that ColumbiaGrid would have increased operational control of the related transmission assets and take an increased role in providing transmission service, including through the operation of transmission markets and market monitoring. Whether ColumbiaGrid's scope of operations evolves to include new functions will be determined by the participating utilities in the future.

Bonneville has entered into agreements to fund a proportionate interest of the costs of making ColumbiaGrid operational, to assist ColumbiaGrid in efficient transmission planning and expansion in its service area, and to operate a common OASIS with implementation beginning in 2009. Bonneville's estimates that its expense associated with the foregoing and other existing arrangements with ColumbiaGrid will be about $3 million per year.

ColumbiaGrid and its members are also participating with the members of two other groups of transmission owners in a "Joint Initiative," which is exploring approaches to deal with the challenges associated with integrating large amounts of intermittent generating resources, such as wind power, into the resource mix within the transmission system of Western North America. The provision of ancillary services to support these resources can be managed by certain, more efficient scheduling practices, which can be achieved only by the development of communication protocols and business practices within and across western control areas. Although agreements to implement the results of this Joint Initiative have yet to be executed, significant progress has been made.

Bonneville and the other participants in ColumbiaGrid continue to work on the development of ColumbiaGrid's operations.

MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES

Bonneville Ratemaking and Rates

Bonneville Ratemaking Standards

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

Bonneville Ratemaking Procedures

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

Federal Energy Regulatory Commission Review of Rates Established by Bonneville

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

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

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

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

For a discussion of FERC rate review and regulation related to transmission access and rates, see "TRANSMISSION SERVICES—Non-discriminatory Transmission Access and Separation of Power Services and Transmission Services" and "—Bonneville's Transmission and Ancillary Service Rates."

Judicial Review of Federal Energy Regulatory Commission Final Decision

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

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

Power Customer Classes

The Northwest Power Act, as well as other Bonneville organic statutes, provides for the sale of power: (1) to Preference and certain Federal agency customers; (2) to DSIs; and (3) for those portions of loads which qualify as "residential," to investor-owned and public utilities participating in the Residential Exchange Program. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program." The rates for power sold to these respective customer classes are based on allocation of the costs of the various resources available to Bonneville, consistent with the various statutory directives contained in Bonneville's organic statutes.

Other Firm Power Rates

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

Surplus Energy

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

Limitations on Suits against Bonneville

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

Laws Relating to Environmental Protection

Bonneville must comply with the National Environmental Policy Act ("NEPA"), which requires that Federal agencies conduct an environmental review of a proposed Federal action and prepare an environmental impact statement if the action proposed may significantly affect the quality of the human environment. NEPA may require that Bonneville follow statutory procedures prior to deciding whether to implement an action. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), the Resource Conservation and Recovery Act ("RCRA"), the Toxic Substance Control Act ("TSCA") and applicable state statutes and regulations, as well as amendments thereto, may result in Bonneville incurring unplanned costs to investigate and clean up sites where hazardous substances have been released or disposed of. Bonneville has been identified as one of several potentially responsible parties at one site. Bonneville's environmental protection costs at this site are approximately $200,000 to date. Additional costs for the remedial investigation at the site are possible during 2010. Bonneville has not committed to any cleanup at this time pending a Record of Decision in 2010. EPA estimates of potential cleanup costs are $1-2 million, which would be shared among a number of parties.

Energy Policy Act of 2005

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

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

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

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

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

Other Applicable Laws

Many statutes, regulations and policies are or may become applicable to Bonneville, several of which could affect Bonneville's operations and finances. Bonneville cannot predict with certainty the ultimate effect such statutes, regulations or policies could have on its finances.

Columbia River Treaty

Bonneville and the Corps have been designated by executive order to act as the "United States Entity" which, in conjunction with a Canadian counterpart, the "Canadian Entity," formulates and carries out operating arrangements necessary to implement the 1964 Columbia River Treaty (the "Treaty"). The United States and Canada entered into the Treaty to increase reservoir capacity in the Canadian reaches of the Columbia River basin for the purposes of power generation and flood control.

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

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

The United States Entity and Canadian Entity 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 in 1999.

Although the Treaty itself does not expire by its own terms, either the United States or Canada may elect to terminate it by providing not less than ten-years' notice, with the earliest time for termination occurring in calendar year 2024. Bonneville has not received any indication from either the United States or Canada of any interest in terminating the Treaty.

Proposals for Federal Legislation and Administrative Action Relating to Bonneville

Congress from time to time considers legislative changes that could affect electric power markets generally and Bonneville specifically. For example, several bills have proposed, among other things, granting buyers and sellers of power access to Bonneville's transmission under a form of regulatory oversight comparable to that currently applicable to privately-owned transmission and subjecting Bonneville's transmission operations and assets to FERC regulation. Under this type of regulation, in general, a transmission owner may not use its transmission system to recover costs of its power function. This type of regulation would be at odds with Bonneville's General Counsel's legal opinion of Bonneville's current transmission rate authority under which Bonneville would, if necessary, be required to use transmission rates to recover its power function costs. Other proposals advanced in or submitted to Congress have included privatizing the Federal power marketing agencies, including Bonneville, privatizing new and replacement capital facilities at Federal hydroelectric projects, studying the removal of certain federally-owned dams of the Federal System, placing caps on Bonneville's authority to incur certain types of capitalized costs, requiring that Bonneville sell its power at auctioned market prices rather than under cost-based rates, and limiting Bonneville's ability to incur new third party debt.

In calendar year 2009, the United States Senate and the United States House of Representatives passed separate bills to reform the financial industry in the United States. The bills have not become law. The bills have substantial differences, but, in general, both would increase regulatory oversight of financial transactions, in particular over-the-counter swaps, futures, options and derivatives. The scope of regulation under both bills is very broad, and would grant extensive discretion to applicable regulatory bodies to establish and enforce rules and requirements for participants in a wide range of commercial and financial markets. Regulation under the bills could lead to the imposition of trading limits, and capital, reserve, and collateral requirements (primarily margin requirements) either directly or through mandatory clearing on regulated exchanges. Increased regulation could also result in reduced flexibility of counterparties to develop unique transactions.

Bonneville participates extensively in over-the–counter electric power transactions, almost all of which call for physical delivery of electric power. Bonneville also has entered into financial interest rate swaps. Finally, Bonneville is considering entering into exchange traded power-related financial transactions that do not call for physical delivery. Depending on the terms of enacted regulatory reform legislation and implementing rules, it is possible that Bonneville's trading and financial operations could be affected.

Bonneville cannot predict whether these or any other proposals relating to it will be enacted or implemented. Nor can Bonneville predict the terms any future proposals or laws may include. It is possible that such future proposals, if enacted or implemented, could affect Bonneville's ability to perform its obligations with respect to the Series 2010 Bonds.

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

Climate Change

Federal, regional, state, and international initiatives have been proposed or adopted to address global climate change by controlling or monitoring greenhouse gas emissions, by encouraging renewable energy development and by implementing other measures. Bonneville cannot predict whether or when new laws and regulations or proposed initiatives would take effect in a manner that would affect Bonneville, and, if so, how they would affect Bonneville.

One of the major climate change policy initiatives being discussed at the national and regional levels is the pricing of carbon either through a cap and trade or a carbon tax. The pricing of carbon is intended to disfavor the use of high carbon intensity resources, particularly coal. However, none of the generating facilities of the Federal System are fueled by carbon-based fuels. The Federal System generating facilities are primarily hydroelectric resources, or, in the case of Columbia Generating Station, nuclear-fueled.

Bonneville frequently enters into short-term agreements for the purchase of electric power to make "balancing purchases" in periods of the year when Federal System generating facilities are not expected to be able to match loads. Further, in the past Bonneville has entered into and in the future expects to enter into similar market purchases in order to address longer term firm power deficits. To the extent that the electric power that Bonneville purchases for these purposes is derived from carbon-based generation, Bonneville could face increased costs if and when carbon emission regulation takes effect. However, Bonneville believes that cost increases in purchases would likely be offset by an increase in the relative value of its non-carbon-based seasonal surplus (secondary) energy, which is derived primarily from hydroelectric generating resources. In any event, given the predominance of non-carbon-based generation in the Federal System, to the extent that global warming initiatives impose controls or costs on carbon generation, Bonneville believes that the aggregate relative economic value of Bonneville's electric power probably would not decline, all else being equal.

To the extent that new regulations and incentives for non-carbon based generation increase the development of new generation facilities, Bonneville could face increased costs for integrating such facilities into the Federal Transmission System. However, Bonneville would be required by law to recover the costs in transmission and related rates. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Bonneville's Resource Program and

Bonneville's Resource Strategies for the Post-2011 Period—Wind Generation Development and Integration into the Federal Transmission System." There may also be pressure to retire certain high carbon intensity resources early, particularly coal-fired generation. Given the resource profile of the Federal System it is unlikely that the resources that produce power marketed by Bonneville will be closed early as a result of climate change policy.

The physical effects of climate change could affect the generation capability of the Federal System to meet loads. Given the Federal System's reliance on precipitation and snow pack, climate change could affect the amount, timing and availability of hydroelectric generation. In addition, climate change could affect load patterns if space-heating and -cooling demands change, and if heat waves become more frequent and severe. Finally, changes in climate could adversely affect fish and wildlife populations affected by the Federal System, possibly resulting in additional costs. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

BONNEVILLE FINANCIAL OPERATIONS

The Bonneville Fund

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

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

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

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

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

The Federal System Investment

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

Bonneville is required by statute to establish rates that are sufficient to repay the Federal investment in the power facilities of the Federal System within a reasonable period of years. The statutes, however, are not specific with regard to directives for the repayment of the Federal System investment, including what constitutes a reasonable period of years. Consequently, the details of the repayment policy have been established through administrative interpretation of the basic statutory requirements. The current administrative interpretation is embodied in the United States Secretary of Energy's directive RA 6120.2. The directive provides that Bonneville must establish rates that are sufficient to repay the Federal investments within the average expected service life of the facility or 50 years, whichever is less.

Bonneville develops a repayment schedule both to comply with investment due dates and to minimize costs over the repayment period. Costs are minimized, in accordance with the United States Secretary of Energy's directive RA 6120.2, by repaying the highest interest-bearing investments first, to the extent possible. This method of determining the repayment schedule would result in some investments being repaid before their due dates, while assuring that all investments will be repaid by their due dates. As of September 30, 2009, Bonneville had repaid $9.5 billion of principal of the Federal System investment and has $4.4 billion principal amount outstanding with regard to such appropriated investments and $2.1 billion principal outstanding in bonds issued by Bonneville to the United States Treasury.

Bonneville's Financial Plan

In the summer of 2008 and coincident with the later stages of the development of the new long-term power sales and related agreements for the period after Fiscal Year 2011, Bonneville issued a "Financial Plan" that sets forth general guidance in several key areas of financial policy. Among the areas addressed in the Financial Plan are Bonneville's United States Treasury repayment probability, around which Bonneville develops its power and transmission rate proposals, and Bonneville's access to capital.

First, the Financial Plan continues Bonneville's practice of proposing power and transmission rates that each achieve a 95 percent probability of full and timely payment of Bonneville's related annual payment responsibilities to the United States Treasury over a two-year rate period (or an equivalent annual payment probability if Bonneville employs a rate period other than two years). Bonneville also indicated that it would propose any changes to the United States Treasury payment probability practice through a formal rate proceeding.

Second, the Financial Plan identifies Bonneville's access to capital as a key area of concern and proposes that Bonneville work toward developing a rolling 20-year horizon for assuring that its access to capital is sufficient to meet its infrastructure investment needs. Federal System infrastructure investment needs encompass, primarily, the capital programs for the hydroelectric facilities of the Federally-owned dams, fish and wildlife facilities, and the Federal Transmission System. These capital investments will enable Bonneville to meet the increasing demand for power, provide reliable and responsive transmission services, and help restore and enhance fish populations and wildlife habitat. Bonneville will develop a capital funding plan that takes into account forecasted capital investment needs, the expanded United States Treasury authority described immediately below, and other possible sources of capital such as lease-purchase financing of transmission facilities.

Increase in Bonneville's Authority to Borrow from the United States Treasury

On February 17, 2009, President Barack Obama signed into law a $3.25 billion increase in Bonneville's authority to borrow from the United States Treasury, bringing Bonneville's aggregate United States Treasury borrowing authority to $7.7 billion. This increase is to be used for the purpose of providing funds to assist in financing the construction, acquisition, and replacement of the Federal Transmission System and to implement the purposes of the Northwest Power Act. As with Bonneville's other increments of United States Treasury borrowing authority, the additional authority is available unless Congress were to enact a law to revoke it and the increased authority is revolving, meaning that as outstanding balances are paid, the authority to borrow is restored. The increase will help enable Bonneville to fund its near- and long-term capital investments. See "—Bonneville Financial Plan." Bonneville expects to attribute about $2 billion of investment in the Federal System over the next eight years to the increased United States Treasury borrowing authority described immediately above. The increase in Treasury borrowing authority will reduce the need for Bonneville to use third party sources of funding to finance new transmission assets over the next several years. To the extent that Bonneville incurs non-Federal payment obligations for associated debt, such obligations are likely to be on parity, in terms of Bonneville's statutory priority of payments, with Bonneville's payment obligations for Energy Northwest's Net Billed Project debt, including the Series 2010 Bonds.

Bonneville Borrowing Authority

Bonneville is authorized to issue and sell to the United States Treasury, and to have outstanding at any one time, up to $7.7 billion aggregate principal amount of bonds. Of the $7.7 billion in borrowing authority that Bonneville has with the United States Treasury, $2.1 billion of bonds were outstanding as of September 30, 2009. Under current law, none of this borrowing authority may be used to acquire electric power from a generating facility having a planned capability of more than 50 annual average megawatts. Of the $7.7 billion in United States Treasury borrowing authority, $1.25 billion is available for electric power conservation and renewable resources, including capital investment at the Federal System hydroelectric facilities owned by the Corps and Reclamation, and $6.45 billion is available for Bonneville's transmission capital program and to implement Bonneville's authorities under the Northwest Power Act.

The interest on Bonneville's outstanding bonds is set at rates comparable to rates on debt issued by other comparable Federal Government institutions at the time of issuance. As of September 30, 2009, the interest rates on the outstanding bonds ranged from 2.75 percent to 6.70 percent with a weighted average interest rate of approximately 4.97 percent. The original terms of the outstanding bonds vary from 3 to 34 years. The term of the bonds is limited by the average expected service life of the associated investment: 35 years for transmission facilities, 45 years for Corps and Reclamation capital investments, up to 20 years for conservation investments and 15 years for fish and wildlife projects. Bonds can be issued with call options. As of September 30, 2009, Bonneville had on its books eight callable bonds and 25 advances under the new Treasury banking arrangement (described herein under "—Banking Relationship between the United States Treasury and Bonneville") totaling in aggregate $1.104 billion.

Banking Relationship between the United States Treasury and Bonneville

Effective April 30, 2008, Bonneville entered into an Obligation Purchase Memorandum of Understanding ("Obligation Purchase MOU") establishing a new banking arrangement governing the terms by which Bonneville borrows from the United States Treasury. Formerly, there was no overarching formal documentation of the terms under which the United States Treasury would lend funds to Bonneville; rather, the banking arrangement was more informal with borrowings made on the basis of administrative practice evolved over more than 30 years. The new banking arrangement provides a process and methodology for establishing interest rates, various types of credit facilities, the terms for several types of prepayment rights, the documentation requirements for requesting advances and rescinding advances requests, and a number of other administrative details. The banking arrangement enables Bonneville to borrow for long- and short-term capital needs and to borrow for operating expenses, an ability that Bonneville had lacked previously. Under the short-term expense borrowing arrangement, as amended in Fiscal Year 2009, Bonneville may borrow and have outstanding at any one time up to $750 million in aggregate. The short-term operating advances can be made available on as short as one day's notice and have a maximum repayment period of one year, although Bonneville may extend the maturities an additional year by exercising certain rights that would re-establish applicable interest rates. Nothing in the new banking arrangement increases the statutory limit on the $7.7 billion aggregate principal amount of debt that Bonneville may issue to the United States Treasury and have outstanding at any one time.

Coincident with the entry into the Obligation Purchase MOU, Bonneville and the United States Treasury entered into an Investment Memorandum of Understanding ("Investment MOU") that governs investments in the Bonneville Fund beginning October 1, 2008. Under prior practice, Bonneville earned a credit on all cash balances in the Bonneville Fund, which credits were to be applied to interest due on Bonneville's outstanding United States Treasury bonds. The interest credit was earned at the weighted average interest rate of all outstanding bonds issued by Bonneville to the United States Treasury. Under the Investment MOU, Bonneville's ability to earn interest credits will phase-out gradually over an expected ten-year period, beginning on October 1, 2008. In lieu of earning interest credits, Bonneville will invest the applicable cash reserves in the Bonneville Fund in certain interest bearing securities issued by the United States Treasury. Bonneville expects that the fund balance interest earnings under the investment model will be lower than if Bonneville were to continue to earn interest credits on all of its balances under the prior practice.

Debt Optimization Program

In 2000, Bonneville presented a "Debt Optimization Program" to Energy Northwest. The Debt Optimization Program, which was agreed to by Energy Northwest, involves extending the final maturities of outstanding Columbia Project Net Billed Bonds coming due prior to 2013 through a series of refunding bond issues. In 2001, Energy Northwest's Executive Board adopted an updated Refunding Plan in which it also incorporated an increase in the average life of outstanding Projects 1 and 3 Net Billed Bonds by extending the maturity of such bonds for any future refinancing of such bonds. In addition, in early 2006 Energy Northwest and Bonneville agreed that certain bonds to be issued to finance new investments at the Columbia Generating Station, and certain new Columbia Generating Station refunding bonds, may have maturities through 2024. A portion of such refunding bonds was issued in connection with the Debt Optimization Program.

Bonneville manages its overall debt portfolio to meet the objectives of: (1) minimizing the cost of debt to Bonneville's ratepayers; (2) maximizing Bonneville's access to its lowest cost capital sources to meet future capital needs and minimize costs to ratepayers; and (3) maintaining sufficient financial flexibility to meet Bonneville's financial requirements. The Debt Optimization Program was intended to allow Bonneville to advance the amortization of Bonneville's United States Treasury debt and reduce Bonneville's overall fixed costs. Under the Debt Optimization Program through Fiscal Year 2009, approximately $2.6 billion in maturing and advance refundable bonds issued by Energy Northwest for the Net Billed Projects have been refinanced with new bonds having final maturities in calendar years 2013-2024.

Although Bonneville and Energy Northwest currently do not expect to undertake future Energy Northwest debt refundings for the purpose of implementing the Debt Optimization Program, Bonneville and Energy Northwest do expect to undertake future refundings which extend maturities of outstanding Energy Northwest debt. For example, the Project 1 2010-B Bonds, the Columbia 2010-B Bonds, and the Project 3 2010-B Bonds are being issued to extend final maturities of Energy Northwest debt but are not being issued as part of the Debt Optimization Program. The purpose of these future refundings is expected to be to extend final Energy Northwest debt maturities in order to enable Bonneville to maintain financial flexibility to meet its financial requirements and to reduce Bonneville's overall fixed costs.

Order in Which Bonneville's Costs Are Met

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

Bonneville is required to make certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System other than those used to make payments to the United States Treasury for: (i) the repayment of the Federal investment in certain transmission facilities and the power generating facilities at Federally-owned hydroelectric projects in the Pacific Northwest; (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury; (iii) repayment of appropriated amounts to the Corps and Reclamation for costs that are allocated to power generation at Federally-owned hydroelectric projects in the Pacific Northwest; and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its Fiscal Year 2009 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments of $845 million in Fiscal Year 2009, approximately $234 million was 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 the Debt Optimization Program through the use of cash flows derived from reduced debt service in such fiscal year for the Project 1, Project 3 and the Columbia Generating Station. Such United States Treasury prepayments were payments in addition to the amounts that United States Treasury repayment criteria applicable to Bonneville ratemaking would cause to be scheduled for payment. In accordance with the Debt Optimization Program, Bonneville plans to make similar advance amortization payments to the United States Treasury at least through Fiscal Year 2012. See "—Debt Optimization Program."

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all non-United States Treasury cash payment obligations of Bonneville, including: cash deficiency payments, if any, under the Net Billing Agreements securing the Series 2010 Bonds; payments, if any, under the 1989 Letter Agreement; payments under the Direct Pay Agreements; and, other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including cash deficiency payments under the Net Billing Agreements securing the Series 2010 Bonds, payments, if any, under the 1989 Letter Agreement, payments under the Direct Pay Agreements, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See the Official Statement under "SECURITY FOR THE NET BILLED BONDS—Net Billing and Related Agreements—General" and "—Direct Pay Agreements" and see "—Direct Pay Agreements" in this Appendix A.

Bonneville is authorized to enter into new agreements to provide for additional net billing of its customers' bills. Nevertheless, because Bonneville is now able to enter into contractual obligations requiring cash payments that exceed, at the time the obligation is created, the sum of the amount in the Bonneville Fund and available borrowing authority, the primary reason for using net billing no longer exists. Bonneville has no present plans to enter into new agreements with Net Billing Agreement Participants ("Participants") requiring net billing to fund resource acquisitions or other capital program investments. For a description of the Net Billing Agreements, net billing and Participants, see the Official Statement under "SECURITY FOR THE NET BILLED BONDS."

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

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

Direct Pay Agreements

In Fiscal Year 2006, Bonneville and Energy Northwest entered into certain Direct Pay Agreements. Under these agreements, Bonneville has agreed by contract to pay directly to Energy Northwest the costs of Columbia Generating Station, Project 1 and Project 3 as billed to Bonneville by Energy Northwest. Under these agreements, Bonneville's cash receipts and payments are more efficiently matched so that Bonneville may reduce the cash balance it carries in the Bonneville Fund to assure full and timely payment of its obligations, both Federal and non-Federal.

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

By reducing the amount of net billing credits, Bonneville receives and will receive more revenues in cash from Participants during times of the year when Bonneville would otherwise carry its lowest annual cash balances, typically after Bonneville makes its end-of-fiscal-year payments to the United States Treasury. Under the Direct Pay Agreements, Energy Northwest's revenues with respect to the Net Billed Projects are and will be received throughout the year rather than predominantly in the early months of Energy Northwest's fiscal year (July 1–June 30), and have resulted and will result in higher cash balances in the Bonneville Fund at the end of each Bonneville fiscal year. As a consequence of re-shaping its annual cash flow patterns under the Direct Pay Agreements, Bonneville has been able to adopt lower power rate levels than would have been expected in the absence of the Direct Pay Agreements. Bonneville believes that these beneficial power rate effects will persist so long as the Direct Pay Agreements remain in effect and are complied with.

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

Although the payments to Energy Northwest under the Direct Pay Agreements remain included under the respective pledge of revenues for related series of Net Billed Bonds, such agreements are not pledged to secure the payment of, nor are they security for, the related series of Net Billed Bonds and are subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest.

In the event that payments under the Direct Pay Agreements were to fall short of meeting Net Billed Project costs or the Direct Payment Agreements were terminated, under the Net Billing Agreements, the Participants would resume making payments directly to Energy Northwest and Bonneville would resume crediting (net billing) amounts otherwise due to Bonneville by the Participants for power and transmission purchases from Bonneville, up to the amount of payments made by the Participants to Energy Northwest. See, in the Official Statement, "SECURITY FOR THE NET BILLED BONDS—Net Billing and Related Agreements—Payment Procedures." In general, the amount of the Participants' payments subject to net billing is based on the amount of transmission and power purchased from Bonneville and the rates levels charged by Bonneville for such purchases.

Direct Funding of Federal System Operations and Maintenance Expense

In 1992, Congress enacted legislation authorizing but not requiring the Corps and the Department of Interior, encompassing both Reclamation and the Fish and Wildlife Service, to enter into direct funding agreements with Bonneville for operations and maintenance activities for the benefit of the Federal System. Under direct funding, periodically during the course of each fiscal year, Bonneville pays amounts directly to the Corps or the Department of Interior for operations and maintenance of their respective Federal System hydroelectric facilities as the Corps or the Department of Interior and Bonneville may agree. Bonneville now "direct funds" virtually all of the Corps and Reclamation Federal System operations and maintenance activities. Bonneville's cash payments for the Corps, Reclamation, and the Fish and Wildlife Service in Fiscal Year 2009 were $156 million, $78 million, and $21 million, respectively.

Bonneville believes that, in contrast to prior practice, the direct funding approach increases Bonneville's influence on the Corps' and the Department of Interior's Federal System operations and maintenance activities, expenses and budgets because, in general, Bonneville's approval is necessary for the Corps and the Department of Interior to assure funding. Under the direct funding agreements, direct payments from Bonneville for operations and maintenance are subject to the prior application of amounts in the Bonneville Fund to the payment of Bonneville's non-Federal obligations, including Bonneville's payments, if any, with respect to the Net Billed Projects. Notwithstanding the foregoing, as a practical matter, since direct funding would be made by cash disbursement from the Bonneville Fund during the course of the year rather than as a repayment of a loan at the end of the year, it is possible that direct funding could be made to the exclusion of non-Federal payments that would otherwise have been paid under historical practice. A result of any direct funding obligation by Bonneville is that there has been and will be a reduction in the amount of Federal System operations and maintenance appropriations that Bonneville would otherwise have to repay, thereby reducing the amount of Bonneville's repayments to the United States Treasury that would otherwise be subject to deferral. Nonetheless, Bonneville expects to have roughly $600 million to $800 million in scheduled payments each year to the United States Treasury, exclusive of the Corps' and the Department of Interior's operation and maintenance expenses through Fiscal Year 2013. Bonneville expects that it will renew and extend the direct funding agreements with the Corps, Reclamation and Fish and Wildlife Service prior to the expiration dates of the respective agreements.

Position Management and Derivative Instrument Activities and Policies

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

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

Bonneville has used interest rate swaps to manage interest rate costs and risks. On February 24, 2010, Bonneville terminated two separate floating-to-fixed interest rate swaps that it entered into in 2003. These swaps had an aggregate notional amount of $399 million, approximately equal to the principal amount of certain variable rate bonds issued by Energy Northwest (the "Related Bonds"). The Related Bonds are being refunded by Energy Northwest with certain proceeds from the Series 2010 Bonds. See "PURPOSE OF ISSUANCE—Refunding Bonds" in the Official Statement. To terminate the swaps, Bonneville has agreed to pay the swap providers about $31 million, in aggregate. While Bonneville no longer has any interest rate related swaps in effect, it is possible that Bonneville may enter into such transactions in the future.

Bonneville does not currently undertake hedging or power trading activities that require Bonneville to provide collateral through the posting of margin payments to secure its related power trading contract obligations. Bonneville may begin entering into exchange-traded, power-market-related financial transactions that would require that

Bonneville post margin to cover their mark-to-market value. Margin requirements could affect Bonneville's cash flows, especially if large margin payments are required. If a party does not meet margin calls, its related agreements are subject to immediate termination and the net mark-to-market value of the related agreements may become immediately due and payable.

Historical Federal System Financial Data

Federal System historical financial data for Fiscal Years 2007 through 2009 are hereinafter set forth in the "Federal System Statement of Revenues and Expenses (unaudited)." Such data have been derived from the annual audited financial statements of the Federal System and differ therefrom in some respects in the categorization of certain costs. The audited Financial Statements of the Federal System (prepared in accordance with generally accepted accounting principles ("GAAP") and provided as Appendix B-1 to the Official Statement) include accounts of Bonneville as well as those of the generating facilities that are located in the Region and owned by the Corps and Reclamation and for which Bonneville is the power marketing agency.

The Federal System unaudited quarterly financial report for the three months ended December 31, 2009 is included as Appendix B-2. For a discussion of the quarterly financial report for the three months ended December 31, 2009, see "—Management Discussion of Unaudited Results for the Three Months Ended December 31, 2009."

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

Fiscal year ending September 30,	2009	2008	2007
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Northwest Publicly-owned utilities [1]	$ 1,673,237	$ 1,504,637	$ 1,836,731
Direct Service Industrial Customers	0	405	0
Northwest Investor-Owned Utilities	143,604	214,153	281,362
Sales outside the Northwest Region [2]	273,545	603,891	460,656
Book-outs [3]	(36,814)	(109,704)	(94,705)
Total Sales of Electric Power	2,053,572	2,213,382	2,484,044
Transmission [4]	713,907	721,513	689,287
Fish Credits and other revenues [5]	102,805	101,723	95,309
Total Operating Revenues	2,870,284	3,036,618	3,268,640
Operating Expenses:			
Bonneville O&M [6]	794,277	740,871	679,711
Purchased Power [3]	317,543	450,035	310,073
Corps, Reclamation and Fish & Wildlife O&M [7]	255,059	243,073	234,469
Non-Federal entities O&M — net billed [8]	278,677	231,457	271,826
Non-Federal entities O&M — non-net billed [9]	45,236	42,032	43,328
Total Operation and Maintenance	1,690,792	1,707,468	1,539,407
Net billed debt service	461,888	457,847	319,383
Non-net billed debt service	39,479	21,646	23,938
Non-Federal Projects Debt Service [10]	501,367	479,493	343,321
Federal Projects Depreciation	355,574	358,064	351,787
Residential Exchange [11]	205,172	(1,220)	340,170
Total Operating Expenses	2,752,905	2,543,805	2,574,685
Net Operating Revenues	117,379	492,813	693,955
Interest Expense:			
Appropriated Funds	253,136	262,108	279,120
Long-term debt	60,908	62,822	55,704
Capitalization Adjustment [12]	(64,905)	(64,905)	(64,905)
Allowance for funds used during construction	(30,710)	(32,057)	(33,172)
Net Interest Expense	218,429	227,968	236,747
Net Revenues/(Expenses)	$ (101,050)	$ 264,845	$ 457,208
Total Sales (unaudited) — average megawatts (Net of Residential Exchange Program)	9,230	9,283	9,374

(1) This customer group includes Preference Customers (municipalities, public utility districts and rural electric cooperatives in the Region) and Federal agencies. This amount reflects refunds to Preference Customers arising from past overpayments of Residential Exchange Program benefits to Regional IOUs. Amounts applied in Fiscal Year 2009 were $83.3.million (see note 11 below).

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

(3) Total Operating Expenses and Revenue from Electricity Sales reflect accounting guidance associated with non-trading energy activities that are "booked out" (settled other than by the physical delivery of power) and are reported on a "net" basis in both operating revenues and purchased power expense. The accounting treatment has no effect on net revenues, cash flows, or margins.

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

(5) Bonneville also receives certain revenues from sources apart from power sales and the provision of transmission services. These revenues relate primarily to fish and wildlife credits (also referred to as "4(h)(10(C) credits") Bonneville receives to its United States Treasury repayment obligation. Such credits are provided on the basis of estimates and forecasts and later are adjusted when actual data are available. The amount of such credits was about $66.1 million, $100.4 million, and $99.5 million in Fiscal Years 2007, 2008 and 2009, respectively. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville." In addition, under Accounting Standards Codification ("ASC") 815 (formerly Financial Accounting Standards Board Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities"), Bonneville reported unrealized mark-to-market losses of $6.5 million, $30.6 million, and $34.7 million in Fiscal Years 2007, 2008, and 2009 respectively. ASC 815 requires (i) that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and (ii) that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. It is Bonneville's policy to document and apply as appropriate the normal purchase and normal sales exception under ASC 815. 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 ASC 815. These transactions are not required to be recorded at fair value in the financial statements. For all other derivative transactions Bonneville applies fair value accounting and records the amounts in the current period Statement of Revenues and Expenses. Bonneville does not apply hedge accounting.

(6) Bonneville operations and maintenance expenses include the costs of the Federal Transmission System, operation and maintenance program, energy resources, power marketing, and fish and wildlife programs.

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

(8) The Non-Federal entities O&M – net billed expense includes the operation and maintenance costs for generating facilities, the generating capability or output of which Bonneville has agreed to purchase under net billing agreements, which are capitalized contracts that cover the costs of certain generating resources, including Energy Northwest's Project 1, Project 3, and Columbia Generating Station, and Eugene Water and Electric Board's ("EWEB") 30 percent ownership share of the Trojan Nuclear Project.

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

(10) Non-Federal Projects Debt Service includes payments by Bonneville for all or a part of the generating capability of, and the related debt service, including interest, for four nuclear power generating projects (three of which have been terminated). They are Energy Northwest's Project 1, Project 3, and the Columbia Generating Station, and EWEB's 30 percent ownership share of the Trojan Nuclear Project. The remaining principal amount of Bonneville-backed bonds issued by EWEB for the Trojan Nuclear Project were paid in full at maturity on September 1, 2008.

(11) See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services" and "—Residential Exchange Program" and see "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results." Bonneville's payments to Regional IOUs with respect to the Residential Exchange Program for the period July 1, 2001 through September 30, 2011 were originally established under Residential Exchange Program Settlement Agreements, as thereafter amended and supplemented. Bonneville suspended scheduled payments under the settlement agreements when they were invalidated by the Ninth Circuit Court in May 2007. In Fiscal Year 2008, Bonneville filed supplemental proposed rates and related documents ("2009 Supplemental Power Rate Proposal") with FERC to address the ruling. Under and in connection with that filing, Bonneville proposed to recover from Regional IOUs the overpayments Bonneville made to them under the invalidated Residential Exchange Program Settlement Agreements. Bonneville also proposed to transfer these "Look-back Amounts" to Preference Customers. Such Look-back Amounts are being collected from identified Regional IOUs through credits to Residential Exchange Program benefits otherwise payable by Bonneville to the Regional IOUs and are being returned to the Preference Customers over time. For each succeeding power rate proposal and under certain accompanying documentation, Bonneville will designate the amount to be recovered from the Regional IOUs and returned to each qualifying Preference Customer. The transferred amounts to Preference Customers do not reduce power rates for Preference Customers, but are reflected as credits to amounts that qualifying Preference Customers would otherwise pay to Bonneville for electric power and related services. (In some instances the transfers to Preference Customers will be effected by cash payments). Bonneville

recognizes a refund and reduces expense in each year Look-back Amounts are recovered and transferred and will do so until all overpayments are recovered. These transactions with respect to the Look-back Amounts are net operating revenue neutral as the same amount reduces both revenue and expense. The Look-back Amount applied in Fiscal Year 2009 was $83.3 million. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program." The aggregate amount of suspended payments under the Residential Exchange Program Settlement Agreements in Fiscal Year 2007 was $168 million. In Fiscal Year 2008, the amounts for prior years were adjusted through a rate case process and the accumulated effects of those adjustments and the current year expense are shown as the $1.2 million credit. See "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results—Fiscal Year 2008."

(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 2009

For Fiscal Year 2009, Power Services and Transmission Services consolidated gross revenues decreased $228 million, or eight percent, from the prior year. Power Services gross revenues decreased $233 million, or 10 percent. The change was primarily due to several key factors. Revenues were down $490 million from Fiscal Year 2008 due to lower Federal System hydro-generation caused by less river runoff and reduced Columbia Generating Station output due to planned and unplanned outages. A metric Bonneville uses to measure year-to-year changes in river runoff is million acre-feet ("maf") measured at The Dalles Dam. This amount was 117 maf and 126 maf for Fiscal Years 2009 and 2008, respectively, compared to the historical average of 133 maf. In addition, the downturn in the economy resulted in lower demand and prices for seasonal surplus (secondary) energy and lower demand for firm power for Regional loads.

To address the Ninth Circuit Court's ruling that set aside the Residential Exchange Program Settlement Agreements between Bonneville and each of the Regional IOUs, Bonneville supplemented its then-extant power rate proposal to begin correcting for the overpayments of Residential Exchange benefits and for the corresponding recovery of such costs in power rates charged to Preference Customers. Under this supplemental power rate proceeding and proposal, Bonneville's power rate levels for Fiscal Year 2009 were changed during the 2007-2009 Power Rate Period, resulting in PF Rates other than for Slice Customers being about one percent lower than for the same service in Fiscal Year 2008. The decrease in revenue from lower non-Slice PF Rates was offset, however, by the effects of the Residential Exchange Program refunds by which Bonneville began recovering the past overpayments of Residential Exchange benefits to Regional IOUs. Refunds under this recovery program are obtained by Bonneville through payment offsets to Residential Exchange benefits paid to the Regional IOUs. These refunds were approximately $83 million and $341 million in Fiscal Years 2009 and 2008, respectively. The large amount in Fiscal Year 2008 arose because Bonneville had temporarily withheld all payments with respect to the Residential Exchange pending the development of its proposal to address the court ruling and correct for the past overpayments of Residential Exchange benefits. In view of this suspension Bonneville accrued related cash balances in the Bonneville Fund. As and after Bonneville developed a proposal for correcting the overpayments, Bonneville made lump sum payments to both the Preference Customers and the Regional IOUs. See "—Fiscal Year 2008."

Transmission Services sales decreased $7.6 million, or one percent.

The increase in the unrealized loss of Bonneville's derivative instruments of $4 million, or 13 percent, was due primarily to the following key factors: decrease in the 10 and 15 year forward Libor swap curves and decrease in the forward power price curve and its effect on Bonneville's commodity derivative instruments.

Operating expense increased $209 million, or eight percent, from Fiscal Year 2008. Operations and maintenance increased $322 million, or 26 percent, from the prior fiscal year, due primarily to: $206 million associated with correcting past overpayments of Residential Exchange Program benefits; $51 million increase in scheduled maintenance and biennial refueling; and $29 million increase in fish and wildlife expense. Purchased power expense decreased $132 million, or 29 percent, due to lower market prices and volume of purchases, offset by an increase in purchased power due to the unplanned outage at Columbia Generating Station. Nonfederal projects debt service increased $22 million, or five percent, due to increased Libor interest expense and repayment of Columbia Generating Station debt, partially offset by lower repayment of Energy Northwest's Project 1 and Project 3 debt.

Net interest expense decreased $10 million, or four percent, compared to Fiscal Year 2008. The primary reason for the decreased interest expense was a reduction of the weighted-average interest rates on outstanding appropriations owed and bonds issued to the United States Treasury.

Net revenues were negative $101 million in Fiscal Year 2009, a decrease of $366 million from positive net revenues of $265 million in Fiscal Year 2008, primarily as a result of the factors discussed above. With respect to “Modified net revenues” (*i.e.*, net revenues after adjusting for the effects of the unrealized fair value of derivative instruments and nonfederal debt management actions that differ from rate case assumptions), modified net revenues were negative $187 million compared to $157 million in positive modified net revenues in Fiscal Year 2008, representing a decline of $344 million. Bonneville believes that modified net revenues are a better reflection of Bonneville’s financial results than standard accounting determinations of net revenues.

Fiscal Year 2008

For Fiscal Year 2008, Federal System total operating revenues were $3.037 billion, a decrease of $232 million from Fiscal Year 2007. Power Services and Transmission Services combined gross sales decreased $224 million, or 7 percent, from the comparable period a year earlier. Power Services gross sales revenues decreased $256 million or 10 percent. The change was primarily due to the following key factors: In Fiscal Year 2008 there was a downward adjustment of $341 million due to the impacts of the rate proceeding on the Residential Exchange Program; there was a slight increase in long-term contractual obligations and sales under existing contracts resulting in a $24 million increase in revenues from firm power sales; due to a below-average water year and a delayed but rapid runoff, Bonneville purchased power in the spring to meet projected river operation needs and once these needs were met, remaining power was sold at a slightly higher price, resulting in a $61 million increase in surplus sales.

The $341 million downward adjustment in revenues reflects a $257 million refund of amounts to be returned to Preference Customers for over-collections from them by Bonneville in Fiscal Years 2007 and 2008 with respect to the Residential Exchange, plus the effects of the $67 million downward adjustment in revenues from Preference Customers as a result of the recoupment from Regional IOUs of a portion of overpayments made by Bonneville under the Residential Exchange Program Settlement Agreements in the fiscal years prior to Fiscal Year 2007 (Look-back Amounts), and a downward adjustment in revenues from Preference Customers flowing from $17 million collected in rates in Fiscal Year 2003 for certain deferred Residential Exchange-related benefits to Regional IOUs.

Transmission Services gross sales increased $32 million, or 5 percent. The change was primarily due to the following key factors: network and intertie transmission sales and their associated ancillary services increased. Significant reasons for the increased revenues were the result of increased Point-to-Point and Intertie long-term and Point-to-Point short-term sales. There was also a slight increase in Point-to-Point and Intertie long-term rates from last fiscal year. The increase in revenues was offset by ancillary services primarily by elimination of revenues from customers using the ancillary service product “Reactive Supply and Voltage from Generation.” This was a result of an agreement by Bonneville during the Transmission Services rate proceeding for rates and ancillary services for the two fiscal years beginning October 1, 2008.

The change in the unrealized fair value of Bonneville’s derivative portfolio of $24 million was due to fluctuations in the forward price curves, physical delivery and a change in the overall portfolio mix. The change is primarily the result of a $17 million decrease in the value of swap agreements due to a decrease in the LIBOR index rate. Credits under Northwest Power Act section 4(h)(10)(C) increased $34 million, or 52 percent, in Fiscal Year 2008 when compared to the prior fiscal year as stream flows declined and market prices for purchased power increased. For a description of section 4(h)(10)(C) and related credits, see “POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville’s Power Services—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville.”

In total operating expenses decreased $31 million, or one percent, from Fiscal Year 2007. The decline was the result of several factors. Residential Exchange expense decreased $341 million (arising from Bonneville’s proposed downward re-determination of such benefit levels) as previously discussed above with respect to the decrease in Preference Customer revenues. To a large extent the decrease was offset by increases for purchased power and nonfederal projects debt service expense. Purchased power increased $140 million, or 45 percent, due to a combination of higher prices and increased purchases as a consequence of delayed runoff and the associated reduction in Federal System hydroelectric generation. Nonfederal projects debt service increased $136 million, or 40 percent, due to scheduled amortization of Energy Northwest bonds. The lower amortization for the prior period was the result of extension of nonfederal debt and early repayment of federal debt within Bonneville’s total debt portfolio under the Debt Optimization Program. The overall objective of these debt management actions has been to achieve an optimal total debt portfolio. The portfolio includes federal appropriations, United States Treasury borrowings and nonfederal projects debt.

Net interest expense declined $9 million, or four percent. The primary reason for the decreased interest expense between years was a reduction of outstanding appropriated funds owed the United States Treasury. Interest on bonds issued to the United States Treasury declined $4 million as interest income increased $6 million due to earnings on higher cash balances in the Bonneville Fund.

Net revenues were $265 million in Fiscal Year 2008, a decrease of $192 million, or 42 percent, from Fiscal Year 2007 as a result of the factors discussed above. However, modified net revenues (*i.e.*, net revenues after adjusting for the effects of the unrealized fair value of derivative instruments and nonfederal debt management actions that differ from rate case assumptions) were $157 million compared to $217 million in Fiscal Year 2007, representing a 28 percent decline. Bonneville believes that modified net revenues are a better reflection of Bonneville's financial results than standard accounting determinations of net revenues.

Fiscal Year 2007

For Fiscal Year 2007, Federal System total operating revenues were $3.269 billion, a decrease of $151 million from Fiscal Year 2006. Revenues from electricity and transmission sales for Fiscal Year 2007 were down $234 million, or 7 percent, from Fiscal Year 2006. Power revenues decreased $281 million, or 10 percent. Reduced stream flows and the bi-annual refueling of Columbia Generating Station nuclear power plant drove down generation. In addition, Bonneville had reduced power purchases. Therefore, less secondary energy was available for sale in Fiscal Year 2007. During Fiscal Year 2007, Bonneville provided monetary benefits rather than power to the DSIs. In contrast to prior years when Bonneville made certain power sales to certain Regional IOUs in connection with their Residential Exchange Program Settlement Agreements, in Fiscal Year 2007 Bonneville provided only monetary benefits rather than power in connection with the Residential Exchange Program. Transmission revenues increased $47 million, or 8 percent from Fiscal Year 2006 mainly due to increased sales under long-term point-to-point network and short-term contracts for transmission on the Southern Intertie. Load-based transmission sales to Preference Customers also increased due to greater than anticipated load growth. A small part of the increase in transmission service revenue is associated with revenues from Ancillary Services, which vary with the sale of transmission and are needed to ensure efficient and reliable service.

In total, operating expenses increased $28 million, or one percent, from Fiscal Year 2006. Purchased power decreased $225 million, or 42 percent, compared to Fiscal Year 2006. Purchased power decreased because a number of power purchase contracts entered into in the prior power rate period to meet greater than anticipated load expired at or before the end of Fiscal Year 2006. This reduction was offset to a degree by Residential Exchange benefits payments which increased $184 million, or 118 percent, from the prior fiscal year. Through Fiscal Year 2006, Residential Exchange Program benefits to Regional IOUs were provided through arrangements to purchase back certain previous power sales commitments to the Regional IOUs. The buy backs were made by Bonneville to meet other firm power sales obligations and the related payments by Bonneville were therefore included in Federal System financial statements as purchased power expense. Beginning with Fiscal Year 2007, all Residential Exchange Program benefits amounts were provided entirely through monetary payments pursuant to the Residential Exchange Program Settlement Agreements. (The Residential Exchange Program Settlement Agreements were set aside upon court review in May 2007 and Bonneville suspended related payments immediately thereafter). Net billed non-Federal entities O&M and net billed debt service increased $45 million and $4 million, respectively, due to bi-annual refueling of Columbia Generating Station and higher debt service expense for Energy Northwest.

Net interest expense for Fiscal Year 2007 decreased $25 million, or nine percent, compared to Fiscal Year 2006. Interest expense on appropriated funds increased $9 million. Interest on bonds issued to the United States Treasury declined $5 million as interest income increased $24 million with higher cash balances. Allowance for funds used during construction increased $5 million as higher construction work in progress balances at Corps and Reclamation facilities of the Federal System offset to a degree by a decline resulting from the completion of a large transmission project, the Schultz Wautoma transmission line, in Fiscal Year 2006.

Net revenues were $457 million in Fiscal Year 2007, a decrease of $154 million, or 25 percent, from Fiscal Year 2006 as a result of the factors discussed above. However, modified net revenues (*i.e.*, net revenues after adjusting for the effects of the unrealized fair value of derivative instruments and nonfederal debt management actions that differ from rate case assumptions) were $217 million compared to $445 million in Fiscal Year 2006, representing a 51 percent decline.

Statement of Non-Federal Project Debt Service Coverage

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

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

Fiscal Years ending September 30,	**2009**	**2008**	**2007**
Total Operating Revenues	$2,870,284	$3,036,618	$3,268,640
Less: Operating Expense(1)	1,640,904	1,463,174	1,645,108
Net Funds Available for Non-Federal Project Debt Service	1,229,380	1,573,444	1,623,532
Less:			
Non-Federal Project Debt Service(2)	501,367	479,493	335,289
Lease Financing Program(3)	17,369	11,063	8,032
Revenue Available for Treasury	710,644	1,082,888	1,280,211
Amount Allocated for Payment to Treasury(8):			
Corps and Reclamation O&M(4)	255,059	243,073	234,469
Net Interest Expense(5)	218,429	227,968	236,747
Lease Financing Program(3)	(17,369)	(11,063)	0
Capitalization Adjustment(6)	64,905	64,905	64,905
Allowance for Funds Used During Construction(5) (7)	12,093	13,596	8,165
Amortization of Principal	432,019	555,269	618,400
Total Amount Allocated for Payment to Treasury(8)	965,136	1,093,748	1,162,686
Revenues Available for Other Purposes(9)	(254,492)	(10,860)	117,525
Non-Federal Project Debt Service Coverage Ratio(10)	2.4	3.2	4.7
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio(11)	1.3	1.6	1.6

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

(2) Includes debt service for generating resources acquired by Bonneville under net billing agreements or other capitalized contracts. Non-net billed debt service amounted to $23.9 million, $21.6 million, and 39.5 million for Fiscal Years 2007, 2008 and 2009, respectively.

(3) Debt service payments, including interest, by Bonneville with respect to certain transmission facilities owned by NIFC, NIFC II, NIFC III, and NIFC IV, leased to Bonneville on a capitalized basis. To reconcile Net Interest Expense as reported in the audited financial statements of the Federal System (included as Appendix B-1 to the Official Statement) the Lease Financing Program as shown here is a reduction of Revenue Available for United States Treasury.

(4) Amounts shown are calculated on an accrual basis and include direct operations and maintenance payments to the Corps, Reclamation and Fish & Wildlife for Fiscal Years 2007, 2008 and 2009. See "—Direct Funding of Federal System Operations and Maintenance Expense."

(5) Beginning with Fiscal Year 2008, Lease Financing Program is included in Net Interest Expense as reported in the audited financial statements of the Federal System. Amounts shown are calculated on an accrual basis.

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

(7) The Allowance for Funds Used During Construction is Bonneville's portion of the interest component on the Federal investment during the construction period.

(8) In contrast to the Amount Allocated for Payment to United States Treasury, Bonneville's payments to the United States Treasury in Fiscal Years 2007, 2008 and 2009 were $1.045 billion and $963 million, and $845 million, respectively, and include the amounts for each such year for direct funding for the Corps, Reclamation and Fish & Wildlife as portrayed under "Corps and Reclamation O&M." See "—Direct Funding of Federal System Operations and Maintenance Expense."

(9) Revenues Available for Other Purposes approximates the change in reserves from year to year. Fiscal year end reserves have been as low as $188 million at the end of Fiscal Year 2002 (not depicted).

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

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

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

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

Management Discussion of Unaudited Results for the Three Months Ended December 31, 2009

For the three months in the fiscal year-to-date ended December 31, 2009 ("Fiscal Year 2010 First Quarter"), modified net revenues were $70 million higher when compared to the comparable period a year earlier. The primary reason for the change is that Power Services sales increased $59 million, or 11 percent, because of higher power rates that went into effect (on a provisional basis pending final FERC review) on October 1, 2009, partially offset by lower revenues from secondary sales. In aggregate, Bonneville's total sales revenues increased $74 million, or about 10 percent, when compared to the first quarter of the prior fiscal year, including an increase in Transmission Services sales of $15 million, or nine percent. The major reason for the Transmission Services revenue increase was increased revenue from the sale of certain ancillary services, including wind balancing services, and an increase in sales of Point-to-Point service.

Operations and maintenance increased $3 million, or one percent, for Fiscal Year 2010 First Quarter when compared to the first quarter a year earlier. Purchased power decreased $34 million, or 27 percent, due to lower market prices. Nonfederal projects debt service increased $27 million, or 22 percent, primarily due to increased amortization for Columbia Generating Station.

The unrealized loss on derivative instruments decreased by $31 million for Fiscal Year 2010 First Quarter when compared to the comparable period a year earlier. The change was primarily due to improved mark-to-market valuation on the Libor Interest Rate Swaps as a result of an increase in the 10 and 15 year yield curves. See "BONNEVILLE FINANCIAL OPERATIONS—Position Management and Derivative Instrument Activities and Policies."

For further information regarding Fiscal Year 2010 First Quarter unaudited results, see Appendix B-2 entitled "FEDERAL SYSTEM UNAUDITED REPORT FOR THE THREE MONTHS ENDED DECEMBER 31, 2009." For information regarding Bonneville's Fiscal Year 2010 financial expectations, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Fiscal Year 2010 Expectations."

BONNEVILLE LITIGATION

ESA Litigation

Columbia River

In a lawsuit filed May 4, 2001, in the United States District Court for the District of Oregon ("District Court"), the National Wildlife Federation and other plaintiffs asked the court: (1) to declare that the 2000 FCRPS Biological Opinion and incidental take statement were arbitrary and capricious, an abuse of discretion, and otherwise not in accordance with law, and (2) to order NOAA Fisheries to reinitiate consultation with the action agencies responsible for operation of the Federal System hydroelectric projects—the Corps, Reclamation, and Bonneville (collectively, the "Action Agencies")—and to prepare a new biological opinion.

In early May 2003, the District Court ruled that the 2000 Biological Opinion was inadequate because it relied on offsite mitigation measures that were "not reasonably certain to occur" and because the biological opinion used an "action area" (the geographically delineated area comprising where the dam's operation directly or indirectly affect ESA listed species) that was too small. In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court.

On November 30, 2004, NOAA Fisheries finalized a subsequent biological opinion (the "2004 Biological Opinion") to replace the 2000 Biological Opinion and address the deficiencies identified by the District Court. . See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—Columbia River System Biological Opinions." Plaintiffs filed a complaint against NOAA Fisheries and subsequently filed another complaint against the Corps and Reclamation with the District Court alleging that the 2004 Biological Opinion and the Corps' and Reclamation's decisions to operate consistent with the Biological Opinion violated certain provisions of the ESA and APA. On May 26, 2005, the court issued an opinion identifying several deficiencies in the 2004 Biological Opinion. The court's ruling was finalized in October 2005, and the court issued an order remanding the matter to the Federal agencies to correct identified deficiencies. Additionally, in the court's October remand order, the Federal agencies were ordered to undertake collaboration with the sovereign parties to the litigation (states and tribes) to address key issues in a new biological opinion. The Federal Government and the State of Idaho appealed the order to the Ninth Circuit Court, which ultimately denied the appeals and upheld the order.

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

On March 6, 2009, a status hearing was held in the District Court on cross motions for summary judgment. On April 2, 2009, an in-chambers meeting was convened by the presiding District Court judge with all parties to the litigation. At the suggestion of the court, the administration of President Barack Obama performed a review of the 2008 Columbia River System Biological Opinion. On May 18, 2009, the court issued a letter to the Federal agencies posing questions and issues it suggested be addressed in the administration's review of the 2008 Columbia River System Biological Opinion. On September 15, 2009, the Federal agencies filed a Management Plan with the court. In the Management Plan, the Federal agencies outlined and the administration approved a more detailed and aggressive plan for implementing the adaptive management provisions of the 2008 Columbia River System Biological Opinion. The administration's position, as expressed in the court filing, is that the 2008 Columbia River System Biological Opinion as implemented through the Management Plan, is biologically and legally sound and based on the best available scientific information. On February 19, 2010, the District Court judge entered a voluntary remand order that gives the Federal agencies three months (until May 20, 2010) to consider, among other things, integrating the Management Plan into the administrative record so that it may be taken into account in the court's evaluation of the 2008 Columbia River System Biological Opinion. The Federal agencies have begun the remand process. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act" and "—Columbia River System Biological Opinions."

There has also been related litigation in which plaintiffs have sought injunctive relief on certain Federal System dam operations that were included in the original 2004 Biological Opinion. The District Court ordered additional spill to that provided in the 2004 Biological Opinion which was requested by plaintiffs and intended to aid downstream migration of juvenile salmon and steelhead species in the summer of 2005. When water is spilled, it is diverted through dam spillways and does not run through hydroelectric turbines, thereby reducing power generation. Bonneville estimated that the court-ordered spill resulted in about $75 million in foregone power revenues in Fiscal Year 2005 when compared to the revenues that would have accrued had summer spill occurred as required under the 2004 Biological Opinion.

For 2006 river operations, the Federal Government proposed (and the court approved) a spill program that was similar although not identical to the spill program the court had ordered in the summer of 2005. Bonneville estimates that the 2006 spill order, which included spring as well as summer spill, resulted in somewhat greater hydroelectric generation than would have occurred under the 2005 summer spill program. For 2007, 2008 and 2009 hydro-operations, the Federal agencies proposed a spill program similar to the 2006 spill program and obtained court approvals. In view of the current expectations of low water conditions for the remainder of Operating Year 2010, hydro-operations have not been resolved for spring and summer of 2010.

DSI Service ROD Litigation

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

On September 28, 2005, Alcoa, a Bonneville direct service industrial customer, filed a petition for review in the Ninth Circuit Court challenging the DSI ROD. On the same day, the Pacific Northwest Generating Cooperative ("PNGC"), a consortium of Bonneville Preference Customers, filed a separate petition for review. Alcoa's legal theory is that Bonneville has a perpetual obligation to serve the DSIs with actual, physical power at Bonneville's lowest cost-based rates. Conversely, PNGC contends that Bonneville lacks statutory authority to provide service benefits to the DSIs. In August 2006, Alcoa and PNGC filed additional petitions related to Bonneville's decisions for service to the DSIs in Fiscal Years 2007-2011. These additional petitions challenge Bonneville's Supplement to the DSI ROD, issued on May 31, 2006, and the power sales contracts executed by and between Bonneville and the aluminum company DSIs in June 2006. Additionally, on October 6, 2006, Alcoa filed a petition challenging Bonneville's execution of a power sales contract to serve Port Townsend, a small non-aluminum DSI customer. Finally, in November 2006, the Industrial Customers of Northwest Utilities filed a petition that likewise challenges Bonneville's Port Townsend power sales contract. All of the foregoing petitions have been consolidated, and oral arguments and briefing have been completed.

On December 17, 2008, the Ninth Circuit Court affirmed Bonneville's long-held position that Bonneville has the statutory authority, but not the obligation, to sell power to the DSIs after Fiscal Year 2001. However, the court determined that if Bonneville elects to sell firm power to the DSIs, whether pursuant to section 5(d) or 5(f) of the Northwest Power Act, Bonneville must first offer such power at the Industrial Firm Power ("IP") Rate. Only after the DSIs have refused to purchase power at the IP Rate may Bonneville offer them power under Bonneville's FPS rate schedule, which is a rate schedule that Bonneville includes in its wholesale power rate proposals which rate schedule provides Bonneville substantial flexibility in pricing sales of power. (Bonneville sells much of its secondary energy at market prices under the FPS rate schedule, but sales under the FPS schedule are not limited to market price sales.) The court also agreed with Bonneville that it has the authority to monetize its DSI contracts, so long as doing so is otherwise consistent with Bonneville's statutory obligations.

The Ninth Circuit Court held that Bonneville impermissibly agreed to forgo revenue by monetizing the difference between a rate for DSIs below the rate authorized by statute (the "IP Rate") and prices available on the open market. The foregone revenue resulted in higher rates for all other customers, creating an impermissible subsidy and making it inconsistent with Bonneville's obligation to maintain the lowest possible rates consistent with sound business principles. The Court remanded the case back to Bonneville to determine the applicability of the agreements' severability and damage waiver provisions in light of the Court's holdings.

For Fiscal Year 2009 only, Bonneville and Alcoa agreed to contract amendments to conform the agreement to the court's ruling. Bonneville believed that under the amendment, the monetized power benefits it provided Alcoa for the remainder of Fiscal Year 2009 were likely be the same as expected under the original agreement. The amendment assured that in no event would the monetized power benefit be greater than originally agreed to.

Bonneville and CFAC have also executed certain contract amendments to recalculate payments for the months of December 2008, and January and February 2009, to be consistent with the court's December 2008 ruling. The amendments are substantially similar to the amendments entered into with Alcoa in January 2009, and provide for Bonneville to monetize a power sale to CFAC in a manner consistent with the court's December 2008 ruling.

In January 2009, PNGC and the Public Power Council ("PPC"), a coalition of Preference Customers, filed litigation in the Ninth Circuit Court challenging Bonneville's agreement to amend the Alcoa agreement. PNGC and PPC requested that the new petitions be heard on an expedited basis and that the panel which decided PNGC also preside over the new petitions. The Court granted these requests and heard oral argument in the case on July 7, 2009. On August 28, 2009, the Court ruled that Bonneville's amended agreement with Alcoa was inconsistent with sound business principles and therefore unlawful. Alcoa and Bonneville have filed petitions for rehearing, which are currently pending.

It is uncertain at this time whether Bonneville will take retroactive action regarding payments made to Alcoa or CFAC during Fiscal Years 2007 and 2008, which payments may have exceeded the amount that would have been paid if the contract had included terms consistent with the above referenced court opinion.

In November 2009, Bonneville entered into a 14-month contract with Port Townsend for sales through December 31, 2010. In December 2009, the parties agreed to extend the term of this contract by an additional five months, through May 2011.

In December 2009, Bonneville entered into a long-term contract with Alcoa commencing December 22, 2009. Under the contract, Bonneville will make available to Alcoa up to 320 average megawatts each hour for a period of up to approximately seven years, at the IP Rate. The term of the contract is divided into two main periods, the Initial Period and the Second Period, with the Initial Period encompassing the approximately 17-month period December 22, 2009 through May 26, 2011, and the Second Period encompassing the five-year period following expiration of the Initial Period. In both new DSI contracts, Bonneville has included terms that address the court's concerns as stated in the recent ruling. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Loads and Related Contracts and Power Rates through Fiscal Year 2011—Loads and Resource Expectations in Operating Years 2010 and 2011—DSI Loads."

On January 22, 2010, Alcoa filed a petition for review in the Ninth Circuit Court challenging Bonneville's long-term contract with Alcoa, dated December 21, 2009, and Bonneville's Record of Decision in support of the contract. Although the petition does not specifically state the nature of the claims that Alcoa intends to raise, Bonneville believes that Alcoa is challenging Bonneville's interpretation of the recent ruling and the terms of the new contract. Avista Corp. ("Avista"), Idaho Power Company, Oregon Public Utilities Commission, PacifiCorp, PNGC, and PPC have intervened to challenge the Alcoa contract.

On February 11, 2010, the Industrial Customers of Northwest Utilities ("ICNU") filed a petition for review in the Ninth Circuit Court challenging Bonneville's 14-month contract with Port Townsend, extension of the Block contract with Port Townsend, and the Records of Decision in support of the contracts. Although the petition does not specifically state the nature of the claims that ICNU intends to raise, Bonneville believes that ICNU is challenging Bonneville's interpretation of the recent ruling and the terms of the new contract and contract extension.

Long-Term Regional Dialogue Contracts, Policies and Records of Decision

On October 16, 2007, Alcoa, Inc., and PPC each filed a petition for review under the Northwest Power Act challenging Bonneville's Long-Term Regional Dialogue Final Policy, and Bonneville's Long-Term Regional Dialogue Record of Decision ("July 2007-ROD"), both of which were issued on July 19, 2007. The Long-Term Regional Dialogue Final Policy addresses Bonneville's role in power marketing for the period after Fiscal Year 2011, and lays the foundation for Bonneville to move forward to develop power sales contracts, products, services and rates that will be established for the period of time covered by the policy. Bonneville's July 2007-ROD explains Bonneville's rationale for its determinations in the Regional Dialogue Policy. On February 18, 2009, the parties filed a joint motion to vacate the briefing schedule and stay proceedings. The parties advised the court that they will file an additional motion to consolidate these cases with a series of new petitions for review that have been filed, described immediately below. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE— Power Sales and Related Arrangements in the Period after Fiscal Year 2011."

On January 27, 2009, Avista, a Regional IOU, filed a petition for review in the Ninth Circuit Court challenging Bonneville's Long-Term Regional Dialogue Contract Record of Decision dated October 31, 2008 ("October 2008-ROD"). Numerous other petitions for review were filed shortly thereafter challenging the October 2008-ROD and/or certain Regional Dialogue power sale contracts that were executed on or around December 1, 2008. On February 27, 2009, Bonneville filed a motion to consolidate these cases as well as a motion to vacate the briefing schedules that were automatically established upon the filing of the petitions for review. The cases were consolidated and briefing is in progress. Opening briefs were filed by Grays Harbor Public Utility District ("Grays Harbor") and by the Pacific Northwest Investor Owned Utilities ("IOUs").

In its opening brief, Grays Harbor argued that it was forced to sign its Regional Dialogue contract and that it did not agree with certain provisions in the contract concerning billing credits and residential exchange benefits. The IOUs, in their joint opening brief, argued that, as PF Exchange Rate customers of Bonneville, they were entitled to an equitable share of the value of Environmental Attributes that were conveyed to preference customers under their Regional Dialogue contracts. Bonneville fully responded to the arguments of Grays Harbor and the IOUs in Bonneville's Answering Brief and explained why the petitions should be denied. Respondent-intervenor briefs in support of Bonneville were filed by various Bonneville preference customers. The Petitioners' reply briefs were filed on January 15, 2010.

On December 17, 2008, Public Utility District No. 1 of Clark County ("Clark County") filed a petition for review in the Ninth Circuit Court challenging certain provisions of its Regional Dialogue power sales contract, executed on December 1, 2008. Clark County alleges that these provisions require Clark County to waive its statutory rights to full participation in the residential exchange and billing credits programs established under the Northwest Power Act. Neither Bonneville nor Clark County moved to consolidate this case with the other cases challenging the Regional Dialogue Contract Policy Record of Decision, or Regional Dialogue power sales contracts. The parties entered into settlement discussions which resulted in a joint motion for voluntary dismissal. The court granted the motion and the case was dismissed on November 9, 2009.

On January 27, 2009, ICNU filed a petition challenging Bonneville's Tiered Rates Methodology Record of Decision ("Tiered Rates ROD") and Bonneville's Tiered Rates Methodology, both issued November 10, 2008. Similar petitions for review were filed on February 5, 2009, by Georgia-Pacific, LLC ("GP") and Clatskanie People Utility District ("Clatskanie") challenging the same Tiered Rates ROD and the Tiered Rates Methodology. The three petitions have been consolidated and briefing is almost complete.

All three petitioners challenge Bonneville's determination in the Tiered Rates Methodology regarding Bonneville's treatment of "contracted for or committed to" loads, a term of art under section 3(13)(A) of the Northwest Power Act. These parties allege that Bonneville's decision to serve certain "contracted for or committed to" loads at the Tier 2 PF Rate rather than at the Tier 1 PF Rate violates provisions of the Northwest Power Act and is arbitrary and capricious under the Administrative Procedures Act. In addition, petitioner GP alleges that Bonneville's decision constitutes a "taking" of its property under the Fifth Amendment of the U.S. Constitution for which "just compensation" is due. In response, Bonneville has argued that the petitions should be dismissed because the Court lacks subject matter jurisdiction and, if the petitions are not dismissed, then they should be denied on the merits. No date has yet been set for oral argument.

2002 Final Power Rates Challenge

On May 3, 2007, the Ninth Circuit Court issued (i) an opinion with respect to petitions for review challenging Bonneville's 2000 Residential Exchange Program Settlement Agreements ("PGE Proceeding") (discussed in the immediately following section) and (ii) an opinion with respect to petitions for review challenging certain aspects of Bonneville's final power rates for Fiscal Years 2002 through 2006 (*Golden Northwest Aluminum, Inc. v. Bonneville*) (the "Golden Northwest Proceeding"). In the Golden Northwest Proceeding, the court upheld Bonneville's authority to acquire resources to replace reductions in the capability of Bonneville's Federal Base System ("FBS") resources and the allocation of expanded FBS costs to Preference Customers. The court also held that Bonneville had improperly allocated costs of Bonneville's 2000 Residential Exchange Program Settlement Agreements to Preference Customers. Finally, the court held that Bonneville should have considered new information when developing its forecast of fish and wildlife costs to consider whether higher fish and wildlife costs should have been assumed in developing rates. The court remanded to Bonneville to "set rates in accordance" with its opinion.

Bonneville did not file a petition for rehearing; however Regional IOUs (respondent-intervenors in the PGE Proceeding) filed petitions for rehearing and rehearing *en banc* on July 18, 2007. The court later denied the petitions for rehearing. Bonneville addressed the implications of the Ninth Circuit Court's opinions in administrative proceedings, including the 2009 Supplemental Power Rate Proposal. Bonneville issued its final record of decision for that proceeding in September 2008 and filed its proposal with FERC on September 29, 2008. FERC granted final confirmation and approval of Bonneville's 2009 Supplemental Power Rates on July 16, 2009 Several parties filed petitions in the Ninth Circuit Court for review under Section 9(e) of the Northwest Power Act seeking review of Bonneville's 2009 Supplemental Power Rates and aspects of the ratemaking proceedings. In January 2010, Bonneville filed the administrative record with the Ninth Circuit Court. On February 2, 2010 certain PF Rate customers filed a motion for the Ninth Circuit Court to sever and remand an alleged ratemaking issue to Bonneville with direction to calculate and refund amounts charged by Bonneville in rates and paid by PF Rate customers for the cost of the subsidies to the DSIs found unlawful in litigation related to the past DSI service. See "—DSI Service ROD Litigation." On February 16, 2010, Bonneville, Alcoa, and Regional IOUs filed separate responses opposing the motion.

Residential Exchange Program Litigation

In Fiscal Year 2000, Bonneville prepared certain *pro forma* Residential Purchase and Sales Agreements ("2000 RPSAs") and tendered the form of such agreements to the Regional IOUs for their consideration and possible execution. The *pro forma* 2000 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 SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program." During the same time-frame, Bonneville negotiated the Residential Exchange Program Settlement Agreements with Regional IOUs, which agreements were intended to settle Bonneville's statutory Residential Exchange Program obligation under such agreements in lieu of the 2000 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 2000 RPSAs.

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

Bonneville also entered into agreements with respect to the other four Regional IOUs. Under these agreements, Bonneville intended to obtain reductions in financial payments to such Regional IOUs of about $3-$4 million in aggregate, per year.

Beginning in 2004, a number of Bonneville's customers and customer groups filed petitions with the Ninth Circuit Court seeking review of the 2000 RPSAs and the Residential Exchange Settlement Agreements and the related records of decisions prepared by Bonneville. Among those participating in the litigation were a group of DSIs, all six Regional IOUs and a number of Preference Customers and Preference Customer groups. The litigation challenging the Residential Exchange Settlement Agreements is referred to as the "PGE Proceeding." See "—2002 Final Power Rates Challenge." The petitions for review challenging certain aspects of Bonneville's final power rates for Fiscal Years 2002 through 2006 are referred to as the "Golden Northwest Proceeding."

Public Utility District No. 1 of Snohomish County, Washington ("Snohomish"), a large Preference Customer, filed an additional petition for review in the Ninth Circuit Court challenging Bonneville's Record of Decision, dated October 21, 2003, wherein Bonneville determined it would offer to settle multiple lawsuits in hopes of reaching a global settlement of many related lawsuits. The proceeding is referred to herein as the "Snohomish 2 Proceeding." The settlement offer was ultimately rejected. On October 11, 2007, the court issued a memorandum opinion dismissing the Snohomish 2 Proceeding for lack of jurisdiction.

On April 27, 2004, Snohomish filed a petition for review in the Ninth Circuit Court (the proceeding is referred to herein as the "Snohomish 3 Proceeding") related to the Snohomish 2 Proceeding. In the Snohomish 3 Proceeding, as in the Snohomish 2 Proceeding, petitioner challenged aspects of Bonneville's record of decision, dated October 21, 2003, supporting Bonneville's litigation settlement proposal, and also challenged related contracts between Bonneville and certain Regional IOUs. On October 11, 2007, the court dismissed the Snohomish 3 Proceeding for lack of jurisdiction.

Public Utility District No. 1 of Grays Harbor County, Washington, challenged Bonneville's record of decision on its "Financial Settlement Agreement And Amendment To Residential Exchange Program Settlement Agreement With PacifiCorp," and Bonneville's record of decision for its "Amended Residential Exchange Program Settlement Agreement With Puget Sound Energy." On October 11, 2007, the court issued a memorandum opinion dismissing the case as moot.

On May 3, 2007, the Ninth Circuit Court issued (i) an opinion with respect to the petitions for review in the PGE Proceeding challenging Bonneville's decision in 2000 to enter into the Residential Exchange Settlement Agreements in connection with the Residential Exchange Program, and (ii) an opinion with respect to petitions for review in the Golden Northwest Proceeding challenging certain aspects of Bonneville's final power rates for Fiscal Years 2002 through 2006. The court in the PGE Proceeding held that Bonneville failed to properly implement the Residential Exchange Program provisions of the Northwest Power Act when it entered into the Residential Exchange Settlement Agreements, and that such agreements are "inconsistent with the Northwest Power Act." The court in the Golden Northwest Proceeding held, among other things, that consistent with its holding in the PGE Proceeding, Bonneville improperly allocated to Preference Customers' rates, the costs of providing Residential Exchange Program benefits to the Regional IOUs under the Residential Exchange Program Settlement Agreements. See "—2002 Final Power Rates

Challenge." The Regional IOUs filed petitions for rehearing of the ruling in the PGE Proceeding. The motions were denied.

In 2004, three parties, including Snohomish, filed petitions for review in the Ninth Circuit challenging Bonneville's Record of Decision, dated May 25, 2004, entitled "Proposed Contracts or Amendments to Existing Contracts with the Regional Investor-Owned Utilities Regarding the Payment of Residential and Small-Farm Consumer Benefits under the Residential Exchange Program Settlement Agreements FY 2007-2011," ("Exchange Settlement Payment ROD") and the related contracts and amendments. On October 11, 2007, the court issued an opinion stating that it could not determine how Bonneville would treat the 2004 contract amendments in light of the ruling in the PGE Proceeding, and remanded that determination to Bonneville.

By orders dated October 11, 2007, the court remanded to Bonneville for consideration in light of the PGE Proceeding and the Golden Northwest Proceeding the 2004 amendatory agreements to the Residential Exchange Program Settlement Agreements and certain other provisions. Bonneville ceased making payments under the Residential Exchange Program Settlement Agreements and Bonneville has addressed and is addressing the foregoing court rulings with regard to the Residential Exchange Program. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

In response to the court's rulings regarding the Residential Exchange Settlement Agreements and Bonneville's 2002 Final power rates, Bonneville initiated the 2009 Supplemental Power Rate proceeding in February 2008 and separately initiated processes to establish new long-term and interim RPSAs and to revise the Average System Cost (ASC) Methodology that is a key element of the Residential Exchange Program. A Record of Decision on new RPSAs was issued September 4, 2008 and new RPSAs were signed in the fall of 2008 with the five regional IOUs that expected to qualify for Residential Exchange Program benefits in Fiscal Year 2009. The 2009 Supplemental Power Rate Proposal proceeding concluded with a Record of Decision dated September 22, 2008. This record of decision addressed the court's Residential Exchange Program rulings by determining the amounts overpaid to the IOUs under the Settlement Agreements (Look-back Amounts) and initiated the return of overpaid amounts to Preference Customers. It also established Fiscal Year 2009 power rates and Residential Exchange Program benefits for utilities participating in the Residential Exchange Program. Bonneville customers and other parties have initiated legal challenges to the Look-back Amount determinations, power rates, long-term and interim RPSAs and related matters. FERC granted final approval of Bonneville's 2009 Supplemental Power rates on July 16, 2009 and granted final approval of the revised ASC Methodology in September 2009. The litigation over the Residential Exchange Program is continuing in the Ninth Circuit Court. A ruling is not expected until at least Fiscal Year 2012.

In July 2009, Bonneville concluded the Final 2010 Power and Transmission Rate Proposal. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Loads and Related Contracts and Power Rates through Fiscal Year 2011." Parties have filed or are expected to file legal challenges to Bonneville's Residential Exchange Program benefits included in the Final 2010 Power and Transmission Rate Proposal, decision on how to recoup prior overpayments and PF Rates. Bonneville believes that some or all of the challenges filed are likely to be dismissed as premature since FERC has not issued final approval of the Final 2010 Power and Transmission Rate Proposal. Nonetheless, Bonneville expects that any such challenges are likely to be re-filed if and when FERC approves the rates and related matters.

Southern California Edison v. Bonneville Power Administration

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

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

Conversion from Sale to Exchange Mode ("Conversion Claim"). 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 sought damages in the amount of approximately $186,000,000.

Termination for Default ("Termination Claim"). In July 2001, Bonneville terminated the Sale and Exchange Agreement for default, citing SCE's failure to make timely energy returns and deliveries while the contract was in exchange mode. SCE filed a complaint in November 2004 seeking $22,000,000 in termination for convenience damages.

On June 5, 2006, Bonneville and SCE executed an agreement to settle the Conversion Claim and the Termination Claim, whereby Bonneville will make a settlement payment of $28.5 million plus interest to SCE in exchange for SCE's dismissing the two claims. The settlement agreement identifies two conditions precedent to final resolution: (i) SCE must obtain approval of the settlement from the California Public Utilities Commission ("CPUC"); and, (ii) Bonneville must complete a public review and comment process, and subsequently reaffirm the settlement. Payment by Bonneville is due when it receives a final resolution of its refund liability, if any, in the California refund proceedings. (The California refund proceedings are described in "POWER SERVICES—Customers and Other Power Contract Parties of Bonneville's Power Services—Effect on Bonneville of Developments in California Power Markets in 1999-2001.") SCE filed the proposed settlement with the CPUC and it has approved the settlement. Bonneville has completed its public review process, and reaffirmed the proposed settlement on August 2, 2006. As such, Bonneville accrued a liability of $28.5 million during Fiscal Year 2006. However, payment has yet to be made pending resolution of the California refund proceedings and any related litigation. Once final resolution of Bonneville's refund liability, if any, has been determined, Bonneville will pay SCE $28.5 million plus interest.

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. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Bonneville Ratemaking and Rates."

It is the opinion of Bonneville's General Counsel that if any rate were to be rejected, the sole remedy accorded would be a remand to Bonneville to establish a new rate. Bonneville's flexibility in establishing rates could be restricted by the rejection of a Bonneville rate, depending on the grounds for the rejection. Bonneville is unable to predict, however, what new rate it would establish if a rate were rejected. If Bonneville were to establish a rate that was lower than the rejected rate, a petitioner may be entitled to a refund in the amount overpaid. However, Bonneville is required by law to set rates to meet all of its costs. Thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

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.

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 revenues and expenses, of changes in capitalization and long-term liabilities and of cash flows present fairly, in all material respects, the financial position of the Federal Columbia River Power System (FCRPS) at September 30, 2009, and 2008, and the results of its operations and its cash flows for each of the three years ended September 30, 2009, and the changes in its capitalization and long-term liabilities for each of the two years ended September 30, 2009, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of FCRPS' management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Portland, Oregon
October 30, 2009

Financial Statements

46

Combined Balance Sheets

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

ASSETS

	2009	2008
Utility plant		
Completed plant	**$13,883,626**	$13,480,633
Accumulated depreciation	**(5,106,884)**	(4,933,348)
	8,776,742	8,547,285
Construction work in progress	**985,624**	890,883
Net utility plant	**9,762,366**	9,438,168
Nonfederal generation	**2,520,245**	2,492,645
Current assets		
Cash	**1,357,019**	1,731,238
U.S. Treasury market-based special securities	**14,554**	—
Accounts receivable, net of allowance	**112,251**	112,129
Accrued unbilled revenues	**172,842**	203,011
Materials and supplies, at average cost	**77,612**	75,719
Prepaid expenses	**24,652**	21,682
Total current assets	**1,758,930**	2,143,779
Other assets		
Regulatory assets	**5,112,346**	5,447,404
U.S. Treasury market-based special securities	**83,041**	—
Nonfederal nuclear decommissioning trusts	**167,232**	157,743
Deferred charges and other	**235,119**	176,045
Total other assets	**5,597,738**	5,781,192
Total assets	**$19,639,279**	$19,855,784

The accompanying notes are an integral part of these statements.

CAPITALIZATION AND LIABILITIES

	2009	2008
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 2,556,272**	$ 2,664,460
Federal appropriations	**4,392,405**	4,247,972
Borrowings from U.S. Treasury	**1,765,440**	1,745,500
Nonfederal debt	**6,244,954**	6,182,403
Total capitalization and long-term liabilities	**14,959,071**	14,840,335
Commitments and contingencies (Note 12)		
Current liabilities		
Federal appropriations	**3,784**	9,889
Borrowings from U.S. Treasury	**365,000**	440,400
Nonfederal debt	**319,980**	284,469
Accounts payable and other	**474,349**	588,275
Total current liabilities	**1,163,113**	1,323,033
Other liabilities		
Regulatory liabilities	**2,567,271**	2,665,517
IOU exchange benefits	**83,655**	69,600
Asset retirement obligations	**162,943**	159,800
Deferred credits	**703,226**	797,499
Total other liabilities	**3,517,095**	3,692,416
Total capitalization and liabilities	**$19,639,279**	**$19,855,784**

The accompanying notes are an integral part of these statements.

Combined Statements of Revenues and Expenses

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

	2009	2008	2007
Operating revenues			
Sales	**$2,742,770**	$2,897,347	$3,136,216
Derivative instruments	**(34,677)**	(30,564)	(6,519)
U.S. Treasury credits for fish	**99,499**	100,392	66,097
Miscellaneous revenues	**62,692**	69,443	72,846
Total operating revenues	**2,870,284**	3,036,618	3,268,640
Operating expenses			
Operations and maintenance	**1,578,421**	1,256,213	1,569,504
Purchased power	**317,543**	450,035	310,073
Nonfederal projects	**501,367**	479,493	343,321
Depreciation and amortization	**355,574**	358,064	351,787
Total operating expenses	**2,752,905**	2,543,805	2,574,685
Net operating revenues	**117,379**	492,813	693,955
Interest expense and (income)			
Interest expense	**326,494**	340,658	344,379
Allowance for funds used during construction	**(30,710)**	(32,057)	(33,172)
Interest income	**(77,355)**	(80,633)	(74,460)
Net interest expense	**218,429**	227,968	236,747
Net revenues (expenses)	**(101,050)**	264,845	457,208
Accumulated net revenues at Oct. 1	**2,664,460**	2,402,565	1,945,357
Irrigation assistance	**(7,138)**	(2,950)	—
Accumulated net revenues at Sept. 30	**$2,556,272**	$2,664,460	$2,402,565

The accompanying notes are an integral part of these statements.

Combined Statements of Changes in Capitalization and Long-Term Liabilities

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

Balance at Sept. 30	Accumulated Net Revenues	Federal Appropriations	Borrowings from U.S. Treasury	Nonfederal Debt	Total
2007	$2,402,565	$4,337,601	$2,240,500	$6,551,053	$15,531,719
Federal construction appropriations:					
Increase	—	70,929	—	—	70,929
Repayment	—	(150,669)	—	—	(150,669)
Borrowings from U.S. Treasury:					
Increase	—	—	350,000	—	350,000
Repayment	—	—	(404,600)	—	(404,600)
Nonfederal debt:					
Increase	—	—	—	58,242	58,242
Repayment	—	—	—	(142,423)	(142,423)
Net revenues	264,845	—	—	—	264,845
Irrigation assistance	(2,950)	—	—	—	(2,950)
2008	$2,664,460	$4,257,861	$2,185,900	$6,466,872	$15,575,093
Federal construction appropriations:					
Increase	—	176,887	—	—	176,887
Repayment	—	(38,559)	—	—	(38,559)
Borrowings from U.S. Treasury:					
Increase	—	—	338,000	—	338,000
Repayment	—	—	(393,460)	—	(393,460)
Nonfederal debt:					
Increase	—	—	—	287,944	287,944
Repayment	—	—	—	(189,882)	(189,882)
Net revenues	(101,050)	—	—	—	(101,050)
Irrigation assistance	(7,138)	—	—	—	(7,138)
2009	$2,556,272	$4,396,189	$2,130,440	$6,564,934	$15,647,835

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

	2009	2008	2007
Cash provided by and (used for) operating activities			
Net revenues	$ (101,050)	$ 264,845	$ 457,208
Noncash items:			
Depreciation and amortization	355,574	358,064	351,787
Unrealized loss on derivative instruments	34,706	30,535	6,641
Changes in:			
Receivables and unbilled revenues	32,561	6,721	62,736
Materials and supplies	(1,893)	(7,385)	3,431
Prepaid expenses	(2,970)	(1,744)	1,515
Accounts payable and other	(138,548)	240,592	(23,245)
Regulatory assets and liabilities	165,351	1,035,611	186,876
Other assets and liabilities	(135,690)	(1,054,411)	(174,664)
Cash provided by operating activities	208,041	872,828	872,285
Cash provided by and (used for) investing activities			
Investment in:			
Utility plant (including AFUDC)	(575,083)	(412,055)	(435,758)
Nonfederal generation	(27,600)	(27,415)	(30,165)
Transfer from Spectrum Relocation Fund	—	—	48,627
U.S. Treasury market-based special securities:			
Purchases	(110,000)	—	—
Maturities	9,891	—	—
Nonfederal nuclear decommissioning trusts	(8,211)	(7,300)	(6,691)
Special purpose corporations' trust funds:			
Deposits to	(199,916)	(74,474)	(51,070)
Receipts from	108,081	65,779	5,955
Cash used for investing activities	(802,838)	(455,465)	(469,102)
Cash provided by and (used for) financing activities			
Federal construction appropriations:			
Increase	176,887	70,929	125,972
Repayment	(38,559)	(150,669)	(112,100)
Borrowings from U.S. Treasury:			
Increase	338,000	350,000	265,000
Repayment	(393,460)	(404,600)	(506,300)
Nonfederal debt:			
Increase	287,944	58,242	66,148
Repayment	(189,882)	(142,423)	(30,353)
Customers:			
Advances for construction	63,492	70,356	44,434
Reimbursements to customers	(16,706)	(10,554)	(5,515)
Irrigation assistance	(7,138)	(2,950)	—
Cash provided by (used for) financing activities	220,578	(161,669)	(152,714)
(Decrease) increase in cash	(374,219)	255,694	250,469
Beginning cash balance	1,731,238	1,475,544	1,225,075
Ending cash balance	$1,357,019	$1,731,238	$1,475,544
Cash paid for interest, net of U.S. Treasury credits	$ 181,454	$ 160,586	$ 243,010
Supplemental schedule of noncash operating activities:			
Interest credits	$ 73,839	$ 108,385	$ 64,104
U.S. Treasury credits	$ 111,492	$ 114,753	$ 87,453

The accompanying notes are an integral part of these statements.

Notes to Financial Statements

1. Summary of Significant Accounting Policies

ACCOUNTING PRINCIPLES

Combination and consolidation of entities

The Federal Columbia River Power System (FCRPS) financial statements combine the accounts of the Bonneville Power Administration (BPA), the accounts of the Pacific Northwest generating facilities of the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) as well as the operation and maintenance costs of the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan facilities. Consolidated with BPA are "Special Purpose Corporations" known as Northwest Infrastructure Financing Corporations (NIFCs), from which BPA leases certain transmission facilities (see Note 8, Nonfederal Debt).

BPA is the power marketing administration that purchases, transmits and markets power for the FCRPS. Each of the combined entities is separately managed and financed, but the facilities are operated as an integrated power system with the financial results combined as the FCRPS. While the costs of Corps and Reclamation projects serve multiple purposes, only the power portion of total project costs are assigned to the FCRPS through a cost-allocation process. All intracompany and intercompany accounts and transactions have been eliminated from the combined financial statements.

FCRPS accounts are maintained in accordance with generally accepted accounting principles of the United States of America 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 directives issued by U.S. government agencies. BPA is a component of the U.S. Department of Energy; Reclamation and U.S. Fish and Wildlife Service are part of the U.S. Department of the Interior; and the Corps is part of the U.S. Department of Defense. U.S. government properties and income are tax-exempt.

Use of estimates

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

Reclassifications

Certain reclassifications were made to the fiscal years 2007 and 2008 combined financial statements from amounts previously reported to conform to the presentation used in fiscal year 2009. Such reclassifications had no effect on previously reported results of operations or cash flows.

Rates and regulatory authority

BPA establishes separate power and transmission rates in accordance with several statutory directives. Rates proposed by BPA are subjected to an extensive formal review process, after which they are proposed by BPA and reviewed by FERC. FERC's review is limited to three standards set out in the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. 839, and a standard set out by the Energy Policy Act of 1992, 16 U.S.C. 824. 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 (Ninth Circuit Court). Action seeking such review must be filed within 90 days of the final FERC decision. The Ninth Circuit Court may either confirm or reject a rate proposed by BPA.

In accordance with authoritative guidance for Regulated Operations (see Note 3, Effects of Regulation) certain costs or credits may be included in rates for recovery over a future period and are recorded as regulatory assets or liabilities. Regulatory assets or liabilities are amortized over the periods they are included in rates. Costs are recovered through rates during the periods when the costs are scheduled to be repaid. Amortization is computed using either the straight-line method or is based upon specific amounts included in rates each year. When the straight-line method is used, it is based upon either the estimated service lives or the periods the costs are included in rates. Since BPA's rates are not structured to provide a rate of return on rate base assets, regulatory assets are recovered at cost without an additional rate of return.

Utility plant

Utility plant is stated at original cost and primarily includes generation and transmission assets. Generation assets were $7.6 billion and $7.3 billion, and transmission assets were $6.3 billion and $6.2 billion at Sept. 30, 2009, and 2008, respectively. The costs of additions, major replacements and substantial betterments are capitalized. 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. Maintenance, repairs and replacements of items determined to be less than major units of property are charged to maintenance and operating expense as incurred. The cost of retiring utility plant units less any salvage proceeds is charged to accumulated depreciation when removed from service.

Depreciation

Depreciation of the original cost of generation plant is computed on the straight-line method based on estimated service lives of the various classes of property, which average 75 years. For transmission plant, depreciation of original cost and estimated cost of retirement (i.e., net cost of removal) is computed on the straight-line method based on estimated service lives of the various classes of property, which average 40 years. The net cost of removal (the difference between cost of removal and salvage value) is included in depreciation rates; however, in the event there is negative salvage (the cost of removal exceeds salvage value), a reclassification of the negative salvage reserve not associated with asset retirement obligations is made from accumulated depreciation to a regulatory liability.

Allowance for funds used during construction

Allowance for funds used during construction (AFUDC) represents the estimated cost of interest on financing the construction of new assets. AFUDC is based on the construction work in progress balance and is charged to the capitalized cost of the utility plant asset. AFUDC is a noncash reduction of interest expense.

FCRPS capitalizes AFUDC at one rate for Corps and Reclamation construction funded by congressional appropriations and at another rate for construction funded substantially by BPA. The rates for appropriated funds are provided each year to BPA by the U.S. Treasury, whereas the BPA rate is determined based on BPA's weighted-average cost of borrowing. The respective rates were approximately 2.0 percent and 5.2 percent in fiscal year 2009, 4.3 percent and 5.4 percent in fiscal year 2008, and 5.1 percent and 5.1 percent in fiscal year 2007.

Nonfederal generation

BPA has acquired all of the generating capability of Energy Northwest's Columbia Generating Station (CGS) nuclear power plant. The contracts to acquire the generating capability of the project require BPA to pay all or part of the annual project budget, including operating expense and debt service. BPA also has acquired all of the output of the Cowlitz Falls hydro project and pays all operating expense and debt service. BPA recognizes expenses for these projects based upon total project cash funding requirements. The nonfederal generation assets in the Combined Balance Sheets represent intangible assets equal to the related nonfederal debt associated with those generation assets. These intangible assets are amortized as the principal on the outstanding bonds is repaid by the nonfederal entities (see Note 8, Nonfederal Debt).

Cash

For purposes of reporting cash flows, amounts include cash in the BPA fund and unexpended appropriations of the Corps and Reclamation. The BPA fund with the U.S. Treasury consists of the BPA public enterprise fund and the Corps allocation transfer account that may be used to make expenditures without further appropriation and without fiscal year limitation.

U.S. Treasury market-based special securities

In 2009, BPA began participating in the U.S. Treasury's Federal Investment Program. Through this program, the U.S. Treasury provides investment services to federal government entities that have funds on deposit with the U.S. Treasury and have legislative authority to invest those funds. Investments of the funds are generally restricted to special non-marketable securities, also called market-based specials. Under its new banking arrangement with the U.S. Treasury, BPA has agreed to invest at least $100 million annually for up to 10 years or until the BPA fund is fully invested. U.S. Treasury market-based specials acquired during fiscal year 2009 have maturities of up to five years and weighted-average yield of 2.1 percent. BPA follows the authoritative guidance for Investments for Debt and Equity Securities. Investments are classified as held-to-maturity and reported at amortized cost. Investments with maturities that will be realized in cash within one year are classified as current assets. At Sept. 30, 2009, the amortized cost and fair value of these investments were $97.6 million and $99.7 million, respectively.

Concentrations of credit risks

General credit risk

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

BPA's accounts receivable are spread across a diverse group of public utilities, investor-owned utilities (IOUs), power marketers, wind generators and others that are located throughout the Western United States and Canada. The accounts receivable exposure results 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 years 2009, 2008 and 2007, BPA experienced no significant losses as a result of any customer defaults or bankruptcy filings.

Credit risk is mitigated at BPA by reviewing counterparties for creditworthiness, establishing credit limits and monitoring credit exposure on a daily basis. In order to further manage credit risk, BPA obtains credit support, such as letters of credit, parental guarantees, cash in the form of prepayment, and deposit or escrow from some counterparties. Counterparties are monitored closely for changes in financial condition and credit reviews are updated regularly.

Allowance for doubtful accounts

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

The largest risk relates to the California power markets that were in turmoil during 2000 to 2001 when they experienced historically high power prices and volatility, along with continued uncertainty related to deregulation. The California Independent System Operator and California Power Exchange were customers with whom BPA had contracts for power and transmission delivery during that period and they have been unable to fully pay BPA for their purchases. BPA has recorded an allowance for doubtful accounts, which in management's best estimate is sufficient to cover potential exposure. Net exposure after the allowance is not significant. BPA has continued to pursue collection of amounts due.

Post-retirement benefits

Federal employees associated with the operation of the FCRPS are participants in either the Civil Service Retirement System (CSRS) or the Federal Employees Retirement System (FERS). Both federal employers and their employees contribute a percentage of eligible employee compensation toward funding these post-retirement benefit plans. Based on the statutory agency contribution rates, retirement benefit expense under CSRS is equivalent to 7 percent of eligible employee compensation and under FERS is equivalent to 11.2 percent of eligible employee compensation. The legislatively mandated contribution levels for CSRS and FERS do not fully cover the cost to the federal government to provide the plan benefits. Therefore, the programs are considered underfunded (see Note 12, Commitments and Contingencies). Employees also may participate in the Federal Employees Health Benefits Program and/or the Federal Employees' Group Life Insurance Program, which are similarly underfunded. Retirement benefits under the federal retirement systems are payable by the U.S. Treasury.

Derivative instruments

BPA follows the Derivatives and Hedging accounting guidance that requires every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and also requires that a change in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

It is BPA's policy to document and apply as appropriate the normal purchase and normal sales exception under the Derivatives and Hedging accounting guidance. Purchases and sales of forward electricity contracts are generally considered normal purchases and normal sales if they require physical delivery, are expected to be used or sold by BPA in the normal course of business and meet the definition of capacity described in the Derivatives and Hedging accounting guidance. These transactions are not required to be recorded at fair value in the financial statements. Recognition of these contracts in Sales or Purchased power costs in the Combined Statements of Revenues and Expenses occurs when the contracts settle.

Fair value

BPA's carrying amounts of current assets and current liabilities approximates fair value based on the short-term nature of these instruments. In accordance with authoritative guidance for Fair Value Measurements and Disclosures, BPA uses fair value measurements to record adjustments to certain financial assets and liabilities and to determine fair value disclosures. When developing fair value measurements, it is BPA's policy to use quoted market prices whenever available, or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Fair values are primarily developed using industry standard models that consider various inputs including: (a) quoted forward prices for commodities; (b) time value; (c) volatility factors; (d) current market and contractual prices for underlying instruments; (e) market interest rates and yield curves; and (f) credit spreads, as well as other relevant economic measures (see Note 10, Risk Management and Derivative Instruments and Note 11, Fair Value Measurements).

Revenues and net revenues

Operating revenues are recorded when services are rendered and include estimated unbilled revenues of $172.8 million, $203.0 million and $181.5 million at Sept. 30, 2009, 2008 and 2007, respectively.

Because BPA is a federal government power marketing administration, net revenues over time are committed to repayment of the U.S. government investment in the FCRPS, the payment of certain irrigation costs (see Note 12, Commitments and Contingencies) and the payment of operational obligations, including debt for both operating and nonoperating nonfederal projects.

Interest income

Interest income represents both interest earned on BPA's fund balance with the U.S. Treasury in the form of interest credits and interest earned on investments in market-based special securities. BPA continues to earn interest at the weighted-average interest rate of its outstanding federal borrowings debt based on daily fund balances. Such interest is not received in cash but is applied as a noncash reduction to monthly debt interest payments to the U.S. Treasury. Under the new banking arrangement with the U.S. Treasury signed in April 2008, BPA began investing in market-based special securities as of Oct. 1, 2008. Interest earnings on investments are dependent on the performance of the market-based special securities and interest earned is a cash receipt.

U.S. Treasury credits for fish

The Pacific Northwest Electric Power Planning and Conservation Act of 1980 obligates the BPA administrator to make expenditures for fish and wildlife protection, mitigation and enhancement for both power and nonpower purposes on a reimbursement basis. The Northwest Power Act also specifies that consumers of electric power, through their rates for power services, "shall bear the costs of measures designed to deal with adverse impacts caused by the development and operation of electric power facilities and programs only." Section 4(h)(10)(C) of the Northwest Power Act was designed to ensure that the costs of mitigating these impacts are properly accounted for among the various purposes of the hydroelectric projects. As such, BPA reduces its cash payments to the U.S. Treasury by an amount equal to the mitigation measures funded on behalf of the nonpower purposes.

Residential Exchange Program

In order to provide regional utilities, primarily IOUs, access to benefits from the FCRPS, Congress established the Residential Exchange Program (REP) in Section 5(c) of the Northwest Power Act. Whenever a Pacific Northwest electric utility offers to sell power to BPA at the utility's average system cost (ASC) of resources, BPA purchases such power and offers, in exchange, to sell an equivalent amount of power at BPA's Priority Firm (PF) Exchange rate to the utility for resale to that utility's residential and small farm consumers. REP costs are forecast for each year of the rate period and included in the revenue requirement for establishing rates. They are collected in rates with program costs recognized when incurred net of the purchase and sale of power under the REP.

In fiscal year 2008, BPA filed the 2007 Supplemental Wholesale Power Rate Case (WP-07 Supplemental Rate Case) to resolve outstanding claims and associated judicial rulings related to prior REP billings. In connection with that filing, Lookback Amounts due to and due from BPA customers were identified and recorded as regulatory amounts. Such Lookback Amounts are being collected from identified IOU customers and are being returned to the Consumer-Owned Utilities (COUs) over time. In each succeeding rate case, the BPA administrator designates the amount to be recovered from the IOUs and returned to each qualifying COU. These amounts do not reduce rates, but are reflected as credits to qualifying COUs' bills as designated in the corresponding Final Record of Decision (ROD). BPA recognizes a refund and reduces expense in the year it is applied, until the Lookback Amount is eliminated. These transactions are net operating revenue neutral as the same amount reduces both revenue and expense (see Note 4, Residential Exchange Program).

RECENT ACCOUNTING PRONOUNCEMENTS

Fair value measurements and disclosures

This standard provides guidance for using fair value to measure assets and liabilities that currently require fair value measurement. It applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances. The guidance establishes a fair value hierarchy that prioritizes the information used to develop measurement assumptions and became effective for BPA on Oct. 1, 2008 (see Note 11, Fair Value Measurements). The adoption of this guidance did not materially impact BPA's financial condition, results of operations or cash flows.

There was additional clarifying guidance issued in fiscal year 2009, related to fair value measurements regarding the exclusion of leasing transactions, deferral of nonfinancial assets and liabilities, observable inputs in active markets which are not available and valuation in inactive markets. The adoption of these new standards did not materially impact BPA's financial condition, results of operations or cash flows.

Derivatives and hedging

Effective for fiscal year 2009, BPA adopted new accounting standards for derivatives and hedging, which requires enhanced disclosures on derivative instruments and hedging activities. These updates expand the disclosure requirements for derivative instruments and hedging activities. This new guidance is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable financial statement readers to better understand how and why an entity uses derivative instruments and their effects on an entity's financial position, financial performance and cash flows (see Note 10, Risk Management and Derivative Instruments). The adoption of this new standard resulted in increased disclosures only.

Subsequent events

Effective for fiscal year 2009, FCRPS adopted new accounting standards for subsequent events. This standard establishes principles and disclosure requirements for events or transactions that occur after the balance sheet date but before financial statements are issued or are available to be issued. The implementation of this guidance did not materially impact FCRPS' financial condition, results of operations or cash flows.

Generally accepted accounting principles

This standard establishes Accounting Standards Codification as the single official source of authoritative, nongovernmental U.S. generally accepted accounting principles. BPA adopted this standard in fiscal year 2009.

Variable Interest Entity

In June 2009, the Financial Accounting Standards Board issued SFAS No. 167, "Amendments to FASB Interpretation No. 46(R)." This statement requires an analysis to determine whether BPA's Variable Interest Entities (VIEs) provide BPA with a controlling financial interest in the VIEs. The statement defines the primary beneficiary of the VIE as the entity having power to control the activities that most significantly impact the performance. The primary beneficiary is also defined as having the obligation to absorb losses or the right to receive benefits from the entity that could potentially be significant to the VIE. This guidance will be effective for fiscal year 2011. BPA is evaluating the impact on BPA's financial statements.

SUBSEQUENT EVENTS

FCRPS has performed an evaluation of events and transactions for potential recognition or disclosure through Oct. 30, 2009, which is the date the financial statements were issued.

2. Asset retirement obligations

As of Sept. 30 — thousands of dollars

	2009	2008
Beginning Balance	**$ 159,800**	$ 175,500
Activities:		
Accretion	**7,739**	7,200
Expenditures	**(1,501)**	(2,600)
Revisions	**(3,095)**	(20,300)
Ending Balance	**$ 162,943**	$ 159,800

BPA recognizes asset retirement obligations (ARO) according to the estimated fair value of the dismantlement and restoration costs associated with the retirement of tangible long-lived assets. The liability is adjusted for any revisions, expenditures and the passage of time. FCRPS also has certain tangible long-lived assets such as federal hydro projects without an associated ARO.

AROs include the following items as of Sept. 30, 2009:

- CGS decommissioning and site restoration of $120.4 million;
- Trojan decommissioning of $23.6 million;
- Project Nos. 1 and 4 site restoration of $15.0 million;
- BPA owned transmission assets of $3.9 million.

In fiscal years 2009 and 2008, BPA reduced the Trojan decommissioning ARO liability by $3.5 million and $19.9 million, respectively, to reflect changes in the settlement of demolition activities, reduction in the estimated annual cash flows related to spent fuel operations and adjustments for other decommissioning activities.

NONFEDERAL NUCLEAR DECOMMISSIONING TRUSTS

BPA recognizes an asset that represents trust fund balances for decommissioning and site restoration costs. Decommissioning costs for CGS are charged to operations over the operating life of the project. An external trust fund for decommissioning costs is funded monthly for CGS. The trust funds are expected to provide for decommissioning at the end of the project's safe storage period in accordance with the Nuclear Regulatory Commission (NRC) requirements. The NRC requires that this period be no longer than 60 years from the time the plant stops operating. The plant is licensed to operate until the current operating license termination year of 2024. Trust fund requirements for CGS are based on a NRC decommissioning cost estimate and the license termination date.

The fair value of funds set aside in BPA's decommissioning and sites restoration trust funds totaled $167.2 million and $157.7 million at Sept. 30, 2009, and 2008, respectively. The funds are invested in cash equivalents, equity and fixed income funds. BPA's investment securities in the trust are classified as available-for-sale in accordance with accounting guidance related to Investments, Debt and Equity Securities. Payments to the trusts for fiscal years 2009, 2008 and 2007 were approximately $8.2 million, $7.3 million and $6.7 million, respectively.

BPA directly funds Eugene Water and Electric Board's 30 percent share of Trojan's decommissioning costs through current rates. Decommissioning costs are included in Operations and maintenance expense in the accompanying Combined Statements of Revenues and Expenses.

3. Effects of regulation

REGULATORY ASSETS

As of Sept. 30 — thousands of dollars

	2009	2008
Terminated nuclear facilities	**$ 3,550,170**	$3,674,815
REP Lookback Amount from IOUs	**624,496**	679,012
Columbia River Fish Mitigation	**413,304**	370,332
Conservation measures	**165,485**	191,300
Fish and wildlife measures	**158,221**	153,618
Settlements	**49,409**	46,533
Federal Employees' Compensation Act	**34,341**	34,478
Spacer damper replacement program	**30,436**	28,677
Sponsored conservation	**25,690**	29,555
Terminated hydro facilities	**23,780**	24,725
Trojan decommissioning and site restoration	**23,546**	27,544
Capital bond premiums	**12,373**	13,608
Other	**1,095**	—
Direct-service industries' benefits	**—**	173,207
Total Regulatory Assets	**$5,112,346**	$5,447,404

Regulatory assets include the following items:

- "Terminated nuclear facilities" include the nonfederal debt for Energy Northwest Nuclear Project Nos. 1 and 3. These assets are amortized as the principal on the outstanding bonds is repaid (see Note 8, Nonfederal Debt).
- "REP Lookback Amount from IOUs" is the amount recoverable from IOUs in future rate cases that reduces their benefit payments. These costs will be recovered and amortized through future rates over a period as established by the administrator until the Lookback Amount is eliminated (see Note 4, Residential Exchange Program).
- "Columbia River Fish Mitigation" is the cost of research and development for fish bypass facilities funded through appropriations since 1989 in accordance with the Energy and Water Development Appropriations Act of 1989, Public Law 100-371. These costs will be recovered through future rates and amortized as scheduled over 75 years.
- "Conservation measures" consist of the costs of capitalized conservation measures and are amortized over periods from five to 20 years.
- "Fish and wildlife measures" consist of capitalized fish and wildlife projects and are amortized over a period of 15 years.
- "Settlements" reflect costs related to settlement agreements resulting from litigation. These costs will be recovered and amortized through future rates over a period as established by the administrator.
- "Federal Employees' Compensation Act" reflects the actuarial estimated amount of future payments for current recipients of BPA's worker compensation benefits.
- "Spacer damper replacement program" consists of costs to replace deteriorated spacer dampers that have been deferred and are being recovered in rates under the Spacer Damper Replacement Program. These costs are being amortized over a period of 30 years.
- "Sponsored conservation" relates to the nonfederal debt for Emerald People's Utility District loans, Conservation and Renewable Energy System and City of Tacoma Conservation bonds. These were issued to finance conservation programs sponsored by BPA. The assets are amortized as the principal on the outstanding bonds is repaid.
- "Terminated hydro facilities" include the nonfederal debt for the terminated Northern Wasco hydro project. These assets are amortized as the principal on the outstanding bonds is repaid.
- "Trojan decommissioning and site restoration" costs reflect the amount to be recovered in future rates for funding the Trojan ARO liability (see Note 2, Asset Retirement Obligations).
- "Capital bond premiums" are the deferred losses related to refinanced debt and are amortized over the life of the new debt instruments.
- "Direct-service industries' (DSI) benefits" were expected DSI payments to be made in the future and included in rates. In fiscal year 2009 the liabilities associated with this program were eliminated as the agreements giving rise to these liabilities were invalidated by the Ninth Circuit Court.

REGULATORY LIABILITIES

As of Sept. 30 — thousands of dollars

	2009	2008
Capitalization adjustment	**$1,731,606**	$1,796,511
REP Lookback Amount to COUs	**624,496**	679,012
Accumulated plant removal costs	**172,925**	157,492
CGS decommissioning and sites restoration	**33,644**	28,877
Other	**4,600**	3,625
Total Regulatory Liabilities	**$2,567,271**	$2,665,517

Regulatory liabilities include the following items:

- "Capitalization adjustment" is the difference between appropriated debt before and after refinancing per the BPA Refinancing Section of the Omnibus Consolidated Rescissions and Appropriations Act of 1996 (Refinancing Act), 16 U.S.C. 838(l). The adjustment is being amortized over the remaining period of repayment so that total FCRPS net interest expense is equal to what it would have been in the absence of the Refinancing Act. Amortization of the capitalization adjustment was $64.9 million for fiscal years 2009, 2008 and 2007, respectively.
- "REP Lookback Amount to COUs" is the amount previously collected through rates that is owed qualifying consumer-owned utilities and will be credits on their future bills. These costs will be repaid and amortized through future rates over a period as established by the administrator until the Lookback Amount is eliminated (see Note 4, Residential Exchange Program).
- "Accumulated plant removal costs" is the amount previously collected through rates as part of depreciation. These costs will be relieved as actual removal costs are paid.
- "CGS decommissioning and sites restoration" is the amount previously collected through rates in excess of the ARO balances for CGS decommissioning and site restoration as well as Project Nos. 1 and 4 sites.

4. Residential Exchange Program

BACKGROUND

As provided in the Northwest Power Act, beginning in 1981 BPA entered into 20-year Residential Purchase and Sale Agreements (RPSAs) with eligible regional utility customers. The RPSAs implemented the REP.

In 2000, BPA signed Residential Exchange Program Settlement Agreements ("REP settlements" or "settlement agreements") with the region's six IOUs under which BPA provided monetary and power benefits as a settlement of residential exchange disputes for the period July 1, 2001, through Sept. 30, 2011. BPA later signed additional agreements and amendments related to the settlement agreements with IOU customers. One such agreement provided for the elimination or deferral of certain IOU benefit payments, while later agreements and amendments provided for minimum and maximum amounts for the IOU monetary benefits for fiscal years 2007 through 2011, provided that BPA would have no obligation to provide power to the IOUs in this period. When future amounts were committed through these agreements, BPA recorded a REP settlement liability for the minimum committed amounts, and a regulatory asset for amounts recoverable in future rates.

LOOKBACK AMOUNT

In May 2007, the Ninth Circuit Court ruled that the REP settlements were inconsistent with the Northwest Power Act and that BPA improperly allocated settlement costs to BPA's preference rates. In response to that ruling, in fiscal year 2008 BPA reduced the REP settlement agreement liability and regulatory asset to zero and conducted the WP-07 Supplemental Rate Case.

On Sept. 22, 2008, the BPA administrator issued a Final ROD that revised power rates for fiscal year 2009, and determined the amount the COUs were overcharged in prior years. The prior overcharges, which amount to $746.2 million for fiscal years 2002 through 2006, are labeled the "Lookback Amount" in the Final ROD. This Lookback Amount represents amounts over collected from COUs in prior years' rates, which also represents the amounts overpaid to the IOUs under the settlement agreements in prior years. As described in the WP-07 Supplemental Rate Case, the BPA administrator designated the amount to be recovered from the IOUs and returned to each qualifying COU. These amounts do not reduce rates, but are applied as credits to qualifying COUs as designated in the corresponding Final RODs. BPA recognizes the refund and reduces expense in the year it is applied. These transactions are net revenue neutral as the same amount reduces both revenue and expense. The Lookback Amount is recorded as both a regulatory asset, representing amounts to be collected from IOUs in the future in rates, and a regulatory liability, representing amounts to be credited to the COUs in future rates.

After recording the Lookback Amount applied for fiscal year 2008 of $67.2 million, the Lookback Amount ending balance as of Sept. 30, 2008 was $679.0 million. In 2009, BPA adjusted both the regulatory liability and regulatory asset by $83.3 million to reflect the $70.8 million Lookback Amount applied in fiscal year 2009 as scheduled in the Final ROD and the $12.5 million Lookback Amount applied for the Avista deemer settlement discussed in the 2009 Deemer Adjustment section. In addition, interest of $28.8 million was applied to the outstanding balance for an account balance of $624.5 million as of Sept. 30, 2009.

In response to the Ninth Circuit Court ruling that the REP settlement agreements were inconsistent with the Northwest Power Act, BPA returned to a purchase and sale exchange similar to that in effect prior to the REP settlement agreements.

IOU EXCHANGE BENEFITS

In fiscal year 2008, Interim Agreements were executed to provide certain IOUs with temporary REP benefits for their residential and small farm consumers. These agreements included a provision to true-up the amounts advanced with the actual REP benefits for fiscal year 2008. The true-up amount for the IOUs was $69.6 million; however, provisions in the agreement provided that true-up payments can not be paid until any subsequent legal challenges to BPA's final ROD, if any, are resolved (see Note 12, Commitments and Contingencies). In 2009, BPA reached a settlement with Avista, described below, over their disputed deemer balance which resulted in the amount due to them for their 2008 benefits changing from zero to $12.0 million and an increase in the IOU exchange benefits balance to $81.6 million. After applying interest for fiscal year 2009, this balance has increased to $83.6 million.

2009 DEEMER ADJUSTMENT

In June 2009, BPA reached a settlement regarding the long-standing dispute with Avista Corporation over the REP deemer account provisions. Deemer balances result when a REP exchanging utility's ASC is below the BPA PF Exchange rate. Rather than resulting in a requirement of the exchanging utility to pay BPA for the exchange, the utility deems its ASC to be equal to the PF Exchange rate. The amount that otherwise would have been owed to BPA is accumulated and offset against future benefits until the deemer account is reduced to zero. Upon elimination of the deemer account balance, the exchanging utility is entitled to receive payment for exchange benefits. The settlement with Avista sets the beginning fiscal year 2002 deemer balance to $55.0 million, rather than the disputed deemer account balance of $85.6 million.

As discussed above, as part of the WP-07 Supplemental Rate Case, BPA established reconstructed REP benefits and determined the amounts that IOUs were overpaid under the REP settlement agreements the Ninth Circuit Court held to be unlawful. These overpayments, and whether a utility has a deemer account balance under the new RPSAs, depend in part on what the deemer account balance is assumed to be as of Oct. 1, 2001. With the settled deemer balance at the beginning of fiscal year 2002 being lower than that which was used to calculate the reconstructed REP benefits and deemer account balance, Avista receives exchange benefits sooner than they otherwise would have using the disputed account balance. Under the settlement agreement, the reconstruction of exchange benefits results in Avista being eligible for benefits in fiscal year 2008 rather than in the last quarter of fiscal year 2009.

The accumulated effect of the Avista settlement results in higher REP expenses recorded in fiscal year 2009 of $20.5 million and lower revenues due to the effect of the Avista Lookback Amount applied of $12.5 million that is recorded as revenue subject to refund. The total effect is a reduction to Net revenue of $33.0 million for fiscal year 2009.

5. Deferred charges and other

As of Sept. 30 — thousands of dollars

	2009	2008
Special purpose corporations' trust funds	**$ 157,295**	$ 72,482
Derivative instruments	**32,206**	40,963
Spectrum Relocation fund	**30,595**	39,243
Other	**10,670**	11,670
Energy receivable	**4,353**	11,687
	$235,119	$176,045

Deferred charges and other include the following items:

- "Special purpose corporations' trust funds" are amounts held in separate trust accounts for the construction of transmission assets, debt service payments during the construction period and a fund mainly for future principal and interest debt service payments (see Note 8, Nonfederal Debt).
- "Derivative instruments" represent unrealized gains from the derivative portfolio which includes physical power purchase and sale transactions, power exchange transactions, and power and heat rate option contracts.
- The Commercial Spectrum Enhancement Act created the "Spectrum Relocation fund" to reimburse the costs of replacing radio communication equipment displaced as a result of radio band frequencies no longer available to federal agencies. Amounts received from the U.S. Treasury in connection with the Act are restricted for use in constructing replacement assets.
- "Energy receivable" is energy to be returned to BPA for prior transmission line losses and over delivery.

6. Federal appropriations

Appropriations consist primarily of the power portion of Corps and Reclamation capital investments that had been funded through congressional appropriations and the remaining unpaid capital investments in the BPA transmission system, which were made prior to implementation of the Federal Columbia River Transmission System Act of 1974, 16 U.S.C. 838(j). Federal appropriations exclude future capital replacements and irrigation assistance.

The Refinancing Act required that the outstanding balance of the FCRPS federal appropriations be reset and assigned market rates of interest prevailing as of Oct. 1, 1996. This resulted in a determination that the principal amount of appropriations should 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. Appropriations in the amount of $6.6 billion were subsequently refinanced for $4.1 billion. This adjustment was recorded as a capitalization adjustment in regulatory liabilities and is being amortized over the remaining period of repayment.

Prior to the mid-1990s, construction and replacement of Corps and Reclamation generating facilities were financed through federal appropriations to the Corps and Reclamation. Annual appropriations were also made for operation and maintenance costs, to be 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, in lieu of congressional appropriations, BPA directly funds most operation and maintenance expenses as well as 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. Federal appropriations may be paid early without penalty.

The weighted-average interest rate was 6.5 percent and 6.6 percent on outstanding appropriations as of Sept. 30, 2009, and 2008, respectively.

MATURING FEDERAL APPROPRIATIONS

As of Sept. 30 — thousands of dollars

2010	$ 3,784
2011	21,232
2012	24,622
2013	18,250
2014	19,198
2015 and thereafter	4,309,103
	$4,396,189

7. Borrowings from U.S. Treasury

BPA is authorized by Congress to issue to the U.S. Treasury and have outstanding at any one time, up to $7.70 billion of interest-bearing debt with terms and conditions comparable to debt issued by U.S. government corporations in order to finance its capital programs, which include Corps and Reclamation direct-funded capital investments. In February 2009, Section 401 of the American Recovery and Reinvestment Act increased BPA's authority of $4.45 billion by an additional $3.25 billion. Of the $7.70 billion, $1.25 billion is reserved for conservation and renewable resources.

At Sept. 30, 2009, of the total $2.13 billion of outstanding bonds, $677.8 million were conservation and renewable resources investments. The weighted-average interest rate of BPA's borrowings from the U.S. Treasury exceeds the rate that could be obtained currently by BPA. As a result, the fair value of BPA's U.S. Treasury borrowings exceeded the carrying value by approximately $189.6 million and $109.6 million, based on discounted future cash flows using agency rates offered by the U.S. Treasury as of Sept. 30, 2009, and 2008, respectively, for similar maturities.

The weighted-average interest rate on outstanding U.S. Treasury borrowings was 5.0 percent and 5.2 percent as of Sept. 30, 2009, and 2008, respectively.

MATURING DEBT

As of Sept. 30 — thousands of dollars

2010	$ 365,000
2011	325,000
2012	265,000
2013	122,800
2014	103,000
2015 through 2039	949,640
	$2,130,440

8. Nonfederal debt

PROJECTS FINANCED WITH NONFEDERAL DEBT

As of Sept. 30 — thousands of dollars

	2009	2008
Terminated nuclear facilities:		
Nuclear Project No. 1	**$ 1,821,165**	$ 1,863,790
Nuclear Project No. 3	**1,729,005**	1,811,025
Terminated nuclear facilities	**3,550,170**	3,674,815
Nonfederal generation:		
Columbia Generating Station	**2,392,475**	2,359,765
Cowlitz Falls	**127,770**	132,880
Nonfederal generation	**2,520,245**	2,492,645
Lease financing program	**445,049**	245,132
Sponsored conservation:		
CARES	**16,065**	18,345
Tacoma	**9,625**	11,005
Emerald	—	205
Sponsored conservation	**25,690**	29,555
Northern Wasco	**23,780**	24,725
	$ 6,564,934	$ 6,466,872

Prior to commercial operations, BPA acquired 100 percent of Energy Northwest's Nuclear Project No. 1 and 70 percent of Nuclear Project No. 3. The contracts require BPA to pay all or part of the projects' annual budgets, including maintenance expense and debt service on bonds issued by nonfederal entities. Nuclear Project No. 1 and Nuclear Project No. 3 were terminated prior to completion.

BPA acquired all of the generating capability of the CGS nuclear generating project (formerly Project No. 2) and Cowlitz Falls hydro project and agreed to pay the maintenance and debt service costs.

Related assets for operating projects are included in nonfederal generation. Nonoperating projects are included in regulatory assets.

The underlying debt for these Energy Northwest obligations (comprising terminated nuclear facilities and nonfederal generation) matures through 2024 with interest rates that are primarily fixed between 3.0 percent and 7.1 percent.

The fair value of Energy Northwest debt exceeded recorded value by $647.0 million and $36.9 million as of Sept. 30, 2009, and 2008, respectively. The valuations are based on a market input evaluation pricing methodology using a combination of market observable data such as current market trade data, reported bid/ask spreads, and institutional bid information. The weighted-average interest rate was 5.3 percent for the Energy Northwest CGS, Nuclear Project No. 1, and Nuclear Project No. 3 portion of outstanding nonfederal debt as of Sept. 30, 2009.

Under the Lease Financing Program, BPA consolidates four special purpose corporations, collectively referred to as NIFCs, that issue debt to and receive advances from nonfederal sources. Combined, the NIFCs have issued $119.6 million in bonds and borrowed $325.5 million on lines of credit with various banks. The bonds bear interest at 5.4 percent per annum and mature in 2034. The lines of credit become due in full at various dates ranging between July 1, 2014, and Jan. 1, 2016. On the accompanying Combined Balance Sheets, the bonds and bank credit facilities are included in Nonfederal debt and the leased assets are included in Utility plant.

The fair value of the combined NIFC bonds and lines of credit exceeded the recorded value by $2.9 million as of Sept. 30, 2009, and was less than the recorded value by $32.0 million as of Sept. 30, 2008. The valuations are based on the discounted future cash flows using interest rates for similar debt which could have been issued at Sept. 30, 2009, and 2008, respectively. The weighted-average interest rate was 4.6 percent on the NIFCs' outstanding debt as of Sept. 30, 2009.

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

The Northern Wasco Hydro Project agreement was terminated by the Settlement and Termination Agreement between BPA and the Northern Wasco PUD on April 25, 1995. The Settlement Agreement requires BPA to pay the trustee annual debt service as required by the Bond Resolution.

Nonfederal debt includes both operating and nonoperating projects. BPA recognizes expenses for these projects based upon total project cash funding requirements, which include debt service and operating and maintenance expenses. BPA recognized operating and maintenance expense for these projects of $298.0 million, $248.9 million and $289.6 million in fiscal years 2009, 2008 and 2007, respectively, which is included in Operations and maintenance in the accompanying Combined Statements of Revenues and Expenses. Debt service for the projects of $501.4 million, $479.5 million and $343.3 million for fiscal years 2009, 2008 and 2007, respectively, is reflected as Nonfederal projects in the accompanying Combined Statements of Revenues and Expenses.

Nonfederal Debt

MATURING DEBT

As of Sept. 30 — thousands of dollars

2010	$ 319,980
2011	307,070
2012	466,130
2013	561,970
2014	742,166
2015 and thereafter	4,167,618
	$ 6,564,934

1989 Letter Agreement

In 1989 BPA 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.

9. Deferred credits

As of Sept. 30 — thousands of dollars

	2009	2008
Customer reimbursable projects	**$ 218,351**	$ 209,367
Generation interconnection agreements	**208,315**	159,100
Third AC Intertie capacity agreements	**106,490**	107,285
Derivative instruments	**42,764**	15,486
Fiber optic leasing fees	**38,916**	42,594
Federal Employees' Compensation Act	**34,341**	34,478
Settlements	**28,500**	28,500
Capital leases	**17,900**	18,461
Other	**7,649**	9,021
Direct-service industries' benefits	**—**	173,207
	$ 703,226	$ 797,499

Deferred credits include the following items:

- "Customer reimbursable projects" consist of advances received from customers where either the customer or BPA will own the resulting asset. If the customer will own the asset under construction, the revenue is recognized as the expenditures are incurred. If BPA will own the resulting asset, the revenue is recognized over the life of the asset once the corresponding asset is placed in service.
- "Generation interconnection agreements" are generators' advances held as security for requested new network upgrades and interconnection. These advances accrue interest and will be returned as credits against future transmission service on the new or upgraded lines.
- "Third AC Intertie capacity agreements" reflect unearned revenue from customers related to the Third AC Intertie capacity project. Revenue is being recognized over an estimated 49-year life of the related assets.
- "Derivative instruments" reflect the unrealized fair value loss of the derivative portfolio which includes physical power purchase and sale transactions and interest rate swap transactions.
- "Fiber optic leasing fees" reflect unearned revenue related to the leasing of the fiber optic cable. Revenue is being recognized over the lease terms extending out to 2020.
- "Federal Employees' Compensation Act" reflects the actuarial estimated amount of future payments for current recipients of BPA's worker compensation benefits.
- "Settlements" reflect an amount due for a settlement agreement resulting from litigation (see Note 12, Commitments and Contingencies).
- "Capital leases" represent BPA's long-term portion of capital lease liabilities for Goshen-Drummond and Lower Valley-Teton transmission lines.
- "Direct-service industries' benefits" were expected DSI payments to be made in the future and included in rates. In fiscal year 2009 the liabilities associated with this program were eliminated as the agreements giving rise to these liabilities were invalidated by the Ninth Circuit Court.

10. Risk management and derivative instruments

BPA is exposed to various forms of market risk including commodity price risk, commodity volumetric risk, interest rate risk, credit risk and event risk. Non-performance risk, which includes credit risk, is described in Note 11, Fair Value Measurements. BPA has formalized risk management processes in place to manage agency risks, including the use of derivative instruments. The following describes BPA's exposure to and management of risks.

RISK MANAGEMENT

Due to the operational risk posed by fluctuations in river flows and electric market prices, net revenues that result from underlying surplus or deficit energy positions are inherently uncertain. BPA's Transacting Risk Management Committee has responsibility for the oversight of market risk and determines the transactional risk policy and control environment at BPA. Through simulation and analysis of the hydro supply system, experienced business and risk managers install market price risk measures to capture additional market-related risks, including credit and event risk.

COMMODITY PRICE RISK AND VOLUMETRIC RISK

Primarily due to the variation in the available energy from its hydroelectric generation capacity, BPA enters into short- and long-term forward sales and purchase agreements in the wholesale markets to balance its energy supply and demand. Commodity price risk results from fluctuations in the electric market prices in the Pacific Northwest that affects the value of the energy inventory bought and sold as well as the value of prior purchase and sale contracts. In fiscal year 2009, there was a net surplus and sale of energy above that needed to serve the region's firm load obligations.

BPA measures the market price risk in its portfolio on a daily, weekly and monthly basis employing both parametric calculations and non-parametric Monte Carlo simulations to derive net revenues at risk, mark-to-market, value at risk, and additional risk metrics as appropriate. These methods provide a consistent measure of risk across the energy market in which BPA buys and sells. The use of these methods requires a number of key assumptions including hydro/price correlations, the selection of a confidence level for expected losses, the holding period for liquidation and the treatment of risks outside standard measures such as sensitivity and scenario testing to determine the impacts of a sudden change in market price, volatility, correlations or hydro inventory. These methods assume hypothetical movements in future market prices and in hydro inventory and provide an estimate of possible net revenues outcomes for BPA's portfolios. In response to market price risk, futures, forwards, swaps and option instruments may be used to mitigate BPA's exposure to price fluctuations.

BPA's principal market activity is for the sale of surplus inventory and power purchases to manage its load/resource balance rather than the purchase and sale of electricity to earn trading revenues. The tests critical to trading organizations (i.e., amount of risk to carry over very short time frames) are considered less important than regular and rigorous analysis of the consequences of a range of hydro supply conditions and prolonged holding periods.

CREDIT RISK

Credit risk relates to the risk of loss that might occur as a result of non-performance by counterparties of their obligations to deliver or take delivery of electricity. BPA's counterparties are generally large and stable and do not represent a significant concentration of credit risk. Credit risk is mitigated at BPA by reviewing counterparties for creditworthiness, establishing credit limits, and monitoring credit exposure on a daily basis. To further manage credit risk, BPA obtains credit support such as letters of credit, parental guarantees, cash in the form of prepayment, and deposit of escrow from some counterparties. Counterparties are monitored closely for changes in financial condition and credit reviews are updated regularly. BPA uses internally developed, commercially appropriate rating methodologies, credit scoring models, publicly available information and external ratings from major credit rating agencies to determine the public rating equivalent grade of counterparties.

During fiscal year 2009, BPA experienced no significant losses as a result of any customer defaults or bankruptcy filings. At Sept. 30, 2009, BPA had $35.9 million in credit exposure to purchase and sale contracts taking into account netting rights and BPA's credit exposure, net of collateral, to sub-investment grade counterparties which was less than one percent of total outstanding credit exposures. The agency's top five credit exposures were $35.2 million, or 98 percent, of the total credit exposure. The majority of this exposure is mark-to-market exposure arising from a term transaction with an "A+" rated municipality with ratemaking authority.

INTEREST RATE RISK

BPA has the ability to issue variable rate debt to the U.S. Treasury; however at Sept. 30, 2009, BPA has no federal variable debt outstanding. BPA is not exposed to substantial risk resulting from changes in interest rates as a result of its backing of the variable rate debt issued by Energy Northwest. All of the $400 million of Energy Northwest variable rate debt outstanding at Sept. 30, 2009, has been effectively swapped into fixed rate debt as described below in the following Interest Rate Swap Transactions section. Under these swap agreements, BPA pays the counterparties a fixed rate and receives a variable rate that is 68 percent of the LIBOR index rate. Although not a perfect match, the amount BPA receives is intended to offset the variable rate paid on the $400 million in bonds issued by Energy Northwest.

DERIVATIVE INSTRUMENTS

BPA follows the Derivatives and Hedging accounting guidance that requires every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and also requires that a change in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

COMMODITY CONTRACTS

It is BPA's policy to document and apply as appropriate the normal purchase and normal sales exception allowed under Derivatives and Hedging accounting guidance. Purchases and sales of forward electricity contracts are generally considered normal purchases and normal sales if they require physical delivery, are expected to be used or sold by BPA in the normal course of business and meet the definition of capacity described in the Derivatives and Hedging accounting guidance. These transactions are not required to be recorded at fair value in the financial statements. Recognition of these contracts in Sales or Purchased power in the Combined Statements of Revenues and Expenses occurs when the contracts settle.

For all other derivative transactions, BPA applies Fair Value Measurements and Disclosures accounting guidance and records the changes in fair value under Derivative instruments in the current period in the Combined Statements of Revenues and Expenses. When available, quoted market prices or prices obtained through external sources are used to measure a contract's fair value. For contracts without available quoted market prices, fair value is determined based on internally developed modeled prices (see Note 11, Fair Value Measurements).

BPA records realized and unrealized losses in the Combined Statements of Revenues and Expenses related to its derivative portfolio. At Sept. 30, 2009, the commodity contracts totaled 6.1 million MWh (gross basis). In the Combined Statements of Cash Flows, BPA records realized and unrealized gains and losses on commodity contract derivative transactions in the operating section. BPA does not apply hedge accounting.

INTEREST RATE SWAP TRANSACTIONS

BPA has 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 $199 million notional amount for 10 years and receives a variable rate that changes weekly tied to LIBOR. This swap transaction terminates in 2013. 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. This swap transaction terminates in 2018.

The net effect of the two swap transactions essentially replaces variable rate debt with 3.3 percent fixed rate debt. Interest rate swap expense is included in the cash paid for Nonfederal debt in the Combined Statements of Cash Flows. BPA records unrealized gains and losses on interest rate swap derivative transactions in the operating section as noncash adjustments to Net revenue in the Combined Statements of Cash Flows.

The following table presents BPA's derivative assets and liabilities measured at fair value.

DERIVATIVE ASSETS AND LIABILITIES MEASURED AT FAIR VALUE

As of Sept. 30 — thousands of dollars

	2009	2008
ASSETS		
Derivative instruments[1]		
Commodity contracts	**$ 33,549**	$ 43,709
Total (Gross)	**33,549**	43,709
less: netting [2]	**(1,343)**	(2,746)
Total (Net)	**$ 32,206**	$ 40,963
LIABILITIES		
Derivative instruments[1]		
Commodity contracts	**$ (12,861)**	$ (5,667)
Interest rate swaps	**(31,246)**	(12,565)
Total (Gross)	**(44,107)**	(18,232)
less: netting [2]	**1,343**	2,746
Total (Net)	**$(42,764)**	$(15,486)

[1] Derivative instruments assets and liabilities are included in Deferred charges and other and Deferred credits in the Combined Balance Sheets, respectively (see Note 5, Deferred Charges and Other and Note 9, Deferred Credits).

[2] Netting represents a balance sheet adjustment for same counterparty master netting arrangements.

The following table presents the effect of derivative instruments on the Combined Statements of Revenues and Expenses.

AMOUNT OF GAIN (LOSS) RECOGNIZED

As of Sept. 30 — thousands of dollars

	Location of Gain (Loss) Recognized in Net Revenues (Expenses)	2009	2008	2007
Commodity contracts	Derivative instruments	**$ (17,356)**	$ (13,314)	$ (4,402)
Interest rate swaps	Derivative instruments	**(18,680)**	(17,221)	(2,239)
	Nonfederal projects	**(7,450)**	—	—
Total		**$ (43,486)**	$ (30,535)	$ (6,641)

11. Fair Value Measurements

As described in Note 1, Summary of Significant Accounting Policies, BPA adopted the new Fair Value Measurements and Disclosures accounting guidance for all financial instruments (recurring and nonrecurring) and for all nonfinancial instruments subject to recurring fair value measurement effective Oct. 1, 2008. This accounting guidance defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value measurements. This accounting guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. This accounting guidance clarifies that fair value should be based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of counterparties involved and the impact of credit enhancements but also the impact of BPA's own non-performance risk on its liabilities.

The Fair Value Measurements and Disclosures accounting guidance also requires fair value measurements to assume that the transaction occurs in the principal market for the asset or liability (the market with the most volume and activity for the asset or liability from the perspective of the reporting entity), or in the absence of a principal market, the most advantageous market for the asset or liability (the market in which the reporting entity would be able to maximize the amount received or minimize the amount paid). BPA applied fair value measurements to certain assets and liabilities including commodity and interest rate derivative instruments and nuclear decommissioning trust and other investments in accordance with the requirements described above.

In accordance with the Fair Value Measurements and Disclosures accounting guidance, BPA maximizes the use of observable inputs and minimizes the use of unobservable inputs when measuring fair value.

Fair value is based on actively quoted market prices, if available. In the absence of actively quoted market prices, BPA seeks price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, BPA uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs.

The non-exchange-based option contracts are measured at fair value using models or other market accepted methodologies derived from observable market data and unobservable inputs. These models are primarily industry standard models that consider various inputs including: a) quoted forward prices for commodities, b) time value, c) volatility factors, d) current market and contractual prices for underlying instruments and e) market interest rates and yield curves as well as other relevant economic measures.

BPA also utilizes the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value, into three broad levels:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets and liabilities that BPA has the ability to access at the measurement date. Instruments categorized in Level 1 primarily consist of financial instruments such as fixed income, equity mutual funds and money market funds.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include certain non-exchange traded derivatives, certain agency securities as part of the special purpose corporations' trust funds investments and interest rate swaps.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 include long-dated and modeled commodity contracts.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

In accordance with the Fair Value Measurements and Disclosures accounting guidance, BPA includes non-performance risk in calculating fair value measurements. This includes a credit risk adjustment based on the credit spreads of BPA's counterparties when in an unrealized gain position, or on BPA's own credit spread when in an unrealized loss position. BPA's assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at Sept. 30, 2009.

The Fair Value Measurements and Disclosures accounting guidance requires fair value measurements to be separately disclosed by level within the fair value hierarchy and requires a separate reconciliation of fair value measurements categorized as Level 3. The following table presents for each hierarchy level BPA's assets and liabilities measured at fair value on a recurring basis, as of Sept. 30, 2009.

70

Assets and liabilities measured at fair value on a recurring basis

As of Sept. 30 — thousands of dollars

	Level 1	Level 2	Level 3	Netting[2]	Total
ASSETS					
Nonfederal nuclear decommissioning trusts	$ 167,232	$ —	$ —	$ —	**$167,232**
Derivative instruments[1]					
Commodity contracts	—	5,359	28,190	(1,343)	**32,206**
Special purpose corporations' trust funds	24,423	103,500	—	—	**127,923**
Total	$191,655	$108,859	$28,190	$(1,343)	$327,361
LIABILITIES					
Derivative instruments[1]					
Commodity contracts	$ —	$ (12,861)	$ —	$ 1,343	**$(11,518)**
Interest rate swaps	—	(31,246)	—	—	**(31,246)**
Total	$ —	$(44,107)	$ —	$ 1,343	$(42,764)

[1] Derivative instruments assets and liabilities are included in Deferred charges and other and Deferred credits in the Combined Balance Sheets, respectively (see Note 5, Deferred Charges and Other and Note 9, Deferred Credits). See Note 10, Risk Management and Derivative Instruments for more information related to BPA's risk strategy and use of derivative instruments.

[2] Netting represents a balance sheet adjustment for same counterparty master netting arrangements.

The following table presents the changes in the assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category for the fiscal year ended Sept. 30, 2009.

Thousands of dollars

	COMMODITY CONTRACTS
Balance at Sept. 30, 2008	$ 38,486
Total realized and unrealized gains (losses) included in Net revenues (expenses)[1]	(10,296)
Purchases, issuance and settlements	–
Transfers in (out) of Level 3	–
Balance at Sept. 30, 2009	**$ 28,190**
The amount of total gains (losses) for the fiscal year included in Net revenues (expenses) attributable to the change in unrealized gains (losses) relating to contracts still held at the reporting date[1]	**$ (8,966)**

[1] Level – 3 category unrealized losses are included in Derivative instruments and realized losses are included in Purchase power in the Combined Statement of Revenues and Expenses for the fiscal year ended Sept. 30, 2009.

12. Commitments and contingencies

FIRM PURCHASE POWER AND COMMITMENTS

As of Sept. 30 — thousands of dollars

2010	$ 84,566
2011	70,692
2012	83,805
2013	75,898
2014	78,756
2015 and thereafter	602,970
	$996,687

BPA enters into commitments to sell expected generation for future dates and when BPA forecasts a resource shortage, BPA plans to take necessary steps to cover the shortage, including, if appropriate, commitments to purchase power for future dates. BPA records expenses associated with these purchases in the periods that power is received.

ENDANGERED SPECIES ACT

The Northwest Power Act directs BPA 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. BPA makes expenditures and incurs other costs for fish and wildlife consistent with the Northwest Power Act and the Pacific Northwest Power and Conservation Council's Columbia River Basin Fish and Wildlife Program.

Additionally, certain fish species under the Endangered Species Act (ESA) are listed as threatened or endangered. BPA is financially responsible for expenditures and other costs arising from conformance with the ESA and certain biological opinions prepared by the National Oceanic and Atmospheric Administration Fisheries Service and the U.S. Fish and Wildlife Service in furtherance of the ESA.

In May 2008 BPA, Corps and Reclamation signed 10-year agreements with four Northwest tribes, the Columbia River Inter-Tribal Fish Commission (CRITFC), the State of Idaho and the State of Montana. The Shoshone-Bannock Tribes signed their agreement on Nov. 7, 2008. These agreements that are collectively referred to as the Columbia Basin Fish Accords (Fish Accords) provide for BPA to fund up to approximately $994.0 million over 10 years, enabling the tribes and states to continue existing programs and to implement new priority fish projects.

In early 2009, Judge Redden requested the Obama administration to present a position on the Biological Opinion (BiOp). The administration has concluded that with an Adaptive Management Implementation Plan (AMIP), the BiOp is biologically and legally sound. The AMIP enhances the BiOp's existing adaptive management framework by employing a more precautionary approach. This means that if ESA-listed salmon and steelhead runs unexpectedly go into significant decline, then certain specified procedures and actions are ready to address the problem.

On Sept. 16, 2009, BPA, Corps and Reclamation signed an agreement with the State of Washington to provide funds to improve the Columbia River estuary habitat. This agreement adds $40.5 million to the $49.5 million the BiOp already dedicates for a total commitment of $90.0 million for estuary habitat through 2018.

BPA's first new rates, since the BiOp and Fish Accords, went into effect Oct. 1, 2009. These rates include an additional $103.9 million for funding the new activities identified in the BiOp and Fish Accords. The costs of implementing the BiOp's new contingency actions if fish runs experience a severe decline have not been estimated. The State of Oregon, the Nez Perce Tribe and a coalition of environmental and fishing groups filed a response to the AMIP in the U.S. District Court on Oct. 7, 2009. The government filed a rebuttal on Oct. 23, 2009.

Based on the agreements above, BPA has approximately $1.1 billion in total commitments.

Irrigation assistance

SCHEDULED DISTRIBUTIONS

As of Sept. 30 — thousands of dollars

2010	$ —
2011	—
2012	1,182
2013	58,822
2014	52,426
2015 and thereafter	553,791
	$ 666,221

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. Future irrigation assistance payments ultimately could total $666.2 million and are scheduled over a maximum of 66 years since the time the irrigation facilities were completed and placed in service. 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 to the extent the costs have been determined to be beyond the irrigators' ability to repay. These requirements are met by conducting power repayment studies including schedules of distributions at the proposed rates to demonstrate repayment of principal within the allowable repayment period. Irrigation assistance excludes $40.3 million for Teton Dam which failed prior to completion and for which BPA has no obligation to recover these costs.

Additional post-retirement contributions – future contributions

As of Sept. 30 — thousands of dollars

2010	$ 33,435
2011	33,560
2012	34,486
2013	35,641
2014	37,002
	$ 174,124

All fiscal years are estimates and subject to change.

BPA makes additional annual contributions to the U.S. Treasury in order to ensure that all federal post-retirement benefit programs provided to federal employees associated with the operation of the FCRPS are fully funded and to ensure that 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 underfunded. BPA paid $32.7 million, $18.0 million and $21.1 million to the U.S. Treasury during fiscal years 2009, 2008 and 2007, respectively. BPA records these amounts as expenses during the year in which they are paid.

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 $6.9 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $14.4 million. For the Business Interruption and/or Extra Expense Insurance policy, the maximum assessment is $4.8 million.

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

ENVIRONMENTAL MATTERS

From time to time there are sites for which BPA, Corps or Reclamation may be identified as potential responsible parties. Costs associated with cleanup of sites are not expected to be material to the FCRPS' financial statements. As such, no liability has been recorded.

LITIGATION

Southern California Edison

Southern California Edison (SCE) filed two separate actions pending in the U.S. Court of Federal Claims against BPA related to a power sales and exchange agreement (Sale and Exchange Agreement) between BPA and SCE. The actions challenged: 1) BPA's decision to convert the contract from a sale of power to an exchange of power as provided for under the terms of the contract (Conversion Claim); and 2) BPA's termination of the Sales and Exchange Agreement due to SCE's nonperformance (Termination Claim).

In 2006, BPA and SCE executed an agreement to settle the claims wherein BPA would make a payment of $28.5 million plus applicable interest to SCE if certain identified conditions were met, including a final resolution of BPA's claims pending in the California refund proceedings and related litigation. BPA has recorded a liability in this amount on the basis that all conditions have been met except the final resolution in the California refund proceedings which management considers probable.

BPA established an offsetting regulatory asset for the liability as the costs will be collected in future rates.

California parties' refund claims

BPA was a party to proceedings at FERC that sought refunds for sales into markets operated by the California Independent System Operator (ISO) and the California Power Exchange (PX) during the California energy crisis of 2000-2001. BPA along with a number of other governmental utilities challenged the Commission's refund authority over governmental utilities. In BPA v. FERC, 422 F.3d 908 (9th Cir. 2005) the Court found that governmental utilities, like BPA, were not subject to FERC's statutory refund authority. As a consequence of the Court's decision, three California investor-owned utilities along with the State of California filed breach of contract claims in the United States Court of Federal Claims against BPA. The complaints, filed in March of 2007, alleged that BPA was contractually obligated to pay refunds on transactions where BPA received amounts in excess of mitigated market clearing prices established by FERC. The plaintiffs' contractual breach is premised upon a Commission finding that it retroactively reset the prices under the ISO and PX tariffs when it established these mitigated market clearing prices. BPA has separately appealed to the Ninth Circuit Court the Commission finding that it retroactively reset the tariff prices. The plaintiffs' claims for relief exceed $300 million.

Rates

BPA's rates are frequently the subject of litigation. Most of the litigation involves claims that BPA's rates are inconsistent with statutory directives, are not supported by substantial evidence in the record, or are arbitrary and capricious. It is the opinion of BPA's General Counsel that if any rate were to be rejected, the sole remedy accorded would be a remand to BPA to establish a new rate. BPA's flexibility in establishing rates could be restricted by the rejection of a BPA rate, depending on the grounds for the rejection. BPA is unable to predict, however, what new rate it would establish if a rate were rejected. If BPA were to establish a rate that was lower than the rejected rate, a petitioner may be entitled to a refund in the amount overpaid; however, BPA is required by law to set rates to meet all of its costs. Thus, it is the opinion of BPA's General Counsel that BPA may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Currently pending before the Ninth Circuit Court are numerous challenges to the decisions BPA reached in the WP-07 Supplemental Rate Case. The petitioners in these cases challenge, among other issues, BPA's calculation of the Lookback Amounts, BPA's decision to recover the Lookback Amounts and BPA's determination of REP benefits. While it is possible that such challenges could result in changes to BPA's calculation or recovery of the Lookback Amounts, BPA management believes any changes would be resolved through future rates.

Other

The FCRPS may be affected by various other legal claims, actions and complaints, including litigation under the Endangered Species Act, which may include BPA as a named party. Certain of these cases may involve material amounts. BPA is unable to predict whether the FCRPS will avoid adverse outcomes in these legal proceedings or, if not, what the impact might be. BPA currently believes that disposition of pending matters will not have a materially adverse effect on the FCRPS' financial position or results of operations for fiscal year 2009.

Judgments and settlements are included in BPA's costs and recovered through rates. Except with respect to the SCE matter described above, BPA management has not recorded a liability for the above legal matters.

Appendix B-2

Federal Columbia River Power System
Combined Balance Sheets
(Unaudited)

	Dec. 31, 2009	Sept. 30, 2009
	(thousands of dollars)	
Assets		
Utility plant		
Completed plant	**$ 13,901,769**	$ 13,883,626
Accumulated depreciation	**(5,143,845)**	(5,106,884)
	8,757,924	8,776,742
Construction work in progress	**1,105,369**	985,624
Net utility plant	**9,863,293**	9,762,366
Nonfederal generation	**2,514,885**	2,520,245
Current assets		
Cash	**1,360,740**	1,357,019
U.S. Treasury market-based special securities	**63,921**	14,554
Accounts receivable, net of allowance	**100,624**	112,251
Accrued unbilled revenues	**265,986**	172,842
Materials and supplies, at average cost	**82,540**	77,612
Prepaid expenses	**28,171**	24,652
Total current assets	**1,901,982**	1,758,930
Other assets		
Regulatory assets	**5,088,851**	5,112,346
U.S. Treasury market-based special securities	**131,536**	83,041
Nonfederal nuclear decommissioning trusts	**172,692**	167,232
Deferred charges and other	**225,261**	235,119
Total other assets	**5,618,340**	5,597,738
Total assets	**$ 19,898,500**	$ 19,639,279
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 2,612,497**	$ 2,556,272
Federal appropriations	**4,414,642**	4,392,405
Borrowings from U.S. Treasury	**1,949,440**	1,765,440
Nonfederal debt	**6,234,289**	6,244,954
Total capitalization and long-term liabilities	**15,210,868**	14,959,071
Commitments and contingencies (See Note 12 to annual financial statements)		
Current liabilities		
Federal appropriations	**3,784**	3,784
Borrowings from U.S. Treasury	**365,000**	365,000
Nonfederal debt	**320,465**	319,980
Accounts payable and other	**506,360**	474,349
Total current liabilities	**1,195,609**	1,163,113
Other Liabilities		
Regulatory liabilities	**2,544,378**	2,567,271
IOU exchange benefits	**83,995**	83,655
Asset retirement obligations	**164,770**	162,943
Deferred credits	**698,880**	703,226
Total other liabilities	**3,492,023**	3,517,095
Total capitalization and liabilities	**$ 19,898,500**	$ 19,639,279

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

	Three Months Ended Dec. 31,		Fiscal Year-to-Date Ended Dec. 31,	
	2009	2008	**2009**	2008
		(thousands of dollars)		
Operating revenues				
Sales	**$ 767,035**	$ 726,519	**$ 767,035**	$ 726,519
Derivative instruments	**(8,599)**	(39,947)	**(8,599)**	(39,947)
U.S. Treasury credits for fish	**23,743**	21,589	**23,743**	21,589
Miscellaneous revenues	**15,294**	14,932	**15,294**	14,932
Total operating revenues	**797,473**	723,093	**797,473**	723,093
Operating expenses				
Operations and maintenance	**352,884**	350,190	**352,884**	350,190
Purchased power	**89,679**	123,390	**89,679**	123,390
Nonfederal projects	**150,852**	123,952	**150,852**	123,952
Depreciation and amortization	**89,859**	88,000	**89,859**	88,000
Total operating expenses	**683,274**	685,532	**683,274**	685,532
Net operating revenues	**114,199**	37,561	**114,199**	37,561
Interest expense and (income)				
Interest expense	**81,771**	81,312	**81,771**	81,312
Allowance for funds used during construction	**(10,141)**	(8,143)	**(10,141)**	(8,143)
Interest income	**(13,656)**	(18,962)	**(13,656)**	(18,962)
Net interest expense	**57,974**	54,207	**57,974**	54,207
Net revenues (expenses)	**$ 56,225**	$ (16,646)	**$ 56,225**	$ (16,646)

Federal Columbia River Power System
Combined Statements of Cash Flows
(Unaudited)

	Fiscal Year-to-Date Ended Dec. 31, 2009	2008
	(thousands of dollars)	
Cash provided by and (used) for operating activities		
Net revenues	**$ 56,225**	$ (16,646)
Non-cash items:		
Depreciation and amortization	**89,859**	88,000
Unrealized loss on derivative instruments	**9,285**	39,976
Changes in:		
Receivables and unbilled revenues	**(79,378)**	(53,975)
Materials and supplies	**(4,928)**	(2,046)
Prepaid expenses	**(3,519)**	1,847
Accounts payable and other	**9,058**	(108,635)
Regulatory assets and liabilities	**(17,939)**	(4,991)
Other assets and liabilities	**(15,112)**	5,729
Cash provided by (used for) operating activities	**43,551**	(50,741)
Cash provided by and (used) for investing activities		
Investment in:		
Utility plant (including AFUDC)	**(146,992)**	(83,568)
Nonfederal generation	**5,360**	5,110
U.S. Treasury market-based special securities:		
Purchases	**(100,000)**	(100,000)
Maturities	**-**	-
Nonfederal nuclear decommissioning trusts	**(2,012)**	(1,962)
Special purpose corporations' trust funds:		
Deposits to	**-**	(23,199)
Receipts from	**1,953**	25,327
Cash used for investing activities	**(241,691)**	(178,292)
Cash provided by and (used) for financing activities		
Federal construction appropriations:		
Increase	**22,236**	16,564
Repayment	**-**	-
Borrowings from U.S. Treasury:		
Increase	**184,000**	-
Repayment	**-**	(35,000)
Nonfederal debt:		
Increase	**-**	23,199
Repayment	**(10,180)**	(9,715)
Customers:		
Advances for construction	**16,608**	27,934
Reimbursements to customers	**(10,803)**	(4,085)
Cash provided by financing activities	**201,861**	18,897
Increase (decrease) in cash	**3,721**	(210,136)
Beginning cash balance	**1,357,019**	1,731,238
Ending cash balance	**$ 1,360,740**	$ 1,521,102
Cash paid for interest, net of U.S. Treasury credits	**$ 5,581**	$ 2,491
Supplemental schedule of noncash operating activities:		
Interest credits	**$ 12,429**	$ 16,982
U. S. Treasury credits	**$ -**	$ -

REPORT OF INDEPENDENT AUDITORS

To the Executive Board of Energy Northwest

In our opinion, the financial statements of the business-type activities of Energy Northwest (the "Company"), including the Columbia Generating Station, Packwood Lake Hydroelectric Project, Nuclear Project No. 1, Nuclear Project No. 3, the Business Development Fund, the Nine Canyon Wind Project, and the Internal Service Fund which collectively comprise the Company's balance sheets, statements of revenues, expenses and changes in net assets, and of cash flows, present fairly, in all material respects, the respective financial position of the business-type activities of the Company at June 30, 2009, and the respective changes in financial position and cash flows, where applicable, thereof for the year then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express opinions on these financial statements based on our audit. We conducted our audit 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 audit provides a reasonable basis for our opinions.

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

PricewaterhouseCoopers LLP

Portland, Oregon
September 24, 2009

Energy Northwest Management's Discussion and Analysis

Energy Northwest is a municipal corporation and joint operating agency of the State of Washington. Each Energy Northwest business unit is financed and accounted for separately from all other current or future business assets. The following discussion and analysis is organized by business unit. The management discussion and analysis of the financial performance and activity is provided as an introduction and to aid in comparing the basic financial statements for the Fiscal Year (FY) ended June 30, 2009, with the basic financial statements for the FY ended June 30, 2008.

Energy Northwest has adopted accounting policies and principles that are in accordance with Generally Accepted Accounting Principles (GAAP) in the United States of America. Energy Northwest's records are maintained as prescribed by the Governmental Accounting Standards Board (GASB) and, when not in conflict with GASB pronouncements, accounting principles prescribed by the Financial Accounting Standards Board (FASB). (See Note 1 to the Financial Statements.)

Because each business unit is financed and accounted for separately, the following section on financial performance is discussed by business unit to aid in analysis of assessing the financial position of each individual business unit. For comparative purposes only, the table on the following page represents a memorandum total only for Energy Northwest, as a whole, for FY 2009 and FY 2008 in accordance with GASB No. 34, "Basic Financial Statements-and Management's Discussion and Analysis-for State and Local Governments."

The financial statements for Energy Northwest include the Balance Sheets, Statements of Revenues, Expenses, and Changes in Net Assets, Statements of Cash Flows for each of the business units, and Notes to Financial Statements.

The Balance Sheets present the financial position of each business unit on an accrual basis. The Balance Sheets report financial information about construction work in progress, the amount of resources and obligations, restricted accounts and due to/from balances for each business unit. (See Note 1 to the Financial Statements.)

The Statements of Revenues, Expenses, and Changes in Net Assets provide financial 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 financial 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 the cash comes from, and purpose of cash activity.

The Notes to Financial Statements present disclosures that contribute to the understanding of the material presented in the financial statements. This includes, but is not limited to, Schedule of Outstanding Long-Term Debt and Debt Service Requirements (See Note 5 to the Financial Statements), accounting policies, significant balances and activities, material risks, commitments and obligations, and subsequent events, if applicable.

The basic financial statements of each business unit along with the notes to the financial statements and the management discussion and analysis should be used to provide an overview of Energy Northwest's financial performance. Questions concerning any of the information provided in this report should be addressed to Energy Northwest at PO Box 968, Richland, WA, 99352.

COMBINED FINANCIAL INFORMATION

JUNE 30, 2009 AND 2008 (000'S)

	2008	2009	Change
Assets			
Current Assets	$ 173,689	$ 187, 671	$ 13,982
Restricted Assets			
Special Funds	119,525	104,325	(15,200)
Debt Service Funds	298,820	279,241	(19,579)
Net Plant	1,509,814	1,497,182	(12,632)
Nuclear Fuel	208,082	222,927	14,845
Deferred Charges	4,492,382	4,455,067	(37,315)
TOTAL ASSETS	$ 6,802,312	$ 6,746,413	$ (55,899)
Current Liabilities	$ 247,918	$ 243,042	$ (4,876)
Restricted Liabilities			
Special Funds	128,678	135,373	6,695
Debt Service Funds	129,738	137,293	7,555
Long-Term Debt	6,290,766	6,226,186	(64,580)
Other Long-Term Liabilities	9,337	10,597	1,260
Deferred Credits	5,920	6,179	259
Net Assets	(10,045)	(12,257)	(2,212)
TOTAL LIABILITIES & NET ASSETS	$ 6,802,312	$ 6,746,413	$ (55,899)
Operating Revenues	$ 455,066	$ 545,775	$ 90,709
Operating Expenses	336,622	428,946	92,324
Net Operating Revenues	$ 118,444	$ 116,829	$ (1,615)
Other Income and Expense	$ (120,337)	$ (119,870)	$ 467
(Distribution)/Contribution	(485)	829	1,314
Beginning Fund Equity	(7,667)	(10,045)	(2,378)
ENDING NET ASSETS	$ (10,045)	$ (12,257)	$ 2,212

Columbia Generating Station

The Columbia Generating Station (Columbia) is wholly owned by Energy Northwest and its Participants and operated by Energy Northwest. The plant is a 1,150-megawatt electric (MWe, Design Electric Rating, net) boiling water nuclear power plant located on the Department of Energy's (DOE) Hanford Site north of Richland, Washington.

Columbia produced 7,725 gigawatt-hours (GWh) of electricity in FY 2009, as compared to 9,594 GWh of electricity in FY 2008, which included economic dispatch of 15 and 134 GWh respectively. Columbia completed its two-year refueling and maintenance outage (R-19) on June 24 (47 days), with costs totaling $116.7 million. Budgeted days and costs for R-19 were 38 days and $117.5 million.

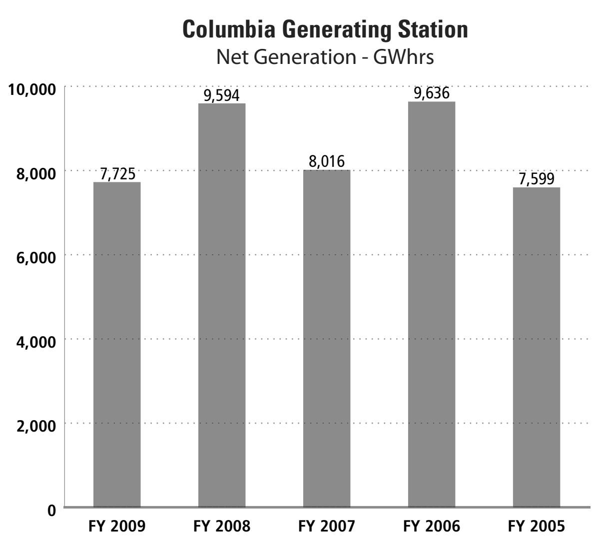
Generation was down 19.5 percent from FY 2008 due to the completion of R-19, two forced outages, (August 2008 and February 2009), a down-power to 60% for one week in April 2009 to allow for feed water pump work, maintenance outage in November 2008 and FY 2008 being the second best generation year on record.

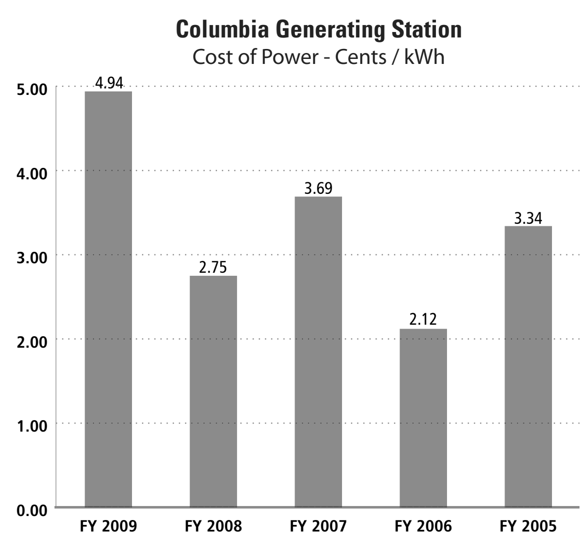
Columbia's performance is measured in several ways, including cost of power at Columbia. The cost of power for FY 2009 was 4.94 cents per kilowatt-hour (kWh) as compared with 2.75 cents per kWh in FY 2008. The industry cost of power fluctuates year to year depending on various factors such as refueling outages and other planned activities. Lower generation figures due to R-19, two forced outages, down-power constraints and the maintenance outage were the major drivers for the 79.6 percent increase in cost of power.

BALANCE SHEET ANALYSIS

The net decrease to Plant in Service (Plant) and Construction Work In Progress (CWIP) from FY 2008 to FY 2009 (excluding nuclear fuel) was $5.0 million. The additions to Plant/CWIP of $70.0 million were offset by an increase to Accumulated Depreciation of $75.0 million resulting in the net decrease to Plant. The additions to Plant for FY 2009 were captured in seven major projects: Main Condenser Replacement, Reactor Recirculation Motor Refurbishment, Radio Obsolescence, Software Programs, Reactor Feed Pump Control Systems, Fatigue Order Tracking System, and the Cobalt Reduction Program. These projects resulted in 74 percent of the additions to Plant. The remaining 26 percent of additions were made up of 158 separate projects.

Nuclear fuel, net of accumulated amortization, increased $14.8 million from FY 2008 to $222.9 million for FY 2009. During FY 2009 Columbia incurred $38.8 million in capitalized fuel





purchases. Fuel bundles of $19.0 million were inserted in cycle 20 during R-19 and $18.0 million of uranium will be used for future reloads in cycle 21 and beyond. The fuel activity was offset by $24.0 million in current year amortization.

Current assets increased $4.2 million in FY 2009 to $139.1 million. The main cause of this increase was from vendor invoice timing related to year end obligations incurred which amounted to approximately $8.0 million. The remaining difference was due to a decrease in materials and supplies of $3.8 million.

The Restricted Assets Special Funds decreased $5.8 million to $85.2 million in FY 2009 due to the FY 2009 bond financing plan and schedule of construction costs for these funds in FY 2009.

The Debt Service Funds increased $22.9 million in FY 2009 to $80.9 million. The increase was created due to restructuring as a result of the bond sale.

Deferred Charges increased $44.1 million in FY 2009 from $809.2 million to $853.3 million. Components of this increase were an increase to Costs in Excess of Billings, related to refunding of current maturities of $41.7 million and a slight decrease to unamortized debt expense of $0.5 million and an increase of $2.9 million for relicensing efforts. 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 12 to the Financial Statements.) The balances in these external trust funds are not reflected on Energy Northwest's Balance Sheet. Relicensing activities for Columbia accounted for $2.9 million of the increase. Columbia was issued a standard 40-year operating license by the Nuclear Regulatory Commission (NRC) in 1983. Energy Northwest is preparing an application to renew the license for an additional 20 years, thus continuing operations to 2043. Submittal of this application is planned for January 2010. The estimated duration of the license renewal process is 20-24 months from acceptance of application.

Current Liabilities increased $25.3 million in FY 2009 to $87.3 million mostly due to current maturities of long-term debt and incurred costs at year end being higher than last year.

Restricted Liabilities (Special Funds and Debt Service) increased $11.3 million in FY 2009 to $191.1 due to bond activity.

Long-Term Debt increased $37.3 million in FY 2009 from $2.4 billion to $2.5 billion, excluding current maturities, which was a result of the FY 2009 bond Issue. In FY 2009, new debt was issued for various Columbia construction projects, as well as for part of the Debt Optimization Program. (See Note 5 to the Financial Statements.)

Other long-term liabilities increased $1.2 million in FY 2009 to $10.6 million related to nuclear fuel cask activity.

STATEMENT OF OPERATIONS ANALYSIS

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

Operating expenses increased $90.4 million from FY 2008 to $403.7 million due to activity associated with R-19 and other outage related occurrences. Operations and Maintenance costs increased $94.3 million as a result of outage activity. The $3.0 increase to Administrative and General Expense was due to staffing requirements, related benefit increases and increased regulatory expenses. There were increases to depreciation of $4.1 million due to plant increases and a slight increase of $0.3 million to decommissioning. The increases of $101.7 million were offset by decreases in nuclear fuel and disposal costs of $10.4

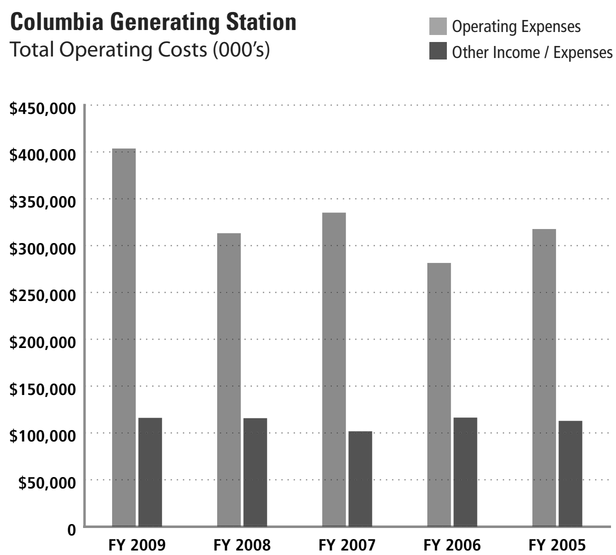
million and by a decrease to generation tax of $0.9 million. These decreases were directly related to lower generation activity.

Other Income and Expenses increased $0.3 million from FY 2008 to $116.1 million net expenses in FY 2009. Expenses associated with bond activity increased $2.5 million but were offset by lower investment income of $2.4 million, due to market conditions. The remaining increase was due to increased costs associated with inter-business unit services.

Columbia's total operating revenue increased from $429.0 million in FY 2008 to $519.8 million in FY 2009. The increase of $90.8 million was due to increased costs associated with R-19 and other outage activity and the related effects of the net billing agreements on total revenue.

Columbia incurred additional costs as a result of a FY 2008 (February) wind storm that damaged siding on the Reactor Building and Turbine Generator Building. The damage from the wind storm did not affect generation during the repair period. Approximately $5.3 million was incurred in FY 2008 for repair work and $8.7 million was incurred in FY 2009. Columbia submitted an insurance claim for reimbursement of the $14.0 million incurred due to wind damage. Columbia incurred costs of $5.0 million for the deductible and $7.7 million of the remaining amount was covered by the insurer, which was paid directly to BPA. An additional $7.5 million in costs are expected to be incurred in FY 2010 and will also be submitted for insurance reimbursement.

Columbia Generating Station
Total Operating Costs (000's)

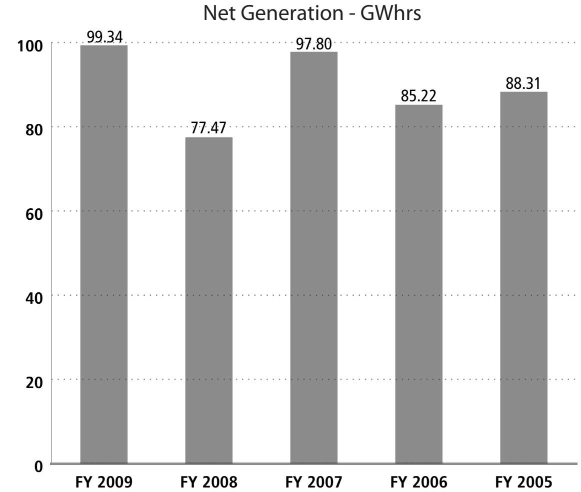


Packwood Lake Hydroelectric Project

The Packwood Lake Hydroelectric Project (Packwood) is wholly owned and operated by Energy Northwest. Packwood consists of a diversion structure at Packwood Lake and a powerhouse located near the town of Packwood, Washington. The water is carried from the lake to the powerhouse through a five-mile long buried tunnel and drops nearly 1,800 feet in elevation. Packwood produced 99.34 GWh of electricity in FY 2009 versus 77.47 GWh in FY 2008. The 28.2 percent increase in generation can be attributed to an excellent snowpack and ample water available for generation. FY 2008 experienced the lowest water levels in seven years while conditions in FY 2009 resulted in a 14.2 percent increase in generation above the 30 year average of 86.97 GWh and was the 12th highest generation year on record.

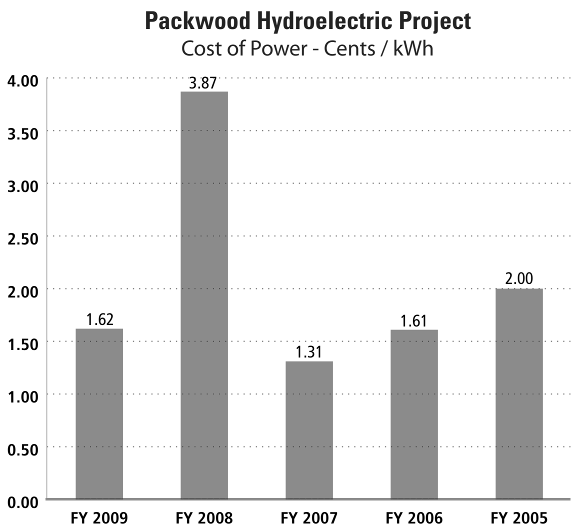
In November 2006, Lewis County was declared a disaster area because of torrential rain and flooding. During this event a large slide occurred adjacent to the Packwood underground pipeline. Significant repairs to stabilize the pipeline were completed during the following year. Expenditures of $1.0 million were incurred to install an H-Pile wall and improve drainage to mitigate the recurrence of additional slides in that area. Packwood applied for "Public Assistance Grants" from the Washington State Military Department (Emergency Management Division) and Federal Emergency Management Agency (FEMA) in FY 2007 and the acceptance remains in pending status. Due to the delay in grant acceptance a bank line

Packwood Hydroelectric Project
Net Generation - GWhrs



of credit was established for $1.3 million while grant acceptance from FEMA is being resolved. The line of credit has a $0.8 million outstanding balance.

Packwood's performance is measured in several ways, including cost of power. The cost of power for FY 2009 was $1.62 cents/kWh as compared to $3.87 cents/kWh in FY 2008. The cost of power fluctuates year-to-year depending on various factors such as outage, maintenance, generation, and other operating costs. The FY 2009 cost of power decrease was due to increased generation which resulted in an increase in secondary market sales.



BALANCE SHEET ANALYSIS

Total assets decreased $1.0 million from FY 2008, with the major driver being the decrease to restricted assets from $1.8 million to $0.8 million reflecting the elimination of all bonded debt associated with Packwood. The impact of debt elimination was offset by an increase to relicensing of $0.2 million and net participant and receivable activity of $0.2 million. Significant changes to total liabilities were a direct result of the elimination of all bonded debt for Packwood.

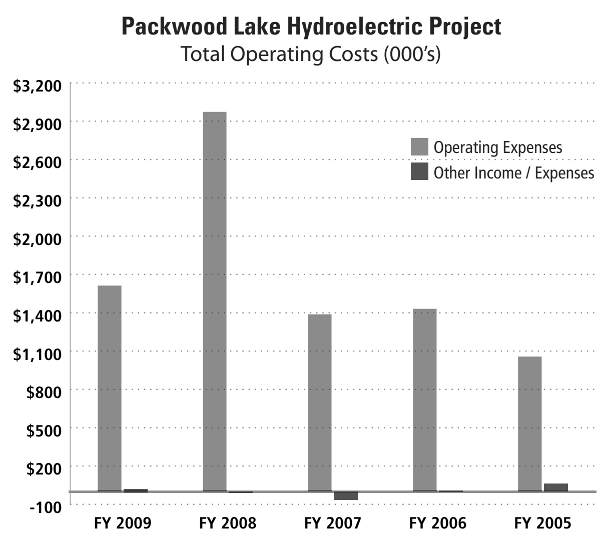
Packwood has incurred $3.6 million in relicensing costs through FY 2009. These costs are shown as Deferred Charges on the Balance Sheet. The FY 2010 projections call for an additional $0.5 million in costs to continue the relicensing efforts. The FERC issued a 50-year operating license to Packwood on March 1, 1960. The current license will expire on February 28, 2010. The final application for the relicensing of Packwood was submitted to FERC on February 22, 2008. The estimated license renewal process is 18-24 months from the acceptance of application.

STATEMENT OF OPERATIONS ANALYSIS

The agreement with Packwood participants obligates them to pay annual costs and to receive excess revenues. (See Note 1 to the Financial Statements.) Accordingly, Energy Northwest recognizes revenues equal to expenses for each period. No net revenue or loss is recognized and no equity is accumulated.

Operating expenses decreased $1.4 million from FY 2008 amounts, reflecting lower maintenance and outage costs and other power supply expenses. FY 2008 incurred additional costs for slide repair work of $0.9 million and purchased power costs of $0.7 million related to low water conditions. Slight increases in FY 2009 took place to depreciation of $1k for plant activity and generation tax of $4k due to increased generation.

Packwood is obligated to supply a specified amount of power hourly, known as Priority Firm Energy (PFE). The amount varies monthly based on historical average generation. If the project can not deliver PFE, replacement power must be purchased on the spot market. Electrical energy from Packwood is currently sold directly to Snohomish PUD who purchases all of the output directly. The power purchase agreement (PPA) provides a predetermined rate for all firm delivery, per the contract



schedule and the Mid-Columbia (Mid-C) based rate for any deliveries above firm, or secondary power. Conversely, if there is excess capacity per the PPA with Snohomish PUD, Energy Northwest sells the excess on the open market for additional revenues to be included as part of the PPA with the participants of the project. (See Note 6 to the Financial Statements.)

Other income and expenses decreased from a net income of $11k in FY 2008 to a net loss of $28k in FY 2009. The decrease in other income was due to much lower investment returns and decreased investment requirements due to bond retirement. Investment income decreased $66k from FY 2008 which was offset by a decrease to bond related expenses of $27k.

Nuclear Project No. 1

Energy Northwest wholly owns 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. All funding requirements are net-billed obligations of Nuclear Project No. 1. Termination expenses and debt service costs comprise the activity on Nuclear Project No. 1 and are net-billed.

BALANCE SHEET ANALYSIS

Long-term debt decreased $41.2 million from $1.926 billion in FY 2008 to $1.885 billion in FY 2009, as a result of a portion of maturing principal not being extended in the final years of the Debt Optimization Program (DOP). The current portion of long-term debt decreased $14.0 million in FY 2009 due to the maturity schedule of debt.

STATEMENT OF OPERATIONS ANALYSIS

Other Income and Expenses showed a net decrease to other revenues of $8.4 million from $106.0 million in FY 2008 to $97.6 million in FY 2009. Investment revenue decreased $1.9 million due to market conditions. The lower investment revenue was offset by lower bond related expenses of $9.5 million. Decreased costs were incurred for plant preservation of $0.8 million with minor increases in cost for decommissioning of $20k and surplus sale activity of $69k.

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. The debt service related activities remain and are net-billed. (See Note 13 to the Financial Statements.)

BALANCE SHEET ANALYSIS

Long-term debt decreased $55.9 million from $1.774 billion in FY 2008 to $1.718 billion in FY 2009, as a result of a portion of the maturing principal not being extended in the final years of the DOP. The current portion of long-term debt decreased $23.9 million in FY 2009 due to the maturity schedule of debt.

STATEMENT OF OPERATIONS ANALYSIS

Overall expenses decreased $8.2 million from FY 2008 related to bond activity. The change in investment income of $1.5 million was due to market conditions.

Business Development Fund

Energy Northwest was created to enable Washington public power utilities and municipalities to build and operate generation projects. 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. Four business lines have been created within the fund: General Services and Facilities, Generation, Professional Services, and Business Unit Support. Each line may have one or more programs that are managed as a unique business activity.

BALANCE SHEET ANALYSIS

Total assets decreased $0.6 million from $6.3 million in FY 2008 to $5.7 million in FY 2009. The decrease to current assets of $1.1 million was due to current funding of operations, mainly due to generation sector development costs. The decrease to current assets was offset by a $0.5 million increase to plant, mostly from the Rattlesnake Mountain Combined Community Communication Facility Project. Liabilities increased $0.7 million from FY 2008 to FY 2009 due to operating activity. Net Assets decreased $1.3 million from $4.5 million in FY 2008 to $3.2 million in FY 2009 due to lower revenue realization with incurred development expenses.

STATEMENT OF OPERATIONS ANALYSIS

Operating Revenues in FY 2009 totaled $8.7 million as compared to FY 2008 revenues of $10.5 million, a decrease of $1.8 million. There was a reduction in wind revenues of $2.3 million from the previous year's sale involving the Reardan Twin Buttes Wind Project. The reduction in wind revenues was partially offset by $0.9 million for Radar Ridge Wind Project reimbursements. Other business activity included a slight revenue increase to Environmental and Calibration Services of $0.1 million and a reduction to revenues of $0.5 million for Professional Services from FY 2008. Net operations for FY 2009 showed an operating loss of $1.3 million, down $1.9 million from the FY 2008 operating gain of $0.6 million. The operating loss reflects increased spending on the Radar Ridge Wind Project along with development costs associated with the Professional Services Sector involving Technical Services.

Though revenues for Business Development declined overall, the generation development team had a successful year relative to wind energy project development, including the complete subscription of the Radar Ridge Wind Project with a potential of up to 82 megawatts-electric capacity. The preparation of the solicitation for the procurement process has commenced. Feasibility and pre-development activities associated with the Mustang Ridge Wind Project, with a potential capacity up to 165 megawatts-electric, culminated with the commencement of marketing effort to subscribe the project's output. This development offers the potential for an innovative teaming arrangement with a private developer who will share the financial risk and provide for the availability of the major equipment with firm pricing.

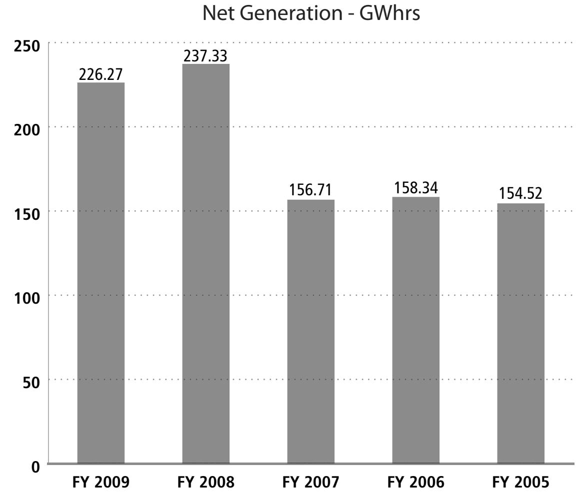
The Business Development Fund receives contributions from the Internal Service Fund to cover cash needs during startup periods. Initial startup costs are not expected to be paid back and are shown as contributions. As an operating business unit, requests can be made to fund incurred operating expenses. In FY 2009, the Business Development Fund did not receive any new contributions (transfers), as compared to an increase of $0.7 million for FY 2008. The contributions (transfers) balance remains at $2.5 million for FY 2009.

Nine Canyon Wind Project

The Nine Canyon Wind Project (Nine Canyon) is wholly owned and operated by Energy Northwest. Nine Canyon is located in the Horse Heaven Hills area southwest of Kennewick, Washington. Electricity generated by Nine Canyon is purchased by Pacific Northwest Public Utility Districts (purchasers). Each purchaser of Phase I has signed a 28-year power purchase agreement with Energy Northwest; each purchaser of Phase II has signed a 27-year power purchase agreement; and each purchaser of Phase III has signed a 23-year power purchase agreement. The agreements are part of the 2nd Amended and Restated Nine Canyon Wind Project Power Purchase Agreement which now have an agreement end date of 2030. Nine Canyon is connected to the Bonneville Power Administration transmission grid via a substation and transmission lines constructed by Benton County Public Utility District.

Phase I of Nine Canyon, which began commercial operation in September 2002, consists of 37 wind turbines, each with a maximum generating capacity of approximately 1.3 MW, for an aggregate generating capacity of 48.1 MW. Phase II of Nine Canyon, which was declared operational in December 2003, includes 12 wind turbines, each with a maximum generating capacity of 1.3 MW, for an aggregate generating capacity of approximately 15.6 MW. Phase III of Nine Canyon, which was declared operational in May 2008, includes 14 wind turbines, each with a maximum generating capacity of 2.3 MW, for an aggregate generating capacity of 32.2 MW. The total Nine

Nine Canyon Wind Project
Net Generation - GWhrs

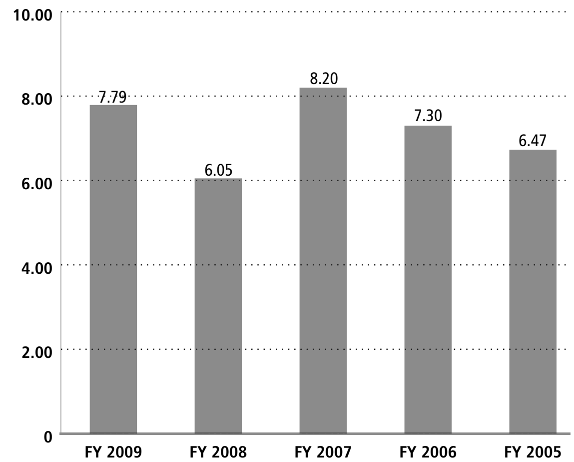


Canyon generating capability is 95.9 MW, enough energy for approximately 39,000 average homes.

Nine Canyon produced 226.27 GWh of electricity in FY 2009 versus 237.33 GWh in FY 2008. Major component outages were less in FY 2009 but wind speed averages were 9.2 percent lower than FY 2008 resulting in the slight decrease of 4.7 percent in generation.

Nine Canyon's performance is measured in several ways, including cost of power. The cost of power for FY 2009 was $7.79 cents/kWh as compared to $6.05 cents/kWh in FY 2008. The cost of power fluctuates year to year depending on various factors such as wind totals and unplanned maintenance. The FY 2009 cost of power increase of 28.8 percent was due to increased fixed costs (depreciation and decommissioning) and increased operations and maintenance costs both related to a full year's costs of the Phase III addition.

Nine Canyon Wind Project
Cost of Power - Cents / kWh



BALANCE SHEET ANALYSIS

Total Assets decreased $13.5 million from $144.8 million in FY 2008 to $131.3 million in FY 2009. Major drivers for the decrease in assets were a decrease to plant of $5.8 million due to a full year's depreciation of Phase III and a decrease to Debt Service funds of $8.1 million due to an early payment of outstanding debt. The remaining amount was an overall increase of $0.4 million due to receivables, prepayments, and debt related activities. The Renewable Energy Performance Incentive (REPI) accrual for FY 2009 was $0.8 million compared to $0.7 million for FY 2008 and reflects funding expectations for the program. There was an overall decrease to liabilities of $12.3 million with $11.9 million related to debt activity and the early payment of outstanding debt. The remaining $0.4 million decrease is due to operating activities. The decrease in Net Assets was $1.2 million in FY 2009 as compared to $2.9 million in FY 2008. The decline experienced in previous years is continuing, though there is a continued trend of improvement from previous periods. The original plan anticipated operating at a loss in the early years and gradually increasing the rate charged to the purchasers to avoid a large rate increase after the REPI expires. The REPI incentive expires 10 years from the initial operation startup date for each phase. Reserves that were established are used to facilitate this plan. The rate plan in FY 2008 was revised to account for the shortfall experienced in the REPI funding and to provide a new rate scenario out to the 2030 project end date.

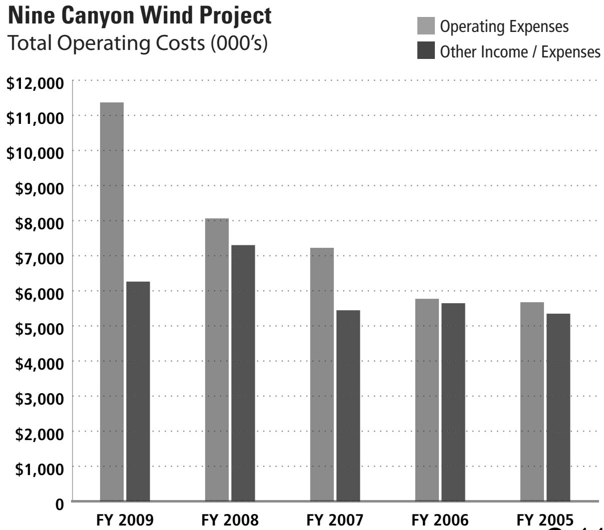
STATEMENT OF OPERATIONS ANALYSIS

Operating Revenues increased from $12.6 million in FY 2008 to $15.6 million in FY 2009. The project received revenue from the billing of the purchasers at an average rate of $69.12 per MWh for FY 2009 as compared to $49.62 per MWh for FY 2008 which is reflective of the implementation of the revised rate plan in FY 2008 to account for REPI funding shortfalls and costs of operations . Revenue was affected by having Phase III on line for the entire year as compared to FY 2008; however, this impact was negated by lower generation. There was an increase in operating expenses of $3.3 million from $8.1 million in FY 2008 to $11.4 million in FY 2009. Change in operating expenses was due to increased depreciation costs of $2.6 million and operations and maintenance costs of $0.7 million due to the Phase III addition. There were minor increases to decommissioning of $2k, administrative and general expenses of $5k, and a minor decrease of $2k to generation tax due to lower generation. Other revenue and expenses decreased $1.1 million from $7.4 million in FY 2008 to $6.3 million in FY 2009. Investment income associated with bond funds increased $0.2 million due to increased funds available for investments and favorable timing. Bond related expenses accounted for the remaining decrease of $0.9 million. Net losses of $2.0 million for FY 2009 continued the trend from previous years. This trend is reflected in the declining Net Assets balance. However, results are improved over the loss reported for FY 2008 of $2.9 million; the positive trend reflects the impact of the revised rate structure and Phase III implementation.

Energy Northwest has accrued, as income (contribution) from DOE, REPI payments that enable Nine Canyon to receive funds based on generation as it applies to the REPI bill. REPI was created 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. Nine Canyon received REPI funding in the amount of $0.8 million for FY 2009, representing its share of funded amounts. The payment stream from Nine Canyon participants and the REPI receipts were projected to cover the total costs over the purchase agreement. Continued shortfalls in REPI funding for the Nine Canyon project led to a revised rate plan to incorporate the impact of this shortfall over the life of the project. The billing rates for the Nine Canyon participants increased 69 percent and 80 percent for Phase I and Phase II participants respectively in FY 2008 in order to cover total project costs, projected out to the 2030 proposed project end date. The increases for FY 2008 were a change from the previous plan where a 3 percent increase each year over the life of the project was projected. Going forward, the increase or decrease in rates will be based on cash requirements of debt repayment and the cost of operations. Phase III started with an initial planning rate of $49.82 per MWh which will increase at 3 percent per year for three years. In year four (FY 2011) the rate will increase to a rate that will be stabilized over the life of the project. Possible adjustments may be necessary to future rates depending on operating costs and REPI, similar to Phase I and II.

Nine Canyon Wind Project
Total Operating Costs (000's)



Internal Service Fund

The Internal Service Fund (ISF) (formerly the General Fund) was established in May 1957. The Internal Service Fund provides services to the other funds. This fund accounts for the central procurement of certain common goods and services for the business units on a cost reimbursement basis. (See Note 1 to Financial Statements.)

BALANCE SHEET ANALYSIS

Total Assets for FY 2009 increased $16.3 million from $37.4 million in FY 2008 to $53.7 million in FY 2009. The five major items for the change were 1) an increase of $17.2 million to Cash for anticipated year end check and warrant redemption, 2) an increase of $1.5 million to Personal Time Bank investments and cash (which represents decreased usage due to R-19 requirements), 3) an increase of $0.7 million in restricted assets due to maturity schedule and escrow requirements processing schedule, 4) a decrease in net plant due to depreciation of $2.3 million, and 5) a decrease to operational activities of $0.8 million.

The net increase in Net Assets and Liabilities is due to increases in Accounts Payable and Payroll related liabilities of $11.0 million and an increase to Sales Tax Payable of $5.0 million, which is tied to movement of fabricated fuel into the State of Washington. The remaining change is due to a $258k increase to Net Assets.

STATEMENT OF OPERATIONS ANALYSIS

Net Revenues for FY 2009 decreased $166k from FY 2008. Investment income decreased $218k due to lower invested balance relating to lower yields. Lease utilization factors remained relatively constant from FY 2008 but reduced improvement costs resulted in a decrease to overall costs of $209k. Results from operations resulted in a $531k decrease to costs with an offsetting increase of $688k due to increased depreciation costs.

Balance Sheets As of June 30, 2009 (Dollars in Thousands)

	Columbia Generating Station	Packwood Lake Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Subtotal	Internal Service Fund	2009 Combined Total
Assets									
CURRENT ASSETS									
Cash	$ 10,092	$ 869	$ 209	$ 179	$ 360	$ 216	$ 11,925	$ 18,876	$ 30,801
Available-for-sale investments	18,029		4,159	5,003	2,485	6,362	36,038	24,488	60,526
Accounts and other receivables	352	263			507	2	1,124	128	1,252
Due from Participants		134					134		134
Due from other business units	4,537	18	441	124	1,023		6,143	464	-
Due from other funds	11,615		2,018	29,313		934	43,880		-
Materials and supplies	92,629						92,629		92,629
Prepayments and other	1,830	81				147	2,058	271	2,329
TOTAL CURRENT ASSETS	139,084	1,365	6,827	34,619	4,375	7,661	193,931	44,227	187,671
CURRENT RESTRICTED ASSETS (NOTE 1)									
Special funds									
Cash	3,364		4	3		1	3,372	583	3,955
Available-for-sale investments	81,743		5,384	8,725		1,550	97,402	1,927	99,329
Accounts and other receivables	127		43	43		828	1,041		1,041
Debt service funds									
Cash	2,411		36	158		3	2,608		2,608
Available-for-sale investments	76,528		87,544	100,945		11,438	276,455		276,455
Accounts and other receivables	42		15	9		112	178		178
Due from other funds	1,935	809	295				3,039		-
TOTAL CURRENT RESTRICTED ASSETS	166,150	809	93,321	109,883	-	13,932	384,095	2,510	383,566
Non Current Assets									
UTILITY PLANT (NOTE 2)									
In service	3,609,698	13,642			1,948	134,151	3,759,439	47,475	3,806,914
Not in service			25,253				25,253		25,253
Accumulated depreciation	(2,321,450)	(12,542)	(25,253)		(648)	(26,965)	(2,386,858)	(40,517)	(2,427,375)
	1,288,248	1,100	-	-	1,300	107,186	1,397,834	6,958	1,404,792
Nuclear fuel, net of accumulated amortization	222,927						222,927		222,927
Construction work in progress	92,390						92,390		92,390
TOTAL NONCURRENT ASSETS	1,603,565	1,100	-	-	1,300	107,186	1,713,151	6,958	1,720,109
DEFERRED CHARGES									
Costs in excess of billings	832,952		1,881,219	1,699,206			4,413,377		4,413,377
Unamortized debt expense	12,057		8,792	6,451		2,472	29,772		29,772
Other deferred charges	8,269	3,649					11,918		11,918
TOTAL DEFERRED CHARGES	853,278	3,649	1,890,011	1,705,657	-	2,472	4,455,067	-	4,455,067
TOTAL ASSETS	$ 2,762,077	$ 6,923	$ 1,990,159	$ 1,850,159	$ 5,675	$ 131,251	$ 6,746,244	$ 53,695	$ 6,746,413

*Project recorded on a liquidation basis.
The accompanying notes are an integral part of these combined financial statements

	Columbia Generating Station	Packwood Lake Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Subtotal	Internal Service Fund	2009 Combined Total
Liabilities And Net Assets									
CURRENT LIABILITIES									
Current maturities of long-term debt	$ 22,375	$ -	$ 40,155	$ 71,280	$ -	$ -	$ 133,810	$ -	$ 133,810
Accounts payable and accrued expenses	42,184	999	292	245	2,495	719	46,934	39,520	86,454
Due to Participants	22,778						22,778		22,778
Due to other funds		809					809		-
Due to other business units						464	464	6,143	-
TOTAL CURRENT LIABILITIES	87,337	1,808	40,447	71,525	2,495	1,183	204,795	45,663	243,042
LIABILITIES- PAYABLE FROM CURRENT RESTRICTED ASSETS (NOTE 1)									
Special funds									
Accounts payable and accrued expenses	118,922		14,773			1,095	134,790	583	135,373
Due to other funds	13,550		2,313	5,493		934	22,290		-
Debt service funds									
Accrued interest payable	58,633	5	47,737	30,918			137,293		137,293
Due to other funds				23,820			23,820		-
TOTAL CURRENT RESTRICTED ASSETS	191,105	5	64,823	60,231	-	2,029	318,193	583	272,666
LONG-TERM DEBT (NOTE 5)									
Revenue bonds payable	2,392,382		1,821,165	1,729,005		144,730	6,087,282		6,087,282
Unamortized (discount)/premium on bonds - net	91,995		81,365	(2,548)		5,126	175,938		175,938
Unamortized gain/(loss) on bond refundings	(11,339)		(17,641)	(8,054)			(37,034)		(37,034)
TOTAL LONG-TERM DEBT	2,473,038	-	1,884,889	1,718,403	-	149,856	6,226,186	-	6,226,186
OTHER LONG-TERM LIABILITIES	10,597	-	-	-	-	-	10,597	-	10,597
DEFERRED CREDITS									
Advances from Members and others								726	726
Other deferred credits		5,110				305	5,415	38	5,453
TOTAL DEFERRED CREDITS	-	5,110	-	-	-	305	5,415	764	6,179
NET ASSETS									
Invested in capital assets, net of related debt					1,300	(40,198)	(38,898)	6,958	(31,940)
Restricted, net						11,599	11,599	1,928	13,527
Unrestricted, net					1,880	6,477	8,357	(2,201)	6,156
NET ASSETS	-	-	-	-	3,180	(22,122)	(18,942)	6,685	(12,257)
TOTAL LIABILITIES	2,762,077	6,923	1,990,159	1,850,159	2,495	153,373	6,765,186	47,010	6,758,670
TOTAL LIABILITIES AND NET ASSETS	$ 2,762,077	$ 6,923	$ 1,990,159	$ 1,850,159	$ 5,675	$ 131,251	$ 6,746,244	$ 53,695	$ 6,746,413

*Project recorded on a liquidation basis.
The accompanying notes are an integral part of these combined financial statements

Statements Of Revenues, Expenses, And Changes In Net Assets

For the year ended June 30, 2009 (Dollars in Thousands)

	Columbia Generating Station	Packwood Lake Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Subtotal	Internal Service Fund	2009 Combined Total
OPERATING REVENUES	$ 519,758	$ 1,641	$ -	$ -	$ 8,738	$ 15,638	$ 545,775	$ -	$ 545,775
OPERATING EXPENSES									
Nuclear fuel	27,118						27,118		27,118
Spent fuel disposal fee	7,380						7,380		7,380
Decommissioning	6,457					76	6,533		6,533
Depreciation and amortization	77,063	36			213	6,736	84,048		84,048
Operations and maintenance	255,380	1,295			12,092	4,459	273,226		273,226
Other power supply expense		111					111		111
Administrative & general	27,123	151				51	27,325		27,325
Generation tax	3,137	20				48	3,205		3,205
TOTAL OPERATING EXPENSES	403,658	1,613	-	-	12,305	11,370	428,946	-	428,946
NET OPERATING REVENUES	116,100	28	-	-	(3,567)	4,268	116,829	-	116,829
OTHER INCOME AND EXPENSE									
Other	888		97,588	87,029	2,201		187,706	72,660	187,964
Investment income	1,993	19	410	494	63	605	3,584	150	3,584
Interest expense and discount amortization	(118,981)	(47)	(96,160)	(85,418)		(6,869)	(307,475)		(307,475)
Plant preservation and termination costs			(1,329)	(2,105)			(3,434)		(3,434)
Depreciation and amortization			(6)				(6)	(2,727)	(6)
Decommissioning			(503)				(503)		(503)
Services to other business units								(69,825)	-
TOTAL OTHER INCOME AND EXPENSES	(116,100)	(28)	-	-	2,264	(6,264)	(120,128)	258	(119,870)
Changes in Net Assets	-	-	-	-	(1,303)	(1,996)	(3,299)	258	(3,041)
(DISTRIBUTION)/CONTRIBUTION	-	-	-	-	-	829	829	-	829
TOTAL NET ASSETS, BEGINNING OF YEAR	-	-	-	-	4,483	(20,955)	(16,472)	6,427	(10,045)
TOTAL NET ASSETS, END OF YEAR	$ -	$ -	$ -	$ -	$ 3,180	$ (22,122)	$ (18,942)	$ 6,685	$ (12,257)

*Project recorded on a liquidation basis.
The accompanying notes are an integral part of these combined financial statements

Statements Of Cash Flows For the year ended June 30, 2009 (Dollars in Thousands)

	Columbia Generating Station	Packwood Lake Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Internal Service Fund	2009 Combined Total
CASH FLOWS FROM OPERATING AND OTHER ACTIVITIES								
Operating revenue receipts	$ 481,142	$ 3,003	$ -	$ -	$ 4,805	$ 16,814	$ -	$ 505,764
Cash payments for operating expenses	(295,537)	(1,287)			(5,887)	(5,696)		(308,407)
Other revenue receipts			129,515	134,013				263,528
Cash payments for preservation, termination expense			(297)	(512)				(809)
Cash payments for services							19,205	19,205
Net cash provided/(used) by operating and other activities	185,605	1,716	129,218	133,501	(1,082)	11,118	19,205	479,281
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES								
Proceeds from bond refundings	214,815		52,403	128,728				395,946
Refunded bond escrow requirement	(125,305)		(51,890)	(127,765)				(304,960)
Deposit to Debt Service Fund	125,305		51,890	127,765				304,960
Payment for bond issuance and financing costs	(2,511)	(10)	(1,415)	(3,034)	(1)	(46)		(7,017)
Payment for capital items	(70,701)	(327)			(500)	(934)	(730)	(73,192)
Receipts from sales of plant assets			35					35
Nuclear fuel acquisitions	(32,998)							(32,998)
Interest paid on revenue bonds	(122,833)	(46)	(92,691)	(122,415)		(10,806)		(348,791)
Principal paid on revenue bond maturities	(25,242)	(1,241)	(61,290)	(142,860)		(8,020)		(238,653)
Escrow refund	5		1	94				100
Net cash provided/(used) by capital and related financing activities	(39,465)	(1,624)	(102,957)	(139,487)	(501)	(19,806)	(730)	(304,570)
CASH FLOWS FROM NON-CAPITAL FINANCE ACTIVITIES	-	-	-	-	-	-	-	-
CASH FLOWS FROM INVESTING ACTIVITIES								
Purchases of investment securities	(949,443)	(3,327)	(351,897)	(423,759)	(15,965)	(44,432)	(62,292)	(1,851,115)
Sales of investment securities	740,411	4,069	324,291	425,905	14,441	43,452	60,947	1,613,516
Interest on investments	2,007	26	547	777	61	496	454	4,368
Net cash provided/(used) by investing activities	(207,025)	768	(27,059)	2,923	(1,463)	(484)	(891)	(233,231)
NET INCREASE (DECREASE) IN CASH	(60,885)	860	(798)	(3,063)	(3,046)	(9,172)	17,584	(58,520)
CASH AT JUNE 30, 2008	76,752	9	1,047	3,403	3,406	9,392	1,875	95,884
CASH AT JUNE 30, 2009	$ 15,867	$ 869	$ 249	$ 340	$ 360	$ 220	$ 19,459	$ 37,364

*Project recorded on a liquidation basis.
The accompanying notes are an integral part of these combined financial statements

Statements Of Cash Flows (Cont'd) For the year ended June 30, 2009 (Dollars in Thousands)

	Columbia Generating Station	Packwood Lake Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Internal Service Fund	2009 Combined Total
RECONCILIATION OF NET OPERATING REVENUES TO NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES								
Net operating revenues	$ 116,100	$ 28	$ -	$ -	$ (3,567)	$ 4,268	$ -	$ 116,829
Adjustments to reconcile net operating revenues to cash provided by operating activities:								
Depreciation and amortization	103,725	25			100	6,712		110,562
Decommissioning	6,457					33		6,490
Other	1,631	338			2,082	46		4,097
Change in operating assets and liabilities:								
Deferred charges/costs in excess of billings	(42,689)	(12)						(42,701)
Accounts receivable	467	203			15			685
Materials and supplies	3,815							3,815
Prepaid and other assets	(528)	(3)			21	(148)		(658)
Due from/to other business units, funds and Participants	(3,594)	1,171			(433)	(29)		(2,885)
Accounts payable	221	(34)			700	236		1,123
Other revenue receipts			129,515	134,013				263,528
Cash payments for preservation, termination expense			(297)	(512)				(809)
Cash payments for services							19,205	19,205
Net cash provided (used) by operating and other activities	$ 185,605	$ 1,716	$ 129,218	$ 133,501	$ (1,082)	$ 11,118	$ 19,205	$ 479,281

*Project recorded on a liquidation basis.
The accompanying notes are an integral part of these combined financial statements

Energy Northwest
Notes to Financial Statements

NOTE 1 - SUMMARY OF OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Energy Northwest, a municipal corporation and joint operating agency of the State of Washington, was organized in 1957 to finance, acquire, construct and operate facilities for the generation and transmission of electric power.

Membership consists of 22 public utility districts and 3 cities. All members own and operate electric systems within the State of Washington.

Energy Northwest is exempt from federal income tax and has no taxing authority.

Energy Northwest maintains seven business units. Each 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 public 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 6).

Energy Northwest operates the Columbia Generating Station (Columbia), a 1,150-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 is preparing an application to renew the license for an additional 20 years, thus continuing operations to 2043. Submittal of this application is planned for January 2010. The estimated duration of the license renewal process is 20-24 months from acceptance of the application. Costs to date on Columbia relicensing are $8.3 million.

Energy Northwest also operates the Packwood Lake Hydroelectric Project (Packwood), a 27.5-MWe generating plant completed in 1964. Packwood operates under a 50-year license from the Federal Energy Regulatory Commission (FERC) that expires on February 28, 2010. The final application for the relicensing of Packwood was submitted to FERC on February 22, 2008. The estimated license renewal process is 18-24 months from the acceptance of application. Costs incurred to date for relicensing are $3.6 million. The electric power produced by Packwood is sold to 12 project participant utilities which pay the costs of Packwood, including the debt service on Packwood revenue bonds. The Packwood participants are obligated to pay annual costs of Packwood including debt service, whether or not Packwood is operable, until the outstanding bonds are paid or provisions are made for bond retirement, in accordance with the requirements of bond resolution. The participants share Packwood revenue as well. In 2002, Packwood and its participants entered into a Power Sales Agreement with Benton and Franklin PUDs to guarantee a specified level of power generation from the Packwood project. This agreement ended in October 2008. In October 2008, Packwood entered into a new Power Sales Agreement with Snohomish PUD to purchase the entire project output (see Note 6).

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. All funding requirements remain as net-billed obligations of Nuclear Projects Nos. 1 and 3. Energy Northwest wholly owns Nuclear Project No. 1. Energy Northwest is no longer responsible for site restoration costs for Nuclear Project No. 3. (See Note 13)

The Business Development Fund was established in April 1997 to pursue and develop new energy related business opportunities. There are four main business lines associated with this business unit: General Services and Facilities, Generation, Professional Services, and Business Unit Support.

Nine Canyon was established in January 2001 for the purpose of exploring and establishing a wind energy project. Phase I of the project was completed in FY 2003 and Phase II was completed in FY 2004. Phase I and II combined capacity is approximately 63.7 MWe. Phase III was completed in FY 2008 adding an additional 14 wind turbines to the Nine Canyon Wind Project and adding an aggregate capacity of 32.2 MWe. The total number of turbines at Nine Canyon is 63 and the total capacity is 95.9 MWe.

The Internal Service 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.

Energy Northwest's fiscal year begins on July 1 and ends on June 30. In preparing these financial statements, the Company has evaluated events and transactions for potential recognition or disclosure through October 30, 2009, the date the financial statements were issued.

The following is a summary of the more significant policies:

a) **<u>Basis of Accounting and Presentation:</u>** The accounting policies of Energy Northwest conform to GAAP applicable to governmental units. The Governmental Accounting Standards Board (GASB) is the accepted standard-setting body for establishing governmental accounting and financial reporting principles. Energy Northwest has applied all applicable GASB pronouncements and elected to apply Financial Accounting Standards Board (FASB) statements and interpretations except for those conflicting with or in contradiction to GASB pronouncements. The accounting and reporting policies of Energy Northwest are regulated by the Washington State Auditor's Office and are based on the Uniform System of Accounts prescribed for public utilities and licensees by FERC. Energy Northwest uses the full accrual basis of accounting where revenues are recognized when earned and expenses are recognized when incurred. Revenues and expenses related to Energy Northwest's operations are considered to be operating revenues and expenses; while revenues and expenses related to capital, financing and investing activities are considered to be other income and expenses. Separate funds and book of accounts 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. (See Note 5)

Energy Northwest maintains an Internal Service Fund for centralized control and accounting of certain capital 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 this Fund and operated for the benefit of other projects. Depreciation relating to capital 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 from Energy Northwest business units are recorded as Current Liabilities–Due to other business units, or as 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 FY 2009 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 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 FASB statements and interpretations, except for those that conflict with, or contradict, GASB pronouncements. Specifically, GASB No. 7, "Advance Refundings Resulting in Defeasance of Debt," and GASB 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 GASB No. 7 and No. 23 is followed. Such guidance governs the accounting for bond defeasances and refundings.

b) **Utility Plant and Depreciation:** Utility plant is recorded at original cost which includes both direct costs of construction or acquisition and indirect costs.

Property, plant, and equipment are depreciated using the straight-line method over the following estimated useful lives:

Buildings and Improvements	20 - 60 years
Generation Plant	40 years
Transportation Equipment	6 - 9 years
General Plant and Equipment	3 - 15 years

Group rates are used for assets and, accordingly, no gain or loss is recorded on the disposition of an asset unless it represents a major retirement. When operating plant assets are retired, their original cost together with removal costs, less salvage, is charged to accumulated depreciation.

The utility plant and net assets of Nuclear Projects Nos. 1 and 3 have been reduced to their estimated net realizable values due to termination. A write-down of Nuclear Projects Nos. 1 and 3 was recorded in FY 1995 and 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.

c) **Allowance for Funds Used During Construction (AFUDC):** For financing not related to a Capital Facility, Energy Northwest analyzes the gross interest expense relating to the cost of the bond sale, taking into account interest earnings and draws for purchase or construction reimbursements for the purpose of analyzing impact to the recording of capitalized interest. However, if estimated costs are more than inconsequential, an adjustment is made to allocate capitalized interest to the appropriate plant account. Interest costs capitalized for FY 2009 totaled $1.9 million and related to Columbia.

d) **Nuclear Fuel:** All expenditures related to the initial purchase of nuclear fuel for Columbia, including interest, were capitalized and carried at cost. When the fuel is placed in the reactor; the fuel cost is amortized to operating expense on the basis of quantity of heat produced for generation of electric energy. Accumulated nuclear fuel amortization (the amortization of the cost of nuclear fuel assemblies in the reactor used in the production of energy and in the fuel pool for less than six months per FERC guidelines) is $121.0 million as of June 30, 2009.

A fuel lease agreement was entered into in FY 2007 and was completed in FY 2009. The agreement provided for an exchange of uranium oxide (U3O8) for an equivalent amount of uranium hexafluoride (UF6), which was returned at the conclusion of the loan.

A fuel agreement was entered into in FY 2009 in which Energy Northwest purchased U3O8 from seller in February 2009. A related transaction will take place in FY 2011 in which Energy Northwest will purchase conversion services from seller. At that time, Energy Northwest will deliver the U3O8 to seller for conversion to UF6. The seller shall deliver to Energy Northwest an equivalent quantity of UF6. This purchase will take place on February 21, 2011.

Energy Northwest has a contract with the U.S. Department of Energy (DOE) that requires the DOE to accept title and dispose of spent nuclear fuel. Although the courts have ruled that DOE had the obligation to accept title to spent nuclear fuel by January 31, 1998, currently, there is no known date established when DOE will fulfill this legal obligation and begin accepting spent nuclear fuel. Energy Northwest is currently seeking damages from DOE to cover interim fuel storage expenses. (See Note 13)

The current period operating expense for Columbia includes a $7.4 million charge from the DOE for future spent fuel storage and disposal in accordance with the Nuclear Waste Policy Act of 1982.

Energy Northwest has completed the Independent Spent Fuel Storage Installation (ISFSI) project, which is a temporary dry cask storage until the DOE completes its plan for a national repository. ISFSI will store the spent fuel in commercially available dry storage casks on a concrete pad at the Columbia site. No casks were issued from the cask inventory account in FY 2009. Spent fuel is transferred from the spent fuel pool to the ISFSI periodically to allow for future refuelings. Current period costs include $25.9 million for nuclear fuel and $1.2 million for dry cask storage costs.

e) **Asset Retirement Obligation:** Energy Northwest has adopted FASB Statement of Financial Accounting Standard (SFAS) No. 143, "Accounting for Asset Retirement Obligations". This statement requires Energy Northwest to recognize the fair value of a liability associated with the retirement of a long-lived asset, such as: Columbia Generating Station, Nuclear Project No. 1, and Nine Canyon, in the period in which it is incurred. (See Note 11)

f) **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. (See Note 12)

g) **Restricted Assets:** In accordance with bond resolutions, related agreements and laws, separate restricted accounts have been established. These assets are restricted for specific uses including debt service, construction, capital additions and fuel purchases, extraordinary operation and maintenance costs, termination, decommissioning, operating reserves, financing, long-term disability, and workers' compensation claims. They are classified as current or non-current assets as appropriate.

h) **Cash and Investments:** For purposes of the Statement of Cash Flows, cash includes unrestricted and restricted cash balances and each business unit maintains their cash and investments. Short-term highly liquid investments are not considered to be cash equivalents, but are classified as available-for-sale investments and are stated at fair value with unrealized gains and losses reported in investment income. (See Note 3) 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. Safe keeping agents, custodians, or trustees hold all investments for the benefit of the individual Energy Northwest business units.

i) **Accounts Receivable:** The percentage of sales method is used to estimate uncollectible accounts. The reserve is then reviewed for adequacy against an aging schedule of accounts receivable. Accounts deemed uncollectible are transferred to the provision for uncollectible accounts on a yearly basis. Accounts receivable specific to each business unit are recorded in the residing business unit.

j) **Other Receivables:** Other receivables include amounts related to the Internal Service Fund from miscellaneous outstanding receivables from other business units which have not yet been collected. The amounts due to each business unit are reflected in the Due To/From other business unit's account. Other receivables specific to each business unit are recorded in the residing business unit.

k) **Materials and Supplies:** Materials and supplies are valued at cost using the weighted average cost method.

l) Long-Term Liabilities: Consist of obligations related to bonds payable and the associated premiums/discounts and gains/losses. Other noncurrent liabilities for CGS only relate to cask activity.

Long-Term Liability activity for the year ending June 30, 2009 is shown below.

Long Term Liabilities (Dollars in Thousands)

	Beginning Balance	Increases	Decreases	Ending Balance
Columbia Generating Station				
Revenue bonds payable	$ 2,359,765	$ 204,110	$ 171,493	$ 2,392,382
Unamortized (discount)/premium on bonds - net	95,341	10,705	14,051	91,995
Unamortized gain/(loss) on bond refundings	(19,336)	7,997		(11,339)
Other noncurrent liabilities	9,337	1,260		10,597
Current portion	6,100	46,095	29,820	22,375
	$ 2,451,207	$ 270,167	$ 215,364	$ 2,506,010
Packwood Lake Hydroelectric Project				
Revenue bonds payable	$ 551	$ -	$ 551	$ -
Unamortized (discount)/premium on bonds - net	(1)	1		-
Unamortized gain/(loss) on bond refundings	14		14	-
Current portion	690		690	-
	$ 1,254	$ 1	$ 1,255	$ -
Nuclear Project No.1				
Revenue bonds payable	$ 1,863,790	$ 49,420	$ 92,045	$ 1,821,165
Unamortized (discount)/premium on bonds - net	93,716	2,983	15,334	81,365
Unamortized gain/(loss) on bond refundings	(31,404)	13,763		(17,641)
Current portion	54,160	40,155	54,160	40,155
	$ 1,980,262	$ 106,321	$ 161,539	$ 1,925,044
Nuclear Project No.3				
Revenue bonds payable	$1,811,025	$117,025	$199,045	$1,729,005
Unamortized (discount)/premium on bonds - net	(22,208)	19,660		(2,548)
Unamortized gain/(loss) on bond refundings	(14,555)	7,244	743	(8,054)
Current portion	95,155	71,280	95,155	71,280
	$ 1,869,417	$ 215,209	$ 294,943	$ 1,789,683
Nine Canyon Wind Project				
Revenue bonds payable	$ 148,435	$ -	$ 3,705	$ 144,730
Unamortized (discount)/premium on bonds - net	5,633		507	5,126
Current portion	4,315		4,315	-
	$ 158,383	$ -	$ 8,527	$ 149,856

m) **Debt Premium, Discount and Expense:** Original issue and reacquired bond premiums, discounts and expenses relating to the bonds are amortized over the terms of the respective bond issues using the bonds outstanding method which approximates the effective interest method. In accordance with GASB Statement No. 23, "Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities", 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.

n) **Revenue Recognition:** 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 accumulated. The difference between cumulative billings received and cumulative expenses is recorded as either billings in excess of costs (deferred credit) or as costs in excess of billings (deferred debit), as appropriate. Such amounts will be settled during future operating periods. (See Note 6)

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 Net Assets for each period.

o) **Capital Contribution:** Energy Northwest has accrued, as income (contribution) from the DOE, Renewable Energy Performance Incentive (REPI) payments that enable Nine Canyon 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 if the Energy Policy Act of 1992, provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. Nine Canyon recorded a receivable for the applied REPI funding in the amount of $0.8 million for FY 2009, representing its share of funded amounts. The payment stream from Nine Canyon participants and the REPI receipts were projected to cover the total costs over the purchase agreement. Permanent shortfalls in REPI funding for the Nine Canyon project led to a revised rate plan to incorporate the impact of this shortfall over the life of the project. The rate schedule for the Nine Canyon participants covers total project costs occurring in FY 2009 and projections out to the 2030 proposed end date.

p) **Compensated Absences:** Employees earn leave in accordance with length of service. Energy Northwest accrues the cost of personal leave in the year when earned. The liability for unpaid leave benefits and related payroll taxes was $18.7 million at June 30, 2009 and is recorded as a current liability.

q) **Use of Estimates:** The preparation of Energy Northwest financial statements in conformity with GAAP requires management to make estimates and assumptions that directly affect the reported amounts of assets and liabilities, disclosures 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 that management considers to be reasonable.

NOTE 2 - UTILITY PLANT

Utility plant activity for the year ended June 30, 2009 was as follows:

Utility Plant Activity (Dollars in Thousands)

	Beginning Balance	Increases	Decreases	Ending Balance
Columbia Generating Station				
Generation	$ 3,547,102	$ 30,127	$ -	$ 3,577,229
Decommissioning	32,469			32,469
Construction Work-in-Progress	52,539	39,851		92,390
Accumulated Depreciation and Decommissioning	(2,246,411)	(75,039)		(2,321,450)
UTILITY PLANT, net*	$ 1,385,699	$(5,061)	$ -	$ 1,380,638
Packwood Lake Hydroelectric Project				
Generation	$ 13,558	$ 84	$ -	$ 13,642
Accumulated Depreciation	(12,517)	(25)		(12,542)
UTILITY PLANT, net	$ 1,041	$ 59	$ -	$ 1,100
Business Development				
Generation	$ 1,327	$ 621	$ -	$ 1,948
Construction Work-in-Progress				-
Accumulated Depreciation	(548)	(100)		(648)
UTILITY PLANT, net	$ 779	$ 521	$ -	$ 1,300
Nine Canyon Wind Project				
Generation	$ 132,356	$ 934	$ -	$ 133,290
Decommissioning	861			861
Construction Work-in-Progress				-
Accumulated Depreciation and Decommissioning	(20,219)	(6,746)		(26,965)
UTILITY PLANT, net	$ 112,998	$ (5,812)	$ -	$ 107,186
Internal Service Fund				
Generation	$ 47,086	$ 389	$ -	$ 47,475
Construction Work-in-Progress				-
Accumulated Depreciation	(37,790)	(2,727)		(40,517)
UTILITY PLANT, net	$ 9,296	$ (2,338)	$ -	$ 6,958

* Does not include Nuclear Fuel Amount of $223 million, net of amortization.

NOTE 3 - DEPOSITS AND INVESTMENTS

As of June 30, 2009, Energy Northwest had the following unrealized gains and losses:

Available-For-Sale-Investments (Dollars in Thousands)

	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value (1) (2)
Columbia Generating Station	$ 176,207	$ 93	$ -	$ 176,300
Packwood Lake Hydroelectric Project	-	-	-	-
Nuclear Project No. 1	97,087	-	-	97,087
Nuclear Project No. 3	114,673	-	-	114,673
Business Development Fund	2,484	1	-	2,485
Internal Service Fund	26,423	21	(29)	26,415
Nine Canyon Wind Project	19,215	149	(14)	19,350

(1) All investments are in U.S. Government backed securities

(2) The majority of investments have maturities of less than 1 year. Approximately $9.35 million have a maturity beyond 1 year with the longest maturity being June 10, 2011.

Interest rate risk: In accordance with its investment policy, Energy Northwest manages its exposure to declines in fair values by limiting investments to those with maturities designated in specific bond resolutions.

Credit risk: Energy Northwest's investment policy restricts investments to debt securities and obligations of the U.S.Treasury, U.S. Government agencies, Federal National Mortgage Association and the Federal Home Loan Banks, certificates of deposit and other evidences of deposit at financial institutions qualified by the Washington Public Deposit Protection Commission (PDPC), and general obligation debt of state and local governments and public authorities recognized with one of the three highest credit ratings (AAA, AA+, AA, or equivalent). This investment policy is more restrictive than the state law.

Concentration of credit risk: Energy Northwest investment policy does not specifically address concentration of credit risk. An individual authorized security or obligation can receive up to 100 percent of the authorized investment amount; there are no individual concentration limits.

Custodial credit risk, Deposits: For a deposit, this is the risk that in the event of bank failure, Energy Northwest's deposits may not be returned to it. Energy Northwest's interest bearing accounts and certificates of deposits are covered up to $250,000 by Federal Depository Insurance Corporation (FDIC) while non-interest bearing deposits are entirely covered by FDIC and if necessary, all interest and non-interest bearing deposits are covered by collateral held in multiple financial institution collateral pool administered by the Washington State Treasurer's Local Government Investment Pool (PDPC). Under state law, public depositories under the PDPC may be assessed on a prorated basis if the pool's collateral is insufficient to cover a loss. As a result, deposits covered by collateral held in the multiple financial institution collateral pool are considered to be insured. State law requires deposits may only be made with institutions that are approved by the PDPC.

NOTE 4 - DEFERRED CHARGES AND DEFERRED CREDITS

Other deferred charges of $8.3 million and $3.6 million relate to the Columbia and Packwood relicensing effort, respectively.

NOTE 5 - 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. Nine Canyon's bonds were authorized by the following resolutions: Resolution No. 1214 2001 Bonds, Resolution No. 1299 2003 Bonds, Resolution No. 1376 2005 Bonds and Resolution No.1482 2006 Bonds.

During the year ended June 30, 2009, Energy Northwest issued, for Nuclear Projects No. 1 and 3, and Columbia, the Series 2009-A Bonds and Series 2009-B Bonds. The Series 2009-C Bonds were issued for Columbia. The Series 2009-A, 2009-B, 2009-C Bonds issued for Nuclear Project No. 1, Nuclear Project No. 3, and Columbia are fixed rate bonds with a weighted average coupon interest rate ranging from 4.83 percent to 5.67 percent. These transactions resulted in a net-loss for accounting purposes of $0.03 million. According to GASB No. 23, "Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities," gains and losses on the refundings are deferred and amortized over the remaining life of the old debt or the new debt, whichever is shorter.

The Series 2009-A Bonds issued for Nuclear Project No. 1, Nuclear Project No. 3, and Columbia are tax exempt fixed-rate bonds that extended debt.

The Series 2009-B Bonds, issued for Nuclear Project No. 1, Nuclear Project No. 3 and Columbia are taxable fixed-rate bonds for the purpose of paying costs relating to the issuance of the Series 2009-A, Series 2009-B, and Series 2009-C Bonds, as well as certain costs relating to the refunding of certain outstanding bonds.

The Series 2009-C Bonds issued for Columbia are tax exempt fixed-rate bonds to finance a portion of the cost of certain capital improvements at Columbia.

Nuclear Projects Nos. 1 and 3 have long-term debt that contains variable rate interest. These rates are set periodically through a weekly rate reset. These rates ranged from 0.200 percent to 9.240 percent during FY 2009.

The Bond Proceeds, Weighted Average Coupon Interest Rates, Net Accounting Loss, and Total Defeased Bonds for 2009-A, 2009-B, and 2009-C are presented in the following tables:

BOND PROCEEDS (dollars in millions)

	2009A	2009B	2009C	Total
Project 1	$ 51.89	$ 0.51	$ -	$ 52.40
CGS	125.30	18.51	71.00	214.81
Project 3	127.76	0.97	-	128.73
Total	$ 304.95	$ 19.99	$ 71.00	$ 395.94

WEIGHTED AVERAGE COUPON INTEREST RATE FOR REFUNDED BONDS

	2009A	2009B	2009C
Total	5.42%*	-	-

* The 2009A issue refunded variable rate bonds that are not included.

WEIGHTED AVERAGE COUPON INTEREST RATE FOR NEW BONDS

	2009A	2009B	2009C
Total	4.83%	5.67%	4.88%

NET ACCOUNTING LOSS (dollars in millions)

	2009A	2009B	2009C	Total
Project 1	$ (0.51)	$ 0.51	$ -	$ -
CGS	(2.15)	1.21	-	(0.94)
Project 3	0.01	0.96	-	0.97
Total	$ (2.65)	$ 2.68	$ -	$ 0.03

TOTAL DEFEASED

	2009A	2009B	2009C	Total
Project 1	$ 51.89	$ -	$ -	$ 51.89
CGS	125.30	-	-	125.30
Project 3	127.76	-	-	127.76
Total	$ 304.95	$ -	$ -	$ 304.95

Energy Northwest did not issue or refund any bonds associated with Packwood or Nine Canyon for FY 2009. All remaining bonded debt related to Packwood was paid off prior to June 30, 2009.

In prior fiscal years, Energy Northwest also defeased certain revenue bonds by placing the net proceeds from the refunding bonds in irrevocable trusts to provide for all required future debt service payments on the refunded bonds until their dates of redemption. Accordingly, the trust account assets and liability for the defeased bonds are not included in the financial statements in accordance with GASB statements No. 7 and 23. Including the FY 2009 defeasements, $44.8 million, $25.9 million, and $125.3 million of defeased bonds were not called or had not matured at June 30, 2009, for Nuclear Projects Nos. 1 and 3, and Columbia respectively.

Outstanding principal on revenue and refunding bonds for the various business units as of June 30, 2009, and future debt service requirements for these bonds are presented in the following tables:

Outstanding Long-Term Debt

As Of June 30, 2009 (Dollars In Thousands)

COLUMBIA REVENUE AND REFUNDING BONDS

Series	Coupon Rate (%)	Serial or Term Maturities		Amount
1992A	6.30	7-1-2012	$	50,000
1994A	5.40	7-1-2012		100,107
2001A	5.00-5.50	7-1-13/2017		186,600
2002A	5.20-5.75	7-1-17/2018		157,260
2002B	5.35-6.00	7-1-2018		123,815
2003A	5.50	7-1-10/2015		132,970
2003B	4.15	7-1-2009		4,530
2003F	5.00-5.25	7-1-10/2018		33,165
2004A	5.25	7-1-10/2018		259,680
2004B	5.50	7-1-2013		12,715
2004C	5.25	7-1-10/2018		21,275
2005A	5.00	7-1-15/2018		114,985
2005C	4.34-4.74	7-1-09/2015		91,890
2006A	5.00	7-1-20/2024		434,210
2006B	5.23	7-1-2011		4,420
2006C	5.00	7-1-20/2024		62,200
2006D	5.80	7-1-2023		3,425
2007A	5.00	7-1-13/2018		77,575
2007B	5.07-5.33	7-1-12/2021		10,665
2007D	5.00	7-1-21/2024		35,080
2008A	5.00-5.25	7-1-14/2018		110,935
2008B	3.60-5.95	7-1-09/2021		14,850
2008C	5.00-5.25	7-1-21/2024		37,240
2008D	5.00	7-1-10/2012		127,510
2008E	4.15	7-1-2009		3,545
2009A	3.00-5.00	7-1-14/2018		116,425
2009B	4.59-6.80	7-1-14/2024		18,515
2009C	4.25-5.00	7-1-20/2024		69,170
		Revenue bonds payable	$	2,414,757
		Estimated fair value at June 30, 2009	$	2,589,514 (B)

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

NUCLEAR PROJECT NO.1 REFUNDING REVENUE BONDS

Series	Coupon Rate (%)	Serial or Term Maturities		Amount
1989B	7.125	7-1-2016	$	41,070
1990B	7.25	7-1-2009		2,695
1993B	7.00	7-1-2009		5,855
1996C	6.00	7-1-2009		6,335
1998A	5.75	7-1-2009		2,810
2001A	4.50-5.50	7-1-10/2013		76,560
2002A	5.50-5.75	7-1-13/2017		248,485
2002B	6.00	7-1-2017		101,950
2003A	5.50	7-1-13/2017		241,455
2003B	4.06	7-1-2009		18,210
2004A	5.25	7-1-2013		62,485
2004B	5.50	7-1-2013		1,135
2005A	5.00	7-1-13/2015		72,175
2006A	5.00	7-1-10/2017		271,325
2007A	5.00	7-1-13/2017		51,730
2007B	5.07-5.10	7-1-12/2013		6,740
2007C	5.00	7-1-13/2017		219,020
2008A	5.00-5.25	7-1-13/2017		230,535
2008B	3.60	7-1-2009		2,155
2008D	5.00	7-1-10/2017		70,125
2008E	4.15	7-1-2009		2,095
2009A	3.25-5.00	7-1-14/2015		48,905
2009B	4.59	7-1-2014		515
1993-1A-1	VARIABLE			33,055
1993-1A-2	VARIABLE			33,055
1993-1A-3	VARIABLE			10,845
		Revenue bonds payable	$	1,861,320
		Estimated fair value at June 30, 2009	$	2,039,177 (B)

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

Outstanding Long-Term Debt (Cont'd)

As Of June 30, 2009 (Dollars In Thousands)

NUCLEAR PROJECT NO.3 REFUNDING REVENUE BONDS

Series	Coupon Rate (%)	Serial or Term Maturities	Amount	
1989A	(A)	7-1-09/2014	$ 8,893	
1989B	(A)	7-1-09/2014	29,224	
	7.125	7-1-2016	76,145	
			105,369	
1990B	(A)	7-1-09/2010	4,871	
1993B	7.00	7-1-2009	9,050	
1993C	(A)	7-1-13/2018	23,963	
1997A	6.00	7-1-2009	5,235	
2001A	5.50	7-1-10/2018	151,380	
2001B	5.50	7-01-2018	10,675	(C)
2002B	6.00	7-01-2016	75,360	
2003A	5.50	7-1-11/2017	241,915	
2003B	4.15	7-1-2009	21,575	
2004A	5.25	7-1-14/2016	83,835	
2004B	5.50	7-1-2013	1,515	
2005A	5.00	7-1-13/2015	129,265	
2006A	5.00	7-1-16/2018	39,445	
2007A	4.50-5.00	7-1-13/2018	84,465	
2007B	5.07	7-1-2012	1,725	
2007C	5.00	7-1-12/2018	61,085	
2008A	5.25	7-1-2018	13,790	
2008B	3.70	7-1-2010	110	
2008D	5.00	7-1-10/2017	62,270	
2008E	4.15	7-1-2009	2,485	
2009A	5.00-5.25	7-1-14/2018	116,055	
2009B	4.59	7-1-2009	970	
1993-3A-3	VARIABLE		15,795	
2003E	VARIABLE		98,025	
2008-F1	VARIABLE		104,415	
2008-F2	VARIABLE		104,415	
		Compound interest bonds accretion	222,335	
		Revenue bonds payable	$ 1,800,285	
		Estimated fair value at June 30, 2009	$ 1,895,512	(B)

(A) Compound Interest Bonds
(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.
(C) Auction Rate Certificates that will have a rate of 5.50% through 7/1/2010 and a variable rate thereafter until 7/1/2018.

NINE CANYON WIND PROJECT REFUNDING REVENUE BONDS

Series	Coupon Rate (%)	Serial or Term Maturities	Amount	
2003	3.75-5.00	7-1-10/2023	$ 17,600	
2005	4.50-5.00	7-1-10/2023	57,720	
2006	4.50-5.00	7-1-10/2030	69,410	
		Revenue bonds payable	$ 144,730	
		Estimated fair value at June 30, 2009	$ 145,357	(B)

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

Total Bonds Payable	$ 6,221,092
Estimated fair value at June 30, 2009	$ 6,669,560

Debt Service Requirements

As Of June 30, 2009 (Dollars In Thousands)

COLUMBIA GENERATING STATION

Fiscal Year	Principal	Interest	Total
6/30/2009 Balance*	$ 22,375	$ 56,530	$ 78,905
2010	156,795	126,473	283,268
2011	94,395	116,239	210,634
2012	266,717	111,547	378,264
2013	69,090	97,006	166,096
2014-2017	631,765	324,754	956,519
2018-2022	884,460	178,007	1,062,467
2023-2024	289,160	22,155	311,315
	$ 2,414,757	$ 1,032,711	$ 3,447,468

* Principal and interest due July 1, 2009.

NUCLEAR PROJECT NO. 1

Fiscal Year	Principal	Interest	Total
6/30/2009 Balance*	$ 40,155	$ 47,274	$ 87,429
2010	83,890	92,974	176,864
2011	92,550	88,687	181,237
2012	91,140	84,431	175,571
2013	313,435	80,087	393,522
2014	367,680	64,133	431,813
2015	191,540	45,529	237,069
2016	326,665	36,274	362,939
2017	354,265	18,994	373,259
	$ 1,861,320	$ 558,383	$ 2,419,703

* Principal and interest due July 1, 2009

NUCLEAR PROJECT NO. 3

Fiscal Year	Principal	Interest	Total
6/30/2009 Balance*	$ 46,492	$ 54,308	$ 100,800
2010	35,232	98,844	134,076
2011	83,539	88,352	171,891
2012	70,606	84,769	155,375
2013	133,440	89,264	222,704
2014-2017	826,840	216,474	1,043,314
2018	381,801	21,889	403,690
Adjustment **	222,335	(222,335)	-
	$ 1,800,285	$ 431,565	$ 2,231,850

* Principal and interest due July 1, 2009.
** Adjustment for Compound Interest Bonds accretion; Compound Interest Bonds are reflected at their face amount less discount on the balance sheet

NINE CANYON WIND PROJECT

Fiscal Year	Principal	Interest	Total
6/30/2009 Balance*	$ -	$ -	$ -
2010	3,965	6,963	10,928
2011	4,260	6,774	11,034
2012	4,575	6,570	11,145
2013	6,930	6,351	13,281
2014-2017	31,310	21,873	53,183
2018-2022	48,495	18,134	66,629
2023-2030	45,195	8,692	53,887
	$ 144,730	$ 75,357	$ 220,087

* Principal and interest due July 1, 2009.

NOTE 6- NET BILLING

Security - Nuclear Projects Nos. 1 and 3 and Columbia

The participants have purchased all of the capability of Nuclear Projects Nos. 1 and 3 and Columbia. BPA has in turn acquired the entire capability from the participants under contracts referred to as net-billing agreements. Under the net-billing agreements for each of the business units, participants are obligated to pay Energy Northwest a pro-rata share of the total annual costs of the respective projects, including debt service on bonds relating to each business unit. BPA is then obligated to reduce amounts from participants under BPA power sales agreements by the same amount. The net-billing agreements provide that participants and BPA are obligated to make such payments whether or not the projects are completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of the projects' output.

On May 13, 1994, Energy Northwest's Board of Directors adopted resolutions terminating Nuclear Projects Nos. 1 and 3. The Nuclear Projects Nos. 1 and 3 project agreements and the net-billing agreements, except for certain sections which relate only to billing processes and accrued liabilities and obligations under the net-billing agreements, ended upon termination of the projects. Energy Northwest entered into an agreement with BPA to provide for continuation of the present budget approval, billing and payment processes. With respect to Nuclear Project No. 3, the ownership agreement among Energy Northwest and private companies was terminated in FY 1999. (See Note 13)

Security - Packwood Lake Hydroelectric Project

The Packwood participants, Benton PUD, and Franklin PUD had a Power Sales Agreement extending through October 2008. This agreement was not renewed and a new Power Sales agreement between the Packwood participants and Snohomish PUD, effective October 2008, ensued. Under the agreement, Snohomish PUD purchases all of the output directly. The power purchase agreement (PPA) provides a predetermined rate for all firm delivery, per the contract schedule and the Mid-Columbia (Mid-C) based rate for all firm deliveries above firm, or secondary power. Packwood is obligated to supply a specified amount of power. If power production does not supply the required amount of power, Packwood is required to provide any shortfall by purchasing power on the open market which resulted in $0.1 million of purchased power in FY 2009. Conversely, if there is excess capacity per the PPA with Snohomish PUD, Packwood sells the excess on the open market for additional revenues to be included as part of the PPA with the Packwood participants. The Packwood participants are obligated to pay annual costs of the project including debt service, whether or not Packwood 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 Packwood participants also share project revenue to the extent that the amounts exceed project costs.

NOTE 7 - PENSION PLANS

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, Communications Unit, P.O. Box 48380, Olympia, WA 98504-8380. The following disclosures are made pursuant to GASB Statement 27, "Accounting for Pensions by State and Local Government Employers." Any information obtained from the DRS is the responsibility of the State of Washington. PricewaterhouseCoopers LLP (PwC), independent auditors for Energy Northwest, has not audited or examined any of the information available from the DRS; accordingly, PwC does not express an opinion or any other form of assurance with respect thereto.

Public Employees' Retirement System (PERS)
Plans 1, 2, and 3

PERS is a cost-sharing multiple-employer retirement system comprised of three separate plans for membership purposes: Plans 1 and 2 are defined benefit plans and Plan 3 is a defined benefit plan with a defined contribution component.

Membership in the system includes: elected officials; state employees; employees of the Supreme, Appeals, and Superior courts (other than judges currently in a judicial retirement system); employees of legislative committees; community and technical colleges, college and university employees not participating in national higher education retirement programs; judges of district and municipal courts; and employees of local governments.

PERS participants who joined the system by September 30, 1977, are Plan 1 members. Those who joined on or after October 1, 1977, and by either, February 28, 2002, for state and higher education employees, or August 31, 2002, for local government employees, are Plan 2 members 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 irrevocable option of choosing membership in either PERS Plan 2 or PERS Plan 3. The option must be exercised within 90 days of employment. An employee is reported in Plan 2 until a choice is made. Employees who fail to choose within 90 days default to PERS Plan 3. Notwithstanding, PERS Plan 2 and Plan 3 members may opt out of plan membership if terminally ill, with less than five years to live.

PERS defined benefit retirement benefits are financed from a combination of investment earnings and employer and employee contributions. PERS retirement benefit provisions are established in state statute and may be amended only by the State Legislature.

Plan 1 members are vested after the completion of five years of eligible service. Plan 1 members are eligible for retirement at any age after 30 years of service, or at the age of 60 with five years of service, or at the age of 55 with 25 years of service. The annual benefit is 2 percent of the average final compensation (AFC) per year of service, capped at 60 percent. (The AFC is based on the greatest compensation during any 24 eligible consecutive compensation months.) Plan 1 members who retire from inactive status prior to the age of 65 may receive actuarially reduced benefits. The benefit is actuarially reduced to reflect the choice of a survivor option. A cost-of living allowance (COLA) is granted at age 66 based upon years of service times the COLA amount, increased by 3 percent annually. Plan 1 members may also elect to receive an optional COLA that provides an automatic annual adjustment based on the Consumer Price Index. The adjustment is capped at 3 percent annually. To offset the cost of this annual adjustment, the benefit is reduced.

Plan 2 members are vested after the completion of five years of eligible service. Plan 2 members may retire at the age of 65 with five years of service, or at the age of 55 with 20 years of service, with an allowance of 2 percent of the AFC per year of service. (The AFC is based on the greatest compensation during any eligible consecutive 60-month period.) Plan 2 members who retire prior to the age of 65 receive reduced benefits. If retirement is at age 55 or older with at least 30 years of service, a 3 percent per year reduction applies; otherwise an actuarial reduction will apply. The benefit is also actuarially reduced to reflect the choice of a survivor option. There is no cap on years of service credit; and a cost-of-living allowance is granted (based on the Consumer Price Index), capped at 3 percent annually.

Plan 3 has a dual benefit structure. Employer contributions finance a defined benefit component, and member contributions finance a defined contribution component. The defined benefit portion provides a benefit calculated at 1 percent of the AFC per year of service. (The AFC is based on the greatest compensation during any eligible consecutive 60-month period.) Effective June 7, 2006, Plan 3 members are vested in the defined benefit portion of their plan after 10 years of service; or after five years of service, if 12 months of that service are earned after age 44; or after five service credit years earned in PERS Plan 2 prior to June 1, 2003. Plan 3 members are immediately vested in the defined contribution portion of their plan. Vested Plan 3 members are eligible to retire with full benefits at age 65, or at age 55 with 10 years of service. Plan 3 members who retire prior to the age of 65 receive reduced benefits. If retirement is at age 55 or older with at least 30 years of service, a 3 percent per year reduction applies; otherwise an actuarial reduction will apply. The benefit is also actuarially reduced to reflect the choice of a survivor option. There is no cap on years of service credit, and Plan 3 provides the same cost-of-living allowance as Plan 2.

The defined contribution portion can be distributed in accordance with an option selected by the member, either as a lump sum or pursuant to other options authorized by the Employee

Retirement Benefits Board.

There are 1,190 participating employers in PERS. Membership in PERS consisted of the following as of the latest actuarial valuation date for the plans of September 30, 2007:

Retirees and beneficiaries receiving benefits	71,244
Terminated plan members entitled to but not yet receiving benefits	26,583
Active plan members vested	105,447
Active plan members non-vested	52,575
Total	**255,849**

Funding Policy

Each biennium, the state Pension Funding Council adopts Plan 1 employer contribution rates, Plan 2 employer and employee contribution rates, and Plan 3 employer contribution rates. Employee contribution rates for Plan 1 are established by statute at 6 percent for state agencies and local government unit employees, and at 7.5 percent for state government elected officials. The employer and employee contribution rates for Plan 2 and the employer contribution rate for Plan 3 are developed by the Office of the State Actuary to fully fund Plan 2 and the defined benefit portion of Plan 3. All employers are required to contribute at the level established by the Legislature. Under PERS Plan 3, employer contributions finance the defined benefit portion of the plan, and member contributions finance the defined contribution portion. The Employee Retirement Benefits Board sets Plan 3 employee contribution rates. Six rate options are available ranging from 5 to 15 percent; two of the options are graduated rates dependent on the employee's age. The methods used to determine the contribution requirements are established under state statute in accordance with chapters 41.40 and 41.45 RCW.

The required contribution rates expressed as a percentage of current year covered payroll, as of December 31, 2008, were as follows:

	PERS Plan 1	PERS Plan 2	PERS Plan 3
Employer*	8.31%**	8.31%**	8.31%***
Employee	6.00%****	5.45%****	*****

* The employer rates include the employer administrative expense fee currently set at 0.16 percent.
** The employer rate for state elected officials is 12.39 percent for Plan 1 and 8.31 percent for Plan 2 and Plan 3.
*** Plan 3 defined benefit portion only.
**** The employee rate for state elected officials is 7.50 percent for Plan 1 and 5.45 percent for Plan 2.
***** Variable from 5.0 percent minimum to 15.0 percent maximum based on rate selected by the PERS 3 member.

Both Energy Northwest and the employees made the required contributions. Energy Northwest's required contributions for the years ended June 30 were as follows:

	PERS Plan 1	PERS Plan 2	PERS Plan 3
2009	$ 244,531	$ 6,774,304	$ 2,964,075
2008	$ 201,971	$ 4,313,031	$ 1,702,720
2007	$ 174,813	$ 3,235,922	$ 1,269,321

The contributions above represent the full liability under the system. Any future pension benefits would be reflected in future years as changes in contribution rates. Historical trends and projections are available from the DRS and also disclosed in the CAFR.

NOTE 8 - DEFERRED COMPENSATION PLANS

Energy Northwest provides a 401(k) Deferred Compensation Plan (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. Participants are immediately vested in their contributions and direct the investment of their contribution. Each participant may elect to contribute pre-tax annual compensation, subject to current Internal Revenue Service limitations.

For the 401(k) Plan, Energy Northwest may elect to make an employer matching contribution for each of its employees who are a participant during the plan year. The amount of such an employer match shall be 50 percent of the maximum salary deferral percentage. During FY 2009 Energy Northwest contributed $2.2 million in employer matching funds.

NOTE 9 - OTHER EMPLOYMENT BENEFITS – POST-EMPLOYMENT

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. There are 83 retirees that remain participants in the insurance program. 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 life insurance benefit has a maximum limit of $10,000 for retiree after December 31, 1994. The cost of coverage for retirees remained unchanged for FY 2009 and was $2.82 per $1,000 of coverage. Employees who retired prior to January 1, 1995, contribute $.58 per $1,000 of coverage while Energy Northwest pays the remainder; retirees after December 31, 1994, pay 100 percent of the cost coverage. Premiums are paid to the insurer on a current period basis. At the time each employee retired, Energy Northwest accrued an estimated liability for the actuarial value of the future premium. Energy Northwest revises the liability for the actuarial value of estimated future premiums, net of retiree contributions. The total liability recorded at June 30, 2009, was $0.7 million for these benefits.

During FY 2009, 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. This allocation basis resulted in the following percentages by business unit for FY 2009 for this and other allocated costs; Columbia at 94 percent; Business Development at 4 percent; and Project 1, Nine Canyon, Packwood and Project 3 receiving the residual amount of 2 percent.

NOTE 10 - INSURANCE

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.

Federal law under the Price Anderson Act currently limits public liability claims from a nuclear incident. As of June 30, 2009, the current limit was $12.5 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. As required by law, Energy Northwest has purchased the maximum commercial insurance available of $300 million, which is the primary layer of protection. The remaining balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the United States results in claims that exceed the individual licensee's primary insurance layer. The current maximum deferred premium for each nuclear incident is $117.5 million per reactor, but not more than $17.5 million per reactor may be charged in any one year for each incident. 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 $2.8 billion. The deductible for this coverage is $5.0 million per occurrence.

NOTE 11 - ASSET RETIREMENT OBLIGATION (ARO)

Energy Northwest adopted SFAS No. 143 on July 1, 2002. This Statement requires an entity to recognize the fair value of a liability of an ARO 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 are discounted using a credit-adjusted-risk-free rate, and 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 Net Assets 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, Nuclear Project No. 1 and Nine Canyon. Decommissioning and site restoration requirements for Columbia and Nuclear Project No. 1 are governed by the NRC regulations and site certification agreements between Energy Northwest and the State of Washington and regulations adopted by the Washington Energy Facility Site Evaluation Council (EFSEC) and a lease agreement with the DOE. (See Notes 1 and 13) Additionally, there are separate lease agreements for land located at Nine Canyon. Leases at these locations are considered operating leases and expenses were $38.3k for Columbia, $35.0k for Nuclear Project No. 1 and $569.4k for the Nine Canyon project.

As of June 30, 2009, Columbia has a capital decommissioning net asset value of $17.6 million and an accumulated liability of $117.1 million for the generating plant, and for the ISFSI a net asset value of $1.2 million and an accumulated liability of $1.8 million.

An adjustment was made in FY 2009 for Nuclear Project No. 1 to account for costs incurred for decommissioning and site restoration. Costs incurred in FY 2009 of $0.1 million combined with the current year accretion expense of $0.7 million and downward revision in future restoration estimates of $0.1 million resulted in a small increase to the ARO of $0.5 million. Nuclear Project No. 1 has a capital decommissioning net asset value of zero and an accumulated liability of $14.8 million.

Under the current agreement, Nine Canyon 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 original ARO in FY 2003 for Phase I and II. Phase III began commercial operation in FY 2008 and the original ARO was adjusted to reflect the change in scenario for the retirement obligation, with current lease agreements reflecting a 2030 expiration date. As of June 30, 2009, Nine Canyon has a capital decommissioning net asset value of $.7 million and an accumulated liability of $1.1 million.

Packwood's obligation has not been calculated because the time frame and extent of the obligation was considered under this statement as indeterminate. As a result, no reasonable estimate of the ARO obligation can be made. An ARO will be required to be recorded if circumstances change. Management believes that these assets will be used in utility operations for the foreseeable future.

The following table describes the changes to Energy Northwest's ARO liabilities for the year ended June 30, 2009:

ASSET RETIREMENT OBLIGATION (dollars in millions)

Columbia Generating Station		
Balance At June 30, 2008	$	111.27
Current year accretion expense		5.82
ARO at June 30, 2009	$	117.09
ISFSI		
Balance At June 30, 2008	$	1.67
Current year accretion expense		0.09
ARO at June 30, 2009	$	1.76
Nuclear Project No. 1		
Balance At June 30, 2008	$	14.27
Less: Restoration costs incurred		(0.12)
Current year accretion expense		0.73
Revision in future restoration estimates		(0.11)
ARO at June 30, 2009	$	14.77
Nine Canyon Wind Project		
Balance At June 30, 2008	$	1.05
Current year accretion expense		0.04
ARO at June 30, 2009	$	1.09

NOTE 12 - DECOMMISSIONING AND SITE RESTORATION

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 (See Note 11 concerning related ARO for Columbia). 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 2009.

Energy Northwest's current estimate of Columbia's decommissioning costs in 2009 dollars is $877.0 million (Columbia - $872.7 million and ISFSI - $4.3 million). This estimate, which is updated biannually, is based on the NRC minimum amount required to demonstrate reasonable financial assurance for a boiling water reactor with the power level of Columbia.

Site restoration requirements for Columbia are governed by the site certification agreements between Energy Northwest and the State of Washington and by regulations adopted by the EFSEC. Energy Northwest submitted a site restoration plan for Columbia that was approved by the EFSEC on June 12, 1995. Energy Northwest's current estimate of Columbia's site restoration costs is $107.1 million in constant dollars (based on the 2009 study) and is updated biannually along with the decommissioning estimate.

Both decommissioning and site restoration estimates (based on 2009 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, 2009, totaled approximately $117.9 million and $17.3 million, respectively. Since September 1996, these amounts have been held and managed by BPA in external trust funds in accordance with NRC requirements and site certification agreements; the balances in these external trust funds are not reflected on Energy Northwest's Balance Sheet. Energy Northwest established a second decommissioning and site restoration plan for the ISFSI. Beginning in FY 2003, an annual contribution is made to the Energy Northwest Decommissioning Fund. These contributions are held by Energy Northwest and not held in trust by BPA. The fair market value of cash and investments as of June 30, 2009, is $0.7 million. These contributions will occur through FY 2029; cash payments will begin for decommissioning and site restoration in FY 2025 with equal installments for five years totaling $2.06 million.

NOTE 13 - 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 below under "Nuclear Project No. 1 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 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. 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 Project No. 1 Site Restoration

Site restoration requirements for Nuclear Project No. 1 is 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 Project No. 1 to EFSEC on March 8, 1995, which complied with EFSEC requirements to remove the assets and restore the sites by demolition, burial, entombment, or other techniques such that the sites pose minimal hazard to the public. EFSEC approved Energy Northwest's site restoration plan on June 12, 1995. In its approval, EFSEC recognized that there is uncertainty associated with Energy Northwest's proposed plan. Accordingly, EFSEC's conditional approval provides for additional reviews once the details of the plan are finalized. A new plan with additional details was submitted in FY 2003. This submittal was used to calculate the ARO discussed in Note 11.

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 by the members and others of a communication network in conjunction with BPA.

The Business Development Fund has a 7.38 percent interest in NoaNet with a potential mandate of an additional 25 percent step-up possible for a maximum 9.23 percent. NoaNet has $18.4 million in network revenue bonds outstanding, based on their June 30, 2009 unaudited statements. The members are obligated to pay the principal and interest on the bonds when due in the event and to the extent that NoaNet's Gross Revenue (after payment of costs of Maintenance and Operation) is insufficient for this purpose. The maximum principal share (based on step-up potential) that the Business Development Fund could be required to pay is $1.7 million. It is important to note that the Business Development Fund is not obligated to reimburse losses of NoaNet unless an assessment is made to NoaNet's members based on a two-thirds vote of the membership. In FY 2009 the Business Development Fund contributed $186k 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 $9.0 million as of June 30, 2009. Future equity contributions, if any, will be treated the same until NoaNet has a positive equity position. Financial statements for NoaNet may be obtained by writing to: Northwest Open Access Network, NoaNet Headquarters, 5802 Overlook Ave. NE, Tacoma, WA 98422. Any information obtained from NoaNet is the responsibility of NoaNet. PwC has not audited or examined any information available from NoaNet; accordingly, PwC does not express an opinion or any other form of assurance with respect thereto.

Other Litigation and Commitments

Energy Northwest v. United States of America filed in U.S. Court of Federal Claims in January 2004 (Cause No. 04-0010C). This is an action for breach of contract and breach of implied covenant of good faith and fair dealing brought by Energy Northwest against the United States (Department of Energy, "DOE") for damages for DOE's failure to meet its legal obligations to accept and dispose of spent nuclear fuel and high-level radioactive waste per the contract. Energy Northwest's claim is in the amount of $56.8 million. A bench trial was conducted in February 2009, and the Court has taken the matter under advisement. No time frame has been provided for when a decision will be rendered.

Grays Harbor Energy LLC v. Energy Northwest filed with American Arbitration Association in Seattle, WA, in April 2008 (Case No. 75-158-115-08). A demand for arbitration was filed by Invenergy (under the name Grays Harbor Energy LLC) related to the interpretation of a "First Power Purchase Option" contract between the parties. Invenergy seeks declaratory relief that the Option is null and void. Energy Northwest filed a counterclaim requesting damages for breach of the Option. The matter was fully arbitrated before an arbitration panel, with the hearing concluding on July 23, 2009. On August 18, 2009, the panel issued its decision awarding in favor of Energy Northwest on all counts. Energy Northwest received a cash settlement ($1.3 million) as well as a month to month call option for a period of 3.5 years.

Energy Northwest is involved in other 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.

Current Debt Ratings (Unaudited)

Energy Northwest (Long-Term)	Net-Billed Rating	Nine Canyon Rating
Fitch, Inc.	AA	A-
Moodys Investors Service, Inc. (Moodys)	Aaa	A3
Standard and Poor's Ratings Services (S & P)	AA	A-

Variable Rate Debt	S&P	FITCH	MOODYS
Letter of Credit Banks			
Bank of America			
Long-Term	A+		Aa3
Short-Term	A-1		VMIG1
JPMorgan Chase Bank			
Long-Term	AA-	AA	Aa1
Short-Term	A-1+	F1+	VMIG1
VRDN's			
Liquidity Provider			
Dexia			
Long-Term	AA	AA	Aaa
Short-Term	A-1	F1+	VMIG1
Bond Insurance (Long-Term)			
Financial Security Assurance	AAA	AA	Aa2

PROPOSED FORM OF OPINIONS OF BOND COUNSEL

Energy Northwest

Goldman, Sachs & Co.

Citigroup Global Markets Inc.

J.P. Morgan Securities Inc.

Prager, Sealy & Co., LLC

Merrill Lynch, Pierce, Fenner & Smith Incorporated

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 [$71,965,000/$91,775,000/$309,845,000] [Project 1/Columbia Generating Station/Project 3] Electric Revenue [Refunding] Bonds, [Series 2010-A,]Series 2010-B [and Series 2010-C (Taxable Build America Bonds)] (the "2010 Bonds"). The 2010 Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/1042/838] (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on [November 23, 1993/October 23, 1997/November 23, 1993], as amended by a resolution adopted on March 21, 2001, and (iii) a Supplemental Resolution adopted by the Executive Board on February 25, 2010 (the "Supplemental Resolution"). The Electric Revenue Bond Resolution and the Supplemental Resolution are hereinafter collectively referred to as the "Bond Resolutions." All capitalized terms used herein and not otherwise defined shall have the respective meanings ascribed thereto in the Bond Resolutions.

The 2010 Bonds are subject to redemption in the manner and upon the terms and conditions set forth in the Bond Resolutions. The 2010 Bonds rank junior as to security and payment to bonds issued and outstanding under the Prior Lien Resolution. The 2010 Bonds rank equally as to security and payment with all other Parity Debt.

Regarding questions of fact material to our opinion, we have relied on representations of Energy Northwest in the Bond Resolutions and in the certified proceedings and on other certifications of public officials and others furnished to us without undertaking to verify the same by independent investigation.

Based on the foregoing, we are of the opinion that, under existing law:

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 2010 Bonds and apply the proceeds of the 2010 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 2010 Bonds and other Parity Debt are valid and binding upon Energy Northwest and are enforceable in accordance with their terms.

3. The 2010 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 2010 Bonds are payable solely from the revenues and other amounts pledged to such

payment under the Bond Resolutions. The 2010 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 2010 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,

FOSTER PEPPER PLLC

PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL

Energy Northwest

Goldman, Sachs & Co.

Citigroup Global Markets Inc.

J.P. Morgan Securities Inc.

Prager, Sealy & Co., LLC

Merrill Lynch, Pierce, Fenner & Smith Incorporated

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 [$71,965,000/$91,775,000/$309,845,000] [Project 1/Columbia Generating Station/Project 3] Electric Revenue [Refunding] Bonds, [Series 2010-A,] Series 2010-B [and Series 2010-C (Taxable Build America Bonds)] (the "2010 Bonds"). The 2010 Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/1042/838] (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on [November 23, 1993/October 23, 1997/November 23, 1993], as amended, and (iii) a Supplemental Resolution adopted by the Executive Board on February 25, 2010 (the "Supplemental Resolution"). The Electric Revenue Bond Resolution and the Supplemental Resolution are hereinafter collectively referred to as the "Bond Resolutions." All capitalized terms used herein and not otherwise defined shall have the respective meanings ascribed thereto in the Bond Resolutions.

In connection with the issuance of the 2010 Bonds, Energy Northwest has requested that we examine the validity of the WPPSS No. [1/2/3] Project Net Billing Agreements (the "Net Billing Agreements") and the Project No. [1/2/3] Assignment Agreement, dated as of August 24, 1984 (the "Assignment Agreement"), (collectively the "Agreements") by and between Energy Northwest and the United States of America, Department of Energy, acting by and through the Administrator (the "Administrator") of the Bonneville Power Administration ("Bonneville").

For the purpose of rendering this opinion, we have reviewed the following:

(a) The Constitution of the State and such statutes and regulations as we deemed relevant to this opinion, including particularly the Act;

(b) The Constitution of the United States of America and such statutes and regulations as we deemed relevant to this opinion, including particularly the Bonneville Project Act of 1937, as amended (the "Bonneville Act"), the Flood Control Act of 1944, Public Law 88-552, as amended, the Federal Columbia River Transmission System Act of 1974, as amended, and the Pacific Northwest Electric Power Planning and Conservation Act of 1980, as amended;

(c) Certified copies of the Electric Revenue Bond Resolution and the Supplemental Resolution;

(d) Certified copies of the Net Billing Agreements and the Assignment Agreement;

(e) The Certificate of the Chairman or Vice Chairman of the Executive Board, dated the date hereof, certifying that (i) neither Energy Northwest nor, to the best of his knowledge, any other party thereto has taken any action to (1) repeal, modify or terminate the Net Billing Agreements or the Assignment Agreement, or (2) repeal any proceeding authorizing the execution and delivery of any such Agreement, and (ii) to the best of his knowledge, each such Agreement remains in full force and effect as of the date hereof;

(f) The Certificate of the Administrator, dated the date hereof, certifying that (i) neither the Administrator nor, to the best of his knowledge, any other party thereto has taken any action to (1) repeal, modify or terminate the Net Billing Agreements or the Assignment Agreement, or (2) repeal any proceeding authorizing the execution and delivery of any such Agreement, and (ii) to the best of his knowledge, each such Agreement remains in full force and effect as of the date hereof;

(g) Certified copies of the proceedings of Energy Northwest authorizing the execution and delivery of the Net Billing Agreements and the Assignment Agreement and such other documents, proceedings and matters relating to the authorization, execution and delivery of such Agreements by each of the parties thereto as we deemed relevant;

(h) The opinion of General Counsel to Bonneville, dated the date hereof, to the effect that, *inter alia*, (i) the office of Administrator was duly established and is validly existing under the Bonneville Act, (ii) the Administrator was duly authorized to execute and deliver the Net Billing Agreements and the Assignment Agreement, and (iii) each of the Net Billing Agreements and the Assignment Agreement has been duly authorized, executed and delivered by the Administrator and did not constitute a violation of or conflict with the provisions of applicable law;

(i) The decision of the United States Court of Appeals for the Ninth Circuit in *City of Springfield v. Washington Public Power Supply System*, *et al*., 752 F.2d 1423 (9th Cir. 1985), *cert. denied*, 474 U.S. 1055 (1986)) ("Springfield");

(j) A certified copy of Energy Northwest Resolution No. [769/640/775] as amended and supplemented (the "Prior Lien Resolution"); and

(k) Such other documents, agreements, proceedings, pleadings, court decisions, statutes, matters and questions of law as we deemed necessary or appropriate for the purposes hereof.

Based upon the foregoing and in reliance thereon and based on the assumptions, exceptions and conclusions listed below, we are of the opinion that each of the Net Billing Agreements (which as to Projects 1 and 3 consists of only Sections 5(a), 5(b), 7, 10 and 13 thereof) and the Assignment Agreement is a legal and valid obligation of Energy Northwest, Bonneville Power Administration and the Participants currently obligated under the Net Billing Agreements, enforceable against such parties in accordance with its terms.

The foregoing opinion is subject to the following limitations, qualifications, exceptions, and assumptions:

(A) In rendering the opinion as to the enforceability of the Net Billing Agreements as to the Participants, we have assumed the continued obligations of Bonneville, and performance by Bonneville of its obligations as therein stated, under the Net Billing Agreements and Assignment Agreement. The assumption in the prior sentence does not limit or affect our opinion as to the enforceability of the Net Billing Agreements and Assignment Agreement against Bonneville.

(B) The enforceability of all such Agreements may be subject to (i) the valid exercise of sovereign state police powers; (ii) the limitations on legal remedies against the United States of America under Federal law now or hereafter enacted; (iii) applicable bankruptcy, insolvency, reorganization, moratorium and other similar laws or enactments now or hereafter enacted by any state or the Federal government affecting the enforcement of creditors' rights; and (iv) the unavailability of equitable remedies or the application of general principles of equity (regardless of whether enforcement is sought in a proceeding in equity or at law).

(C) In rendering this opinion, (a) we have assumed with your consent (1) the authenticity of all documents submitted to us as originals, the genuineness of all signatures, the legal capacity of natural persons, and the conformity to the originals of all documents submitted to us as copies; (2) the truth and accuracy of all representations set forth in the Certificates of the Chairman or Vice Chairman of the Executive Board and the Administrator referred to above in paragraphs (e) and (f); and (3)(A) the due incorporation and valid organization and existence as a municipality, publicly owned utility or rural electric cooperative, as applicable, of each Participant, (B) the due authorization by such Participant of the requisite governmental or corporate action, as the case may be, and due execution and delivery of the Net Billing Agreement to which such Participant is a party and that all assignments of any Participant's obligations under the Net Billing Agreements were properly done, and (C) with respect to the Participant's obligations under the Net Billing Agreements, no violation of or conflict with the provisions of applicable law, and (b) we have, with your consent, relied on the opinion of General Counsel to Bonneville referred to above in paragraph (h) as to the matters described therein.

(D) The opinions expressed herein are qualified to the extent that the characterization of, and the enforceability of any rights or remedies in the Agreements, may be limited by concepts of materiality, reasonableness, good faith and fair dealing, and rules governing specific performance, injunctive relief, marshalling, subrogation and other equitable remedies, regardless of whether raised in a court of law or otherwise. The opinions expressed herein are based on an analysis of existing laws (including, but not limited to, the law that provides that Bonneville may make expenditures from the Bonneville Fund which have been included in Bonneville's budget submitted to Congress without further appropriation or fiscal year limitation), regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after the date hereof.

(E) We express no opinion with respect to any provision for a remedy which is determined to be in the nature of a penalty, forfeiture or punitive damages, or which would provide the claimant with a duplication of damage awards or cumulative remedy, or which waives the applicability of any rule requiring an election of remedies. We express no opinion with respect to the obligation of Bonneville or any Participant to pay any debt or other obligation related to the Project on an accelerated basis.

(F) Our opinions are subject to the context rule of interpretation of contracts, which provides that even though terms of a contract may be unambiguous, courts may admit extrinsic evidence to interpret the contract.

This letter has been prepared solely for your use in connection with the transactions contemplated by the Agreements and should not be quoted in whole or in part or otherwise be referred to nor be relied upon by, filed with or furnished to, any governmental agency or other person or entity (other than your legal and professional advisors) without the prior consent of this firm. No attorney-client relationship has existed or exists between our firm and Bonneville, the Participants or the Underwriters with respect to the subject matter hereof or by virtue of this opinion. This letter opinion speaks as of its date and we do not hereby undertake to update this letter opinion. The opinions expressed in this letter are limited to the matters set forth in this letter, and no other opinions should be inferred beyond the matters expressly stated.

Very truly yours,

FOSTER PEPPER PLLC

[THIS PAGE INTENTIONALLY LEFT BLANK]

PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL
FOR THE SERIES 2010-A BONDS AND THE SERIES 2010-C (TAXABLE) BUILD AMERICA BONDS

Energy Northwest
P.O. Box 968
Richland, Washington 99352

Energy Northwest
$71,150,000 Project 1 Electric Revenue Refunding Bonds, Series 2010-A
$279,980,000 Project 3 Electric Revenue Refunding Bonds, Series 2010-A
$75,770,000 Columbia Generating Station Electric Revenue Bonds, Series 2010-C (Taxable Build America Bonds)

Ladies and Gentlemen:

We have acted as Special Tax Counsel to the Bonneville Power Administration in connection with the issuance by Energy Northwest (formerly known as the Washington Public Power Supply System), a municipal corporation and joint operating agency of the State of Washington, of $71,150,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2010-A (the "Project 1 2010-A Bonds"), $279,980,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2010-A (the "Project 3 2010-A Bonds," and together with the Project 1 2010-A Bonds, the "Series 2010-A Bonds") and $75,770,000 aggregate principal amount of Columbia Generating Station Electric Revenue Bonds, Series 2010-C (Taxable Build America Bonds) (the "Series 2010-C (Taxable) Build America Bonds"). The Project 1 2010-A 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 February 25, 2010 (the "Project 1 Resolution"). The Series 2010-C (Taxable) Build America 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 February 25, 2010 (the "Columbia Resolution"). The Project 3 2010-A 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 February 25, 2010 (the "Project 3 Resolution," and together with the Project 1 Resolution and the Columbia Resolution, the "Resolutions"). The Resolutions provide that the Series 2010-A Bonds are being issued for the purpose of refunding certain outstanding bonds issued by Energy Northwest. The Resolutions provide that the Series 2010-C (Taxable) Build America Bonds are being issued for the purpose of financing a portion of the costs of certain capital improvements at the Columbia Generating Station.

In such connection, we have reviewed certified copies of the Resolutions, the two Tax Matters Certificates executed and delivered by Energy Northwest on the date hereof and the two Tax Matters Certificates executed and delivered by the Bonneville Power Administration on the date hereof (collectively, the "Tax Certificates"); the opinion of Foster Pepper PLLC, as Bond Counsel, dated the date hereof (the "Bond Counsel Opinion"); 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.

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. Accordingly, this opinion speaks only as of its date and is not intended to, and may not, be relied upon in connection with any such actions, events or matters. Our engagement with respect to the Series 2010-A Bonds and Series 2010-C (Taxable) Build America 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, all 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 2010-A Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights and obligations under the Series 2010-A Bonds, the Resolutions and the Tax Certificates and their enforceability may be subject to 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 cases 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 February 25, 2010 relating to the Series 2010-A Bonds and the Series 2010-C (Taxable) Build America Bonds, or other offering material relating to those Bonds and express no opinion with respect thereto.

We have relied with your consent on the Bond Counsel Opinion with respect to the validity of the Series 2010-A Bonds and the Series 2010-C (Taxable) Build America Bonds and with respect to the due authorization and issuance of the Series 2010-A Bonds and Series 2010-C (Taxable) Build America Bonds.

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

1. Interest on the Series 2010-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").

2. Interest on the Series 2010-A Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes. We express no opinion as to whether some or all interest on the Series 2010-A Bonds is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income.

3. Interest on the Series 2010-C (Taxable) Build America Bonds is not excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act, Section 103 of the 1954 Code or Section 103 of the Internal Revenue Code of 1986, as amended.

We express no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the Series 2010-A Bonds and the Series 2010-C (Taxable) Build America Bonds.

Series 2010-C (Taxable) Build America Bonds Circular 230 Disclaimer:

Investors are urged to obtain independent tax advice regarding the Series 2010-C (Taxable) Build America Bonds based upon their particular circumstances. The tax discussion above regarding the Series 2010-C (Taxable) Build America Bonds was not intended or written to be used, and cannot be used, for the purposes of avoiding taxpayer penalties. The advice was written to support the promotion or marketing of the Series 2010-C (Taxable) Build America Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE SERIES 2010-B BONDS

Energy Northwest
P.O. Box 968
Richland, Washington 99352

Energy Northwest
$815,000 Project 1 Electric Revenue Refunding Bonds, Series 2010-B
$16,005,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2010-B
$29,865,000 Project 3 Electric Revenue Refunding Bonds, Series 2010-B

Ladies and Gentlemen:

We have acted as Special Tax Counsel to the Bonneville Power Administration in connection with the issuance by Energy Northwest (formerly known as the Washington Public Power Supply System), a municipal corporation and joint operating agency of the State of Washington, of $815,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2010-B (the "Project 1 2010-B Bonds"), $16,005,000 aggregate principal amount of Columbia Generating Station Electric Revenue Refunding Bonds, Series 2010-B (the "Columbia 2010-B Bonds"), $29,865,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2010-B (the "Project 3 2010-B Bonds," and together with the Project 1 2010-B Bonds and the Columbia 2010-B Bonds, the "Series 2010-B Bonds"). The Project 1 2010-B 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 February 25, 2010 (the "Project 1 Resolution"). The Columbia 2010-B 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 February 25, 2010 (the "Columbia Resolution"). The Project 3 2010-B 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 February 25, 2010 (the "Project 3 Resolution," and together with the Project 1 Resolution and the Columbia Resolution, the "Resolutions"). The Resolutions provide that the Series 2010-B Bonds are being issued for the purpose of refunding certain outstanding bonds issued by Energy Northwest.

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, the Tax Matters Certificate executed and delivered by the Bonneville Power Administration on the date hereof, the Tax Matters Certificate executed and delivered by Energy Northwest on March 11, 2010 in connection with the issuance of its Project 1 Electric Revenue Refunding Bonds, Series 2010-A (the "Project 1 2010-A Bonds") and its Project 3 Electric Revenue Refunding Bonds, Series 2010-A (the "Project 3 2010-A Bonds" and, together with the Project 1 2010-A Bonds, the "Series 2010-A Bonds"), and the Tax Matters Certificate executed and delivered by the Bonneville Power Administration on March 11, 2010 in connection with the issuance of the Series 2010-A Bonds (collectively, the "Tax Certificates"); the opinions of Foster Pepper PLLC, as Bond Counsel, dated March 11, 2010 and the date hereof (the "Bond Counsel Opinions"); 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.

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. Accordingly, this opinion speaks only as of its date and is not intended to, and may not, be relied upon in connection with any such actions, events or matters. Our engagement with respect to the Series 2010-B 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, all 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 2010-B Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights and obligations under the Series 2010-B Bonds, the Resolutions and the Tax Certificates and their enforceability may be subject to 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 cases 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 February 25, 2010 relating to the Series 2010-B Bonds, or other offering material relating to the Series 2010-B Bonds and express no opinion with respect thereto.

We have relied with your consent on the Bond Counsel Opinions, with respect to the validity of the Series 2010-B Bonds, the due authorization and issuance of the Series 2010-B Bonds and other matters.

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

1. Interest on the Series 2010-B 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").

2. Interest on the Series 2010-B Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes. We express no opinion as to whether some or all interest on the Series 2010-B Bonds is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income.

We express no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the Series 2010-B Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

ENERGY NORTHWEST
PARTICIPANT UTILITY SHARE OF
FISCAL YEAR 2010 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.

[THIS PAGE INTENTIONALLY LEFT BLANK]

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 the Hanford Generating Project ("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.

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 2009 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.

[THIS PAGE INTENTIONALLY LEFT BLANK]

SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE 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 2010 Bonds have additionally defined "Defeasance Obligations" to mean, with respect to the 2010 Bonds, any "Government Obligations" as that term is defined in Chap. 39.53 RCW and as it may be hereafter amended.

"Electric Revenue Bond Resolution" shall mean Resolution No. 835, adopted on November 23, 1993, as amended and supplemented, Resolution No. 1042, adopted on October 23, 1997, as amended and supplemented, and Resolution No. 838, adopted on November 23, 1993, as amended and supplemented.

"*Engineer*" shall mean any nationally recognized independent engineer or engineering firm appointed by Energy Northwest, and may be the Consulting Engineer appointed pursuant to Resolutions Nos. 769, 640 and 775.

"Government Obligations" means (a) direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by the United States of America and bank certificates of deposit secured by such obligations; (b) bonds, debentures, notes, participation certificates, or other obligations issued by the banks for cooperatives, the federal intermediate credit bank, the federal home loan bank system, the export-import bank of the United States, federal land banks, or the federal national mortgage association; (c) public housing bonds and project notes fully secured by contracts with the United States; and (d) obligations of financial institutions insured by the federal deposit insurance corporation or the federal savings and loan insurance corporation, to the extent insured or to the extent guaranteed as permitted under any provision of state law, as such definition may be amended.

"*Investment Securities*" shall mean any of the following, if and to the extent that the same are legal for the investment of funds of Energy Northwest:

(i) direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America;

(ii) obligations of any agency, subdivision, department, division or instrumentality of the United States of America, including, without limitation, the Federal Home Loan Mortgage Corporation, the Federal Agricultural Mortgage Corporation, the Student Loan Marketing Association and the International Bank for Reconstruction and Development; or obligations fully guaranteed as to interest and principal by any agency, subdivision, department, division or instrumentality of the United States of America;

(iii) direct obligations of, or obligations guaranteed as to principal and interest by, any state or direct obligations of any agency or public authority thereof, insured or uninsured, provided such obligations are rated, at the time of purchase, in one of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds;

(iv) bank time deposits evidenced by certificates of deposit and bankers' acceptances issued by any bank or trust company (which may include the Trustee) which is a member of the Federal Deposit Insurance Corporation (or any successor thereto), provided that such time deposits and bankers' acceptances (a) do not exceed at any one time in the aggregate five percent (5%) of the total of the capital and surplus of such bank or trust company, or (b) are secured by obligations described in items (i) or (ii) of this definition of Investment Securities, which such obligations at all times have a market value at least equal to such time deposits so secured;

(v) repurchase agreements with (1) any bank or trust company (which may include the Trustee) which is a member of the Federal Deposit Insurance Corporation (or any successor thereto), or (2) any securities broker which is a member of the Securities Investor Protection Corporation, which such agreements are secured by securities which are obligations described in items (i) or (ii) of this definition of Investment Securities, provided that each such repurchase agreement (a) is in commercially reasonable form and is for a commercially reasonable period, and (b) results in transfer to the Trustee or Energy Northwest of legal title to, or the grant to the Trustee or Energy Northwest of a prior perfected security interest in, identified securities referred to in items (i) or (ii) of this definition which are free and clear of any claims by third parties and are segregated in a custodial or trust account held by a third party (other than the repurchaser) as the agent solely of, or in trust solely for the benefit of, the Trustee or Energy Northwest; provided that such securities acquired pursuant to such repurchase agreements shall be valued at the lower of the then current market value of such securities or the repurchase price thereof set forth in the applicable repurchase agreement;

(vi) certificates or other obligations that evidence ownership of the right to payments of principal of or interest on obligations of the United States of America or any state of the United States of America or any political subdivision thereof or any agency or instrumentality of the United States of America or any state or political subdivision, provided that such obligations shall be held in trust by a bank or trust company or a national banking association meeting the requirements for a Trustee under the Electric Revenue Bond Resolutions, and provided further that, in the case of certificates or other obligations that evidence ownership of the right to payments of principal or interest on obligations of a state or political subdivision, the payments of all principal of and interest on such certificates or such obligations shall be fully insured or unconditionally guaranteed by, or otherwise unconditionally payable pursuant to a credit support arrangement provided by, one or more financial institutions or insurance companies or associations which shall be rated in the highest rating category by each rating agency then rating the Electric Revenue Bonds or, in the case of an insurer providing municipal bond insurance policies insuring the payment, when due, of the principal of and interest on municipal bonds, such insurance policy shall result in such municipal bonds being rated in the highest rating category by each rating agency then rating the Electric Revenue Bonds;

(vii) investment agreements rated in one of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds or the long-term unsecured debt obligations of the issuer of which are rated in one of the two highest rating categories by the respective agency rating such investment agreements or investment agreements which result in transfer to the Trustee or Energy Northwest of legal title to, or the grant to the Trustee or Energy Northwest of a prior perfected security interest in, identified securities referred to in items (i) or (ii) of this definition which are free and clear of any claims by third parties and are segregated in a custodial or trust account held by a third party (other than the counterparty to the investment agreement) as the agent solely of, or in trust solely for the benefit of, the Trustee or Energy Northwest;

(viii) bankers' acceptances drawn on and accepted or guaranteed by a commercial bank rated in either of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds;

(ix) commercial paper rated, at the time of purchase, in the highest rating category by each rating agency then rating the Electric Revenue Bonds;

(x) shares of any publicly offered mutual fund of the type commonly known as a "money market fund" that, at the time of investment, has at least 85% of its assets directly invested in securities of the type described in items (i), (ii) and (iii) of this definition of Investment Securities; and

(xi) such other investments with respect to any Series of Electric Revenue Bonds as shall be specified in the Supplemental Electric Revenue Bond Resolution authorizing such Series of Electric Revenue Bonds.

"Outstanding" or "outstanding" shall mean, as if any date, (a) when used with reference to Electric Revenue Bonds, all Electric Revenue Bonds theretofore or thereupon issued or authorized pursuant to the Electric Revenue Bond Resolution, except: (i) any Electric Revenue Bonds paid in full, surrendered for cancellation or cancelled at or prior to such date (including any Bond held in escrow pending settlement of any tender offer by Energy Northwest or the Trustee on its behalf, but excluding any Option Bond so held pending settlement of a purchase on a tender date); and (ii) Electric Revenue Bonds in lieu of or in substitution for which other Electric Revenue Bonds shall have been authenticated or delivered pursuant to the Electric Revenue Bond Resolution; and (iii) Electric Revenue Bonds deemed to be no longer outstanding under the Electric Revenue Bond Resolution as provided therein or under any Supplemental Resolution authorizing the issuance of a Series of Electric Revenue Bonds, (b) when used with reference to Prior Lien Bonds shall have the meaning assigned to such term in the Prior Lien

Resolution, and (c) when used with reference to Subordinate Lien Obligations shall have the meaning assigned to such term by the instrument or instruments under which such Subordinate Lien Obligations are issued.

"*Parity Debt*" shall mean bonds, notes or other obligations issued under a resolution or resolutions authorized pursuant to the Electric Revenue Bond Resolutions, the Electric Revenue Bonds and any Parity Reimbursement Obligation.

"*Parity Reimbursement Obligation*" shall mean a reimbursement obligation the payment of which, pursuant to the provisions of a Supplemental Electric Revenue Bond Resolution, is secured as to payment by the pledge created by the Electric Revenue Bond Resolutions.

"*Payment Agreement*" shall mean a written agreement which provides for an exchange of payments based on interest rates, or for ceilings or floors on such payments, or an option on such payments, or any combination, entered into on either a current or forward basis.

"*Payment Date*" shall mean each date on which interest shall be due and payable and each date on which both interest shall be due and payable and a scheduled Principal Installment (whether by payment of principal scheduled to mature or a sinking fund installment to be paid) shall be required to be made on any of the outstanding Electric Revenue Bonds according to their respective terms.

"*Principal Installment*" shall mean, as of any date of calculation and with respect to any Series or Subseries, as the case may be, (a) the principal amount of Electric Revenue Bonds (including any amount designated in, or determined pursuant to, the applicable Supplemental Electric Revenue Bond Resolution, as the "principal amount" with respect to any bonds) of such Series or subseries scheduled to mature on a certain future date for which no sinking fund installments have been established, or (b) the unsatisfied balance of sinking fund installments scheduled to be paid on a certain future date for Electric Revenue Bonds of such Series or subseries, or (c) if such future dates coincide as to different Electric Revenue Bonds of such Series or subseries, the sum of such principal amount and such unsatisfied balance scheduled to mature or to be paid on such future date; in each case in the amounts and on the dates as provided in the applicable Supplemental Electric Revenue Bond Resolution authorizing such Series or subseries regardless of any retirement of Electric Revenue Bonds except pursuant to Section 505 of the Electric Revenue Bond Resolutions or (d) that portion of a Parity Reimbursement Obligation which corresponds to the amount of principal scheduled to mature or a sinking fund installment scheduled to be paid or that portion of a Parity Reimbursement Obligation payable on a certain future date which corresponds to the amount of principal scheduled to mature or a sinking fund installment scheduled to be paid.

"Prior Lien Bonds" shall mean, collectively, the bonds heretofore or hereafter issued pursuant to the Prior Lien Resolutions.

"Prior Lien Resolutions" shall mean, collectively, Resolution No. 769, adopted on September 18, 1975, as amended and supplemented, Resolution No. 640, adopted on June 26, 1973, as amended and supplemented, and Resolution No. 775, adopted on December 3, 1975, as amended and supplemented.

"*Rating Agency*" shall mean Fitch, Inc. ("Fitch"), Moody's Investors Service, Inc. ("Moody's") or Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P") or, if either Fitch, Moody's or S&P no longer furnishes ratings on a particular Series of the Electric Revenue Bonds, as the case may be, then such other nationally recognized rating agency then rating such Series of the Electric Revenue Bonds, as the case may be.

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

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

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

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

"*Subordinate Lien Obligation*" shall mean any bond, note, certificate, warrant or other evidence of indebtedness of Energy Northwest authorized by the Electric Revenue Bond Resolution.

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

Effect of Amendments Adopted March 9, 2001 (Project 1, Columbia and Project 3)

The Supplemental Resolutions adopted by the Executive Board of Energy Northwest on March 9, 2001, amend the Project 1, Columbia and Project 3 Electric Revenue Bond Resolutions, respectively, to add a covenant to the effect that, from and after the issuance of the Series 2001-A Bonds, Energy Northwest will not issue or authorize the issuance of Prior Lien Bonds under the related Prior Lien Resolution and shall not otherwise create any other special fund or funds for the payment of bonds, warrants or other obligations which will rank on a parity with the pledge and lien on the Revenues created by such Prior Lien Resolution.

Each Supplemental Resolution also amends the related Electric Revenue Bond Resolution to add a definition of the term "Energy Northwest" and to change the definition of the term "System," as follows:

"Energy Northwest" shall mean the joint operating agency organized and existing under the provisions of the Act and formerly known as the Washington Public Power Supply System.

"System" shall mean Energy Northwest.

The Project 1 Supplemental Resolution further amends the Project 1 Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Project 1 Electric Revenue Bond Resolution, from and after the date of adoption of the Project 1 Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Project 1 Electric Revenue Bond Supplemental Resolution, shall be known as "Energy Northwest Project 1 Electric Revenue Bonds."

The Columbia Supplemental Resolution further amends the Columbia Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution, from and after the date of adoption of the Columbia Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Columbia Electric Revenue Bond Supplemental Resolution, shall be known, as "Energy Northwest Columbia Generating Station Electric Revenue Bonds."

The Project 3 Supplemental Resolution further amends the Project 3 Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Project 3 Electric Revenue Bond Resolution, from and after the date of adoption of the Project 3 Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Project 3 Electric Revenue Bond Supplemental Resolution, shall be known, as "Energy Northwest Project 3 Electric Revenue Bonds."

Electric Revenue Bond Resolutions to Constitute Contract (Section 103)

Each Electric Revenue Bond Resolution constitutes a contract between Energy Northwest and the owners from time to time of the Electric Revenue Bonds, and the issuer of a Credit Facility, if any, relating to such subseries of Electric Revenue Bonds; and the pledge made in each related Electric Revenue Bond Resolution and the covenants and agreements therein set forth to be performed on behalf of Energy Northwest shall be for the equal benefit, protection and security of the owners of any and all of the Electric Revenue Bonds and the issuer of any related Credit Facility where the obligation of Energy Northwest to reimburse such issuer is a Parity Reimbursement Obligation, each of which, regardless of time or times of maturity or due dates, shall be of equal rank without preference, priority or distinction of the Electric Revenue Bonds over any other thereof except as expressly provided in or permitted by the Electric Revenue Bond Resolutions.

Authorization of Bonds (Section 201)

The Project 1 Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Project No. 1 Electric Revenue Bonds," the Columbia Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Columbia Electric Revenue Bonds," and the Project 3 Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Project No. 3 Electric Revenue Bonds."

The Electric Revenue Bonds may be issued under each Electric Revenue Bond Resolution from time to time in series, which may consist of two or more subseries, pursuant and subject to the terms, conditions and limitations of the Electric Revenue Bond Resolutions and any Supplemental Electric Revenue Bond Resolutions providing for the issuance of Electric Revenue Bonds, in such amounts as may be determined by Energy Northwest, for one or more of the following purposes: (i) refunding any Outstanding Prior Lien Bond, any Outstanding Electric Revenue Bond or any Outstanding Subordinate Lien Obligation; (ii) the payment, or reimbursement of Energy Northwest for the payment, of the costs of the acquisition, construction or installation of additional facilities or modifications to the related Project in compliance with the order or decision of any State or Federal agency or authority having competent jurisdiction; (iii) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of making renewals, repairs, replacements, improvements or betterments to the related Project, including costs associated with the upgrading of the output capacity of the related Project, including expenses incurred in connection with the upgrading of any operating license in connection therewith; (iv) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of capital additions, improvements or betterments to the related Project necessary to achieve design capability; (v) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of (1) decommissioning the related Project or (2) restoring the site of the related Project, in compliance with applicable Federal or State law or any order or decision of any State or Federal agency or authority having competent jurisdiction; (vi) payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of purchasing fuel for the related Project; (vii) providing funds for deposit into the Reserve Accounts or any other reserves established by any Supplemental Electric Revenue Bond Resolution for the payment of the principal of or interest on the Series of Electric Revenue Bonds authorized thereby and paying the costs incident to the issuance of such Series of Electric Revenue Bonds; and (viii) the payment, or the reimbursement of Energy Northwest for the payment, of the costs of any other purpose permitted by law.

Pledge Effected by the Electric Revenue Bond Resolutions (Section 202)

Energy Northwest pledges for the payment of the principal or redemption price of and interest on the Electric Revenue Bonds in accordance with their terms and the provisions of the Electric Revenue Bond Resolutions (i) the proceeds of the sale of the Electric Revenue Bonds pending application thereof in accordance with the provisions of the applicable Electric Revenue Bond Resolution or of any applicable Supplemental Electric Revenue Bond Resolution, (ii) subject to the provisions of each Electric Revenue Bond Resolution, all revenues, and (iii) the Debt Service Fund established by each Electric Revenue Bond Resolution, including the investments, if any, therein; provided, however, that, subject to each Electric Revenue Bond Resolution, amounts on deposit to the credit of any Reserve Account in the Debt Service Funds are pledged only to the Series of Electric Revenue Bonds for which such Reserve Account was established pursuant to the Supplemental Electric Revenue Bond Resolutions authorizing such Series and may be applied only to pay the principal or redemption price, if any, of and interest on the Electric Revenue Bonds of such Series.

Except as may be otherwise provided in the Electric Revenue Bond Resolutions or in the Supplemental Electric Revenue Bond Resolutions authorizing a Series of Electric Revenue Bonds, the Electric Revenue Bonds of each such Series shall be equally and ratably payable and secured under the related Electric Revenue Bond Resolution without priority by reason of the date of adoption of the Supplemental Electric Revenue Bond Resolutions providing for their issuance or by reason of their Series or subseries, number or date, date of issue, execution, authentication or sale thereof, or otherwise.

The revenues and other moneys pledged and received by Energy Northwest shall immediately be subject to the lien of the pledge made by Energy Northwest under each Supplemental Electric Revenue Bond Resolution without any physical delivery or further act, and the lien of the pledge shall be valid and binding as against any parties having claims of any kind in tort, contract or otherwise against Energy Northwest, irrespective of whether such parties have notice thereof.

Refunding Bonds (Section 204)

All Electric Revenue Bonds issued to refund Outstanding Electric Revenue Bonds shall be authenticated and delivered by the Trustee only upon receipt by it, in addition to other documents required by the Electric Revenue Bond Resolutions (and in addition to further documents required by the provisions of any Supplemental Electric Revenue Bond Resolutions), of:

(i) irrevocable instructions to the Trustee, satisfactory to it, to give due notice of redemption of all the Electric Revenue Bonds to be redeemed on a redemption date or dates specified in such instructions;

(ii) if the Electric Revenue Bonds to be refunded are not to be redeemed within the next succeeding 90 days, irrevocable instructions to the Trustee, satisfactory to it, to give due notice of any refunding of such Electric Revenue Bonds on a specified date prior to their maturity, as provided in Article VI of each Electric Revenue Bond Resolution or in the Supplemental Electric Revenue Bond Resolution which authorized such Electric Revenue Bonds to be refunded, and Section 1101 of each Electric Revenue Bond Resolution;

(iii) either (A) moneys (which may include all or a portion of the proceeds of the refunding Electric Revenue Bonds to be issued) in an amount sufficient to effect payment of the principal or the redemption price of the Electric Revenue Bonds to be refunded, together with accrued interest on such Electric Revenue Bonds to the maturity or redemption date thereof, as the case may be, or (B) Defeasance Obligations in such principal amounts, of such maturities, bearing such interest and otherwise having such terms and qualifications and any moneys, as shall be necessary to comply with the provisions of Section 1101 of each Electric Revenue Bond Resolution, which Defeasance Obligations and moneys shall be held in trust and used only as provided in Section 1101 of each Electric Revenue Bond Resolution; and

(iv) such further documents and moneys as are required by the provisions of each Electric Revenue Bond Resolution or any Electric Revenue Bond Supplemental Resolutions.

In addition, all refunding Electric Revenue Bonds of a Series issued to refund outstanding Prior Lien Bonds shall be authenticated and delivered by the Trustee, upon receipt by the Trustee, in addition to other documents required by the Electric Revenue Bond Resolutions, of evidence satisfactory to it that:

(i) irrevocable instructions have been delivered to the Prior Lien Bond Fund Trustee to give due notice of payment or redemption of all the Project 1, Columbia or Project 3 Prior Lien Bonds to be redeemed prior to their respective maturity dates on the date specified in such instructions, all in accordance with either Resolution Nos. 769, 640 or 775, as the case may be; and

(ii) such further documents and moneys as are required by the provisions of the applicable Electric Revenue Bond Resolution or any Electric Revenue Bond Supplemental Resolution.

Subordinate Obligations (Section 205)

Nothing contained in the Electric Revenue Bond Resolutions prohibits or prevents Energy Northwest from authorizing and issuing bonds, notes, certificates, warrants or other evidences of any indebtedness for any purpose relating to the Net Billed Projects payable as to principal and interest from the revenues subject and subordinate to the deposits and credits required to be made to the funds established under the Electric Revenue Bond Resolutions or from securing such bonds, notes, certificates, warrants or other evidences of indebtedness and the payment thereof by a lien and pledge on the revenues junior and inferior to the lien and the pledge on the revenues created by either Resolution Nos. 769, 640 or 775, as the case may be, and created by the Electric Revenue Bond Resolutions.

Credit Facilities (Section 208)

Electric Revenue Bond Supplemental Resolutions providing for the issuance of a Series of Electric Revenue Bonds may provide that Energy Northwest obtain or cause to be obtained Credit Facilities providing for payment of all or a portion of the purchase price or Principal Installment or Redemption Price of, or interest due or to become due on specified Electric Revenue Bonds of such Series or any Subseries thereof, or providing for the purchase of such Electric Revenue Bonds or a portion thereof by the issuer of the Credit Facilities, or providing, in whole or in part, for the funding of the Reserve Accounts pursuant to Section 505 of each Electric Revenue Bond Resolution, provided such Credit Facility is a Reserve Guaranty. In connection therewith, Energy Northwest may enter into agreements with the issuers of the Credit Facility to provide for the terms and conditions thereof, including the security, if any, to be provided to such issuers.

Energy Northwest may secure the applicable Credit Facility by an agreement providing for the purchase of the Electric Revenue Bonds secured thereby with such adjustments to the rate of interest, method of determining interest, maturity, or redemption provisions as specified in the Supplemental Electric Revenue Bond Resolutions. Interest with respect to any Series of Electric Revenue Bonds so secured shall be calculated for purposes of the Reserve Account Requirement for such Series by using the actual rate of interest or, if applicable, the Certified Interest Rate on the Electric Revenue Bonds prior to adjustment under such agreement. Energy Northwest may also agree to reimburse directly the issuers of the Credit Facilities for any amounts paid thereunder together with interest thereon. Energy Northwest may provide that any such obligations to reimburse shall be Parity Reimbursement Obligations. In addition, Energy Northwest may, in connection with any such Credit Facility, agree to pay the fees and expenses of, and other amounts payable to, the issuers of such Credit Facilities, the payment of which may be secured by pledges of revenues, funds and other moneys pledged pursuant to the Electric Revenue Bond Resolutions on a parity with the pledges created by the Electric Revenue Bond Resolutions.

The Bond Fund (Section 501)

The Bond Fund created for the related Series of Prior Lien Bonds shall be continued for so long as any related Prior Lien Bonds remain Outstanding. As soon as practicable after the date on which the Prior Lien Bonds are no longer Outstanding, Energy Northwest will direct, in writing, the Bond Fund Trustee under the related Prior Lien Resolutions to deliver forthwith all moneys and securities held in the Bond Fund, except for amounts, if any, required to be held by said Bond Fund Trustee to provide for the payment of the principal (including sinking fund installments) of premium, if any, and interest on the Prior Lien Bonds and expenses of the Bond Fund Trustee, to Energy Northwest, who will deposit such moneys and securities in the General Revenue Fund.

Establishment of Funds (Section 502)

The following special trust funds are established by each Electric Revenue Bond Resolution:

(a) General Revenue Fund, to be held and maintained by Energy Northwest; and

(b) Debt Service Fund, to be held and maintained by the Trustee. The Debt Service Fund shall include a separate Debt Service Account for each Series of Electric Revenue Bonds and a separate subaccount for each subseries of Electric Revenue Bonds issued under each Electric Revenue Bond Resolution and each such Debt Service Account and subaccount shall be designated using the designation of the Series or subseries, if any, to which such Debt Service Account or subaccount relates.

The existence of such funds shall be continued for so long as any Electric Revenue Bonds remain outstanding. Energy Northwest may establish pursuant to Supplemental Electric Revenue Bond Resolutions authorizing the issuance of Electric Revenue Bonds, additional funds, accounts and subaccounts for the purposes designated in such Supplemental Electric Revenue Bond Resolutions.

Disposition of Revenues (Section 503)

So long as the Project 1, Columbia or Project 3 Prior Lien Bonds remain outstanding, Energy Northwest has obligated and bound itself irrevocably to pay, after first providing for all required deposits and payments under the respective Prior Lien Resolutions to each trustee or paying agent of Parity Debt (including the Trustee), and to each person entitled thereto in the event there is no trustee or paying agent for such Parity Debt, the respective stated amounts scheduled to be paid on such Parity Debt in accordance with its terms without preference or priority of any Parity Debt over any other Parity Debt, including the deposits into the Debt Service Accounts or subaccounts, as the case may be, hereinafter specified. In the event that Energy Northwest has insufficient funds to make all payments required pursuant to the preceding sentence, Energy Northwest shall pay to each trustee or paying agent of Parity Debt (including the Trustee) and to each person entitled thereto, as applicable, its pro rata share of the amounts available to Energy Northwest for such payments. With respect to payments to be made to the Trustee, Energy Northwest shall set aside and pay (i) on or before the 25th day in each month immediately preceding a Payment Date to the Trustee for deposit into the Debt Service Account for each Series, or, in the event a Series consists of two or more Subseries, into each debt service subaccount in the related Debt Service Account, from the revenues theretofore deposited in the Revenue Fund the amount, which, when added to the amount then on deposit in each respective Debt Service Account or subaccount thereof, as appropriate, will make the amount on deposit in each such Debt Service Account, or, with respect to Subseries, each subaccount thereof, equal to the amount of principal scheduled to mature, the amount of each scheduled sinking fund installment required to be paid and the amount of interest due and payable, or if such amount of interest is not known as of such date, the amount reasonably estimated by Energy Northwest to be necessary to pay interest, on the Electric Revenue Bonds of each Series or Subseries on the next succeeding Payment Date, (ii) as and when required, the amounts required to be deposited in the accounts and subaccounts of the Debt Service Fund, and (iii) to the extent not included in clause (i) above, to the issuer of any Credit Facility and the counterparty to any Payment Agreement, and, with respect to any Parity Reimbursement Obligation, the amounts, if any, provided to be so paid pursuant to the related Supplemental Electric Revenue Bond Resolution, in each case, in the amounts, at the times and in the manner provided therein. There shall also be deposited in the Debt Service Fund and any accounts and subaccounts thereof, as and when received by the Trustee, all other amounts required by the Electric Revenue Bond Resolutions to be so deposited.

On and after the date on which there shall be no Prior Lien Bonds outstanding, Energy Northwest covenants and agrees that it will pay into each General Revenue Fund as promptly as practical after receipt thereof all revenues and all other amounts required by the Electric Revenue Bond Resolutions to be so deposited.

General Revenue and Debt Service Funds (Sections 504 and 505)

General Revenue Fund. The amounts on deposit in each General Revenue Fund shall be trust funds in the hands of Energy Northwest and, subject to certain provisions described herein, shall be used and applied as provided in the applicable Electric Revenue Bond Resolution solely for the purpose of paying principal and interest on Parity Debt, the cost of operating and maintaining the related Project and paying all other costs, charges and expenses in connection with the costs of making repairs, renewals, replacements, additions, betterments and improvements to and extensions of the related Project and for purposes of paying all other charges and obligations against said revenues, income, receipts, profits and other moneys of whatever nature now or hereafter imposed thereon by law or contract, to the payment of which for such purposes said revenues and other moneys are pledged, including amounts required to be paid to the issuers of any Credit Facility pursuant to the provisions of any related Supplemental Electric Revenue Bond Resolution.

After the date on which there are no Prior Lien Bonds Outstanding, Energy Northwest shall pay, from the moneys on deposit in each General Revenue Fund, to each trustee or paying agent of Parity Debt (including the Trustee), and to each person entitled thereto in the event there is no trustee or paying agent for such Parity Debt, the respective stated amounts scheduled to be paid on such Parity Debt in accordance with its terms without preference or priority of any Parity Debt over any other Parity Debt, including the deposits into the Debt Service Accounts or subaccounts, as the case may be, hereinafter specified. In the event that the moneys on deposit in the General Revenue Fund shall be insufficient to make all payments required pursuant to the preceding sentence, Energy Northwest shall pay to each trustee or paying agent of Parity Debt and to each person thereof entitled thereto, as applicable, its pro rata share of the amounts on deposit in the General Revenue Fund. With respect to payments to be made to the Trustee, Energy Northwest shall set aside and pay (i) on or before the last Business Day in each month immediately preceding a Payment Date to the Trustee for deposit into the Debt Service Account for each Series, or, in the event a Series consists of two or more Subseries, into each relevant debt service subaccount in the related Debt Service Account, the amount, which, when added to the amount, if any, then on deposit in each respective Debt Service Account or subaccount thereof, as appropriate, will make the amount on deposit in each such Debt Service Account, or, with respect to Subseries, each subaccount thereof, equal to the amount of principal scheduled to mature, the amount of each sinking fund installment required to be paid, and the amount of interest due and payable, or, if such amount of interest is not known as of such date, the amount reasonably estimated by Energy Northwest to be necessary to pay interest on the Electric Revenue Bonds of each Series or Subseries on the next succeeding Payment Date, (ii) as and when required, the amounts required to be deposited in the accounts and subaccounts of the Debt Service Fund, and (iii) to the extent not included in clause (i) above, to the issuer of any Credit Facility and the counterparty to any Payment Agreement, and, with respect to any Parity Reimbursement Obligation, the amounts, if any, required to be so paid pursuant to the provisions of the related Supplemental Electric Revenue Bond Resolution, in each case, in the amounts, at the times and in the manner provided therein. There shall also be deposited in the Debt Service Fund and any accounts and subaccounts thereof, as and when received by the Trustee, all other amounts required by the applicable Electric Revenue Bond Resolution to be so deposited.

Debt Service Fund. The Trustee shall, for each Series or Subseries of Electric Revenue Bonds Outstanding, pay from the moneys on deposit in each relevant Debt Service Account or subaccount of each Debt Service Fund (i) the amounts required for the payment of the principal, if any, due on each Payment Date, (ii) the amount required for the payment of interest due on each Payment Date, (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, (iv) on any redemption date or date of purchase, the amounts required for the payment of accrued interest on Electric Revenue Bonds to be redeemed or purchased on such date unless the payment of such accrued interest shall be otherwise provided, and (v) at the times and in the manner provided in the related Supplemental Electric Revenue Bond Resolution and the agreements between Energy Northwest and any issuer of a Credit Facility or counterparty to any Payment Agreement, to the issuer of any Credit Facility and the counterparty to any Payment Agreement, and, with respect to any Parity Reimbursement Obligation, the amounts provided to be so paid.

Unless otherwise provided for a Series of Electric Revenue Bonds in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, Energy Northwest may, prior to the forty-fifth day preceding the due date of any sinking fund installment purchase Electric Revenue Bonds of the Series or Subseries, as the case may be, and maturity for which such sinking fund installment was established, at prices (including any brokerage and other charges) not exceeding the redemption price payable for such Electric Revenue Bonds when such Electric Revenue Bonds are redeemable by application of such sinking fund installment plus unpaid interest accrued to the date of purchase, such purchases to be made by the Trustee as directed in writing by an authorized officer of Energy Northwest.

Unless otherwise provided for a Series of Electric Revenue Bonds in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, upon the purchase or redemption (other than by application of sinking fund installments) of any Electric Revenue Bond, an amount equal to the principal amount of the Electric Revenue Bond so purchased or redeemed shall be credited toward the sinking fund installments thereafter to become due as directed in writing by an authorized officer of Energy Northwest.

Energy Northwest may, at its option, in lieu of depositing all or any part of the sinking fund installments into each relevant Debt Service Account or subaccount thereof of each Debt Service Fund, furnish the Trustee with a Certificate of an authorized officer stating that Energy Northwest has purchased for cancellation term bonds of a Series or Subseries of Electric Revenue Bonds in the principal amount, and bearing the numbers, specified therein, and that said term bonds have not been previously included in any such Certificate; and thereupon the sinking fund installments with respect to the term bonds of such Series or subseries, as the case may be, may be reduced by the principal amount of such term bonds canceled, as provided by such Certificate.

Unless otherwise provided for a Series of Electric Revenue Bonds or subseries thereof, as the case may be, in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, as soon as practicable after the forty-fifth day preceding the due date of any such sinking fund installment, the Trustee shall proceed to call for redemption, pursuant to Article IV of each Electric Revenue Bond Resolution or the applicable Supplemental Electric Revenue Bond Resolutions, as the case may be, on such due date, Electric Revenue Bonds of the Series or subseries, as the case may be, and maturity for which such sinking fund installment was established in such amount as shall be necessary to complete the retirement of the principal amount specified for such sinking fund installment of the Electric Revenue Bonds of such Series or subseries, as the case may be, and maturity. The Trustee shall so call such Electric Revenue Bonds for redemption whether or not it then has moneys in each Debt Service Account or subaccount thereof of each Debt Service Fund established for such Series or subseries, as the case may be, sufficient to pay the applicable redemption price thereof on the redemption date. The Trustee shall apply to the redemption of the Electric Revenue Bonds on each such redemption date, the amount required for the redemption of such Electric Revenue Bonds.

Bond Proceeds Funds (Section 507)

The Supplemental Electric Revenue Bond Resolution providing for the issuance of any Series of Electric Revenue Bonds (exclusive of Refunding Bonds) will create and establish one or more special trust funds into which the proceeds of such Series of Electric Revenue Bonds will be deposited and from which such proceeds will be disbursed to pay the Costs of the Authorized Purpose or Purposes for which such Series of Electric Revenue Bonds were issued (unless such Supplemental Electric Revenue Bond Resolution will provide for the deposit of such proceeds in one or more of such funds theretofore created and established). Each such fund (a "Bond Proceeds Fund") will be held in trust by Energy Northwest, for the benefit of the owners of the Electric Revenue Bonds pending application thereof in accordance with the terms of the related Supplemental Electric Revenue Bond Resolution. Payments from Bond Proceeds Fund will be as specified in the Supplemental Electric Revenue Bond Resolution authorizing the issuance of a related Series of Electric Revenue Bonds.

Amounts on deposit in any Bond Proceeds Fund, pending their application as provided in the Supplemental Electric Revenue Bond Resolution creating such Bond Proceeds Fund, will be subject to a prior and paramount lien and charge in favor of the owners of the Electric Revenue Bonds, and the owners of the Electric Revenue Bonds will have a valid claim on such moneys for the further security of the Electric Revenue Bonds until paid out or transferred as herein provided.

Investment of Funds (Section 508)

Moneys held in each Debt Service Fund shall, to the fullest extent practicable and reasonable, be invested and reinvested by the Trustee upon request of Energy Northwest (promptly confirmed in writing) solely in Investment Securities which shall mature or be subject to redemption at the option of the owner thereof on or prior to the respective dates when the moneys therein will be required for the purposes intended. However, moneys in each Reserve Account in each Debt Service Fund not required for immediate disbursement for the purpose for which said Account is created shall, to the fullest extent practicable and reasonable, be invested and reinvested by the Trustee at the direction of Energy Northwest (promptly confirmed in writing) solely in, and obligations credited to each Reserve Account shall be, Investment Securities which, unless otherwise provided in the related Supplemental Electric Revenue Bond Resolution, shall mature or be subject to redemption at the option of the owner thereof on or prior to the last maturity date of the related Series of Electric Revenue Bonds. The Trustee shall not be liable for any depreciation in value of any such investments. For the purpose of Section 508 of the Electric Revenue Bond Resolutions, the term "Investment Securities" shall be limited to obligations described in clauses (i) and (v) of the definition of Investment Securities.

Nothing in the Electric Revenue Bond Resolutions shall prevent any Investment Securities acquired as investments of funds held thereunder from being issued or held in book-entry form.

Valuation or Sale of Investments (Section 509)

Investment Securities in any fund or account created under the provisions of each Electric Revenue Bond Resolution shall be deemed at all times to be part of such fund or account and any profit realized from the liquidation of such investment shall be credited to such fund or account and any loss resulting from liquidation of such investment shall be charged to such fund or account. So long as the Project 1, Columbia or Project 3 Prior Lien Bonds shall remain Outstanding, any net profits remaining after accumulating the sum of all profits realized and losses suffered from the liquidation of such investments in any fund or account shall be retained in the related Debt Service Accounts (or subaccounts) of each Debt Service Fund, unless otherwise provided in Supplemental Electric Revenue Bond Resolutions authorizing Series of Electric Revenue Bonds; provided, however, that if the money and value of investments in any Reserve Account in each Debt Service Fund shall exceed the applicable Reserve Account Requirement for the Series of Electric Revenue Bonds for which such Reserve Account was established, the amount of such excess shall be transferred by the Trustee, without further authorization or direction by Energy Northwest to each Debt Service Account established for such Series, unless otherwise provided in Supplemental Electric Revenue Bond Resolutions authorizing such Series of Electric Revenue Bonds. After the date on which there shall be no Project 1, Columbia or Project 3 Prior Lien Bonds outstanding, any such net profits or excess shall be transferred by the Trustee, without further authorization or direction by Energy Northwest, or paid to, or retained in, each General Revenue Fund.

In computing the amount in any fund or account, Investment Securities therein shall be valued at cost or, if purchased at a premium or discount, at their amortized value. Any such computation shall include accrued interest on the Investment Securities paid as part of the purchase price thereof and not repaid. Such computation shall be made annually on June 30th for all funds and accounts established pursuant to the Electric Revenue Bond Resolutions and at such other times as Energy Northwest shall determine or as may be required by the Electric Revenue Bond Resolutions.

Except as otherwise provided in the Electric Revenue Bond Resolutions, the Trustee, as directed by an authorized officer of Energy Northwest (promptly confirmed in writing), shall use its best efforts to sell at the best price obtainable, or present for redemption, any Investment Securities held by the Trustee in any fund or account whenever it shall be necessary, and upon oral request (promptly confirmed in writing) from an authorized officer of Energy Northwest in order to provide moneys to meet any payment or transfer from such fund or account. The Trustee shall not be liable or responsible for any loss resulting from any such investment, sale, liquidation or presentation for investment made in the manner provided above.

Subject to the foregoing limitations, any moneys held by Energy Northwest or the Trustee under a particular Electric Revenue Bond Resolution may be pooled in order to make any purchase of Investment Securities or deposit of moneys held under such Electric Revenue Bond Resolution, which purchases or deposits are otherwise permitted thereunder; provided, however, that Energy Northwest and the Trustee shall at all times keep accurate and complete records of the Investment Securities so purchased and deposits so made in sufficient detail as will permit the application of such Investment Securities and deposits, and the proceeds thereof, solely for the purposes, at the times and in the manner provided in each Electric Revenue Bond Resolution.

Qualifications and Appointment of Trustee; Resignation or Removal Thereof; Successor Thereto (Section 601)

In the Supplemental Electric Revenue Bond Resolution providing for the issuance of the initial Series of Electric Revenue Bonds, Energy Northwest shall appoint a Trustee (the "Trustee") to hold and administer the Funds and Accounts created and established in each Electric Revenue Bond Resolution. The Trustee will be a commercial bank with trust powers or trust company with capital stock, surplus and undivided profits aggregating in excess of $50,000,000. The Trustee may be removed at the request of or upon the affirmative vote of (i) the owners of a majority of the principal amount of Electric Revenue Bonds outstanding, or (ii) a majority of the members of the Executive Board of Energy Northwest, provided, however, that the Trustee may not be removed pursuant to the preceding clause (ii) upon the occurrence of an Event of Default or while such an Event of Default shall be continuing: provided further, that any removal will not take effect until the appointment of a successor and the acceptance by such successor in accordance with each Electric Revenue Bond Resolution.

In the event of the removal pursuant to clause (i) of the preceding sentence, resignation, disability or refusal to act of the Trustee, a successor may be appointed by the owners of a majority of the principal amount of Electric Revenue Bonds outstanding, excluding any Electric Revenue Bonds held by or for the account of Energy Northwest, and such successor shall have all the powers and obligations of the Trustee under each Electric Revenue Bond Resolution theretofore vested in its predecessor; provided, that unless a successor Trustee has been appointed by the owners of Electric Revenue Bonds as aforesaid, Energy Northwest by a duly executed written instrument signed by a majority of the members of the Executive Board will concurrently appoint a Trustee to fill such vacancy until a successor Trustee will be appointed by the owners of Electric Revenue Bonds as authorized in this paragraph. Any successor Trustee appointed by Energy Northwest pursuant to this paragraph will, immediately and without further act, be superseded by a Trustee so appointed by the owners of Electric Revenue Bonds.

In the event of the removal of the Trustee pursuant to clause (ii) above, Energy Northwest will appoint a successor Trustee.

Any Trustee may resign at any time by giving not less than 180 days' notice to Energy Northwest in writing and to the Bondholders by publishing a notice of resignation in an Authorized Newspaper once within 10 days after the giving of such notice to the Energy Northwest; provided, however, that such resignation shall not take effect until the appointment of a successor and the acceptance of such successor in accordance with this Resolution.

The resigning Trustee, if within 50 days after the publication of notice of its resignation no successor Trustee has been appointed and accepted such appointment, may petition any court of competent jurisdiction for the appointment of a successor Trustee, or any owner of a Bond who has been an owner of a Bond for at least six months may, on behalf of such owner and others similarly situated, petition any such court for the appointment of a successor Trustee. Such court may thereupon, after such notice, if any, appoint a successor Trustee having the qualifications required hereby.

In case at any time any of the following shall occur: (i) any Trustee ceases to be eligible in accordance with the provisions of each Electric Revenue Bond Resolution and fails to resign after written request therefor has been given to such Trustee by Energy Northwest or by any owner of a Bond who has been a bona fide owner of a Bond for at least six months, or (ii) any Trustee becomes incapable of acting, or is adjudged a bankrupt or insolvent, or a receiver of such Trustee or of its property is appointed, or any public officer takes charge or control of such Trustee or of its property or affairs for the purpose of rehabilitation, conservation or liquidation, or (iii) any Trustee neglects or fails in the performance of its duties under each Electric Revenue Bond Resolution, then, in any such case, Energy Northwest may remove such Trustee by an instrument in writing signed by an Authorized Officer or any such owner of a Bond may, on behalf of himself and all others similarly situated, petition any court of competent jurisdiction for the removal of such Trustee. Such court may thereupon, after such notice, if any, as it may deem proper and prescribe and as may be required by law, remove such Trustee.

Any successor Trustee shall meet the qualifications of each Electric Revenue Bond Resolution. Such successor Trustee will execute, acknowledge and deliver to its predecessor, and also to Energy Northwest, an instrument in writing accepting such appointment under each Electric Revenue Bond Resolution, and thereupon such successor Trustee, without any further acts, deed or conveyance, shall become fully vested with all the rights, powers, trusts, duties and obligations of its predecessor in trust under each Electric Revenue Bond Resolution, with like effect as if originally named as Trustee; but such predecessor will, nevertheless, on the written request of Energy Northwest or such successor Trustee, execute and deliver an instrument transferring to such successor Trustee all rights, powers, trusts, duties and obligations of such predecessor in trust under each Electric Revenue Bond Resolution and will deliver all moneys held by it to such successor Trustee, together with an accounting of funds held by it under each Electric Revenue Bond Resolution. The successor Trustee will have no responsibility for the acts of the predecessor Trustee.

Upon acceptance of appointment by the successor Trustee, as provided in this Section, Energy Northwest will publish notice of the succession of such Trustee to the trusts hereunder at least once in an Authorized Newspaper. If Energy Northwest fails to publish such notice, within 10 days after acceptance of appointment by the successor Trustee, the successor Trustee will cause such notice to be published at the expense of Energy Northwest.

Any corporation into which a Trustee may be merged or with which it may be consolidated, or any corporation resulting from any merger or consolidation to which a Trustee is a party, or any corporation to which a Trustee may sell or transfer all or substantially all of its corporate trust business, will be the successor Trustee under each Electric Revenue Bond Resolution without the execution or filing of any paper or any further act on the part of the parties to each Electric Revenue Bond Resolution; provided such corporation meets the qualifications of each Electric Revenue Bond Resolution.

Certain Covenants (Article VII)

Energy Northwest covenants and agrees with the purchasers and owners of all Electric Revenue Bonds issued pursuant to the Electric Revenue Bond Resolution to the following:

Compliance with Prior Lien Resolutions. So long as any of the Project 1 Prior Lien Bonds, the Columbia Prior Lien Bonds or the Project 3 Prior Lien Bonds are Outstanding, Energy Northwest shall comply in all respects with each of the provisions, covenants and agreements of or contained in Resolution Nos. 769, 640 and 775, respectively.

Concerning the Agreements and Prior Lien Resolutions. So long as any of the Electric Revenue Bonds are Outstanding, Energy Northwest will not (i) voluntarily consent to or permit any rescission of or consent to any amendment to or otherwise take any action under or in connection with any of the Net Billing Agreements which will reduce the payments provided for therein or which will in any manner impair or adversely affect the rights of Energy Northwest or of the owners from time to time of the Electric Revenue Bonds, or (ii) voluntarily consent to or permit any rescission of or consent to any amendment to or modification of or otherwise take any action under or in connection with, each Project Agreement in the case of Columbia, each Assignment Agreement, each Property Disposition Agreement or each 1989 Letter Agreement which will in any manner impair or adversely affect the rights of Energy Northwest or of the owners from time to time of the Electric Revenue Bonds; and Energy Northwest shall perform all of its obligations under said Agreements and shall take such actions and proceedings from time to time as shall be necessary to protect and safeguard the security for the payment of the Electric Revenue Bonds afforded by the provisions of said Agreements. Energy Northwest will not, so long as any Project 1, Columbia or Project 3 Prior Lien Bonds remain Outstanding, consent to or agree to any change, amendment or modification of the Prior Lien Resolutions, respectively, which would in any way or manner prejudice or affect adversely the rights or interests of the owners of the Electric Revenue Bonds.

Encumbrance or Disposition of Project Properties; Termination of Projects. On and after the date on which the Prior Lien Bonds are no longer Outstanding, Energy Northwest will not sell, mortgage, lease or otherwise dispose of any properties of the related Project, or permit the sale, mortgage, lease or other disposition thereof, except as provided below.

> (i) Energy Northwest may sell, lease or otherwise dispose of all or any portion of the works, plants and facilities of a Project and any real and personal property comprising a part thereof which is unserviceable, inadequate, obsolete, worn-out or unfit to be used or no longer required for use in connection with the operation of a Project, provided, however, that if the original costs of the properties so to be disposed of was in excess of $5,000,000, an Engineer shall first certify that the properties to be disposed of are unserviceable, inadequate, obsolete, worn-out or unfit to be used or no longer required for use in connection with the operations of a Project; provided, however, no such certification shall be required if such sale or other disposition takes place after a Project has been terminated. Money received by Energy Northwest as the proceeds of any such sale, lease or other disposition of all or any portion of the properties of a Project shall be used for the purchase or redemption of Electric Revenue Bonds and thereafter, any excess shall be deposited in the respective General Revenue Funds; provided, however, that if such sale, lease or other disposition of all or any portion of the properties of a Project is in connection with the replacement of such properties, all moneys received from such partial disposition of property may be transferred to the respective General Revenue Funds.
>
> (ii) Energy Northwest may sell, lease or otherwise dispose of fuel for a price not less than the lesser of the cost to Energy Northwest thereof or the fair market value thereof at the time of such sale, lease or other disposition; provided, that any moneys received by Energy Northwest as proceeds of any such sale, lease or purchase shall be either transferred to the respective General Revenue Funds or used for the purchase or redemption of Electric Revenue Bonds.
>
> (iii) In the event that the ownership of the properties of a Project or any part thereof shall be transferred from Energy Northwest through the operation of law, any moneys received by Energy Northwest as a result of any such transfer shall be used for the purchase or redemption of Electric Revenue Bonds and thereafter, any excess shall be deposited in the respective General Revenue Funds.
>
> (iv) Energy Northwest may terminate a Project at any time. Any moneys received by Energy Northwest from the disposition of the properties of a Project so terminated may be applied to the payment of the cost of decommissioning such Project including the cost of restoring the site thereof, and any amounts so received not required to pay such costs shall be applied as provided in paragraph (iii) above or in each Electric Revenue Bond Resolution.

Nothing contained in the Electric Revenue Bond Resolutions shall be construed to prevent Energy Northwest from constructing as a separate utility system any additional generating unit or units on or near the site of any Project, and using facilities of a Project in connection with the construction or operation therewith without compensation therefor; provided, however, that an Engineer shall certify to Energy Northwest and the Trustee that such use will not adversely affect the operations of the applicable Project or interfere with the performance by Energy Northwest of its obligations under the Electric Revenue Bond Resolutions; and provided further, however, that any compensation received by Energy Northwest on account of any such use shall be paid into the respective General Revenue Funds.

Notwithstanding the provisions of subsections (i) through (iv) above, moneys received by Energy Northwest as a result of any sale, lease, transfer or other disposition specified in such subsections and which are in excess of the amounts required for decommissioning and site restoration costs may be transferred to such funds or accounts determined by Energy Northwest or used to purchase or redeem Electric Revenue Bonds.

Insurance. Energy Northwest shall, to the extent available at reasonable cost with responsible insurers, keep, or cause to be kept, the works, plants and facilities comprising the properties of the related Project and the operation thereof insured, with policies payable to Energy Northwest for the benefit of Energy Northwest, the Participants and Bonneville, as their interests may appear, against risks of direct physical loss, damage to or destruction of such properties or any part thereof, and against accidents, casualties, or negligence, including liability insurance and employer's liability, at least to the extent that similar insurance is usually carried by electric utilities operating like properties, and such other insurance as may be agreed upon by the parties to the Columbia Project Agreement. To the extent such insurance is being maintained by Energy Northwest pursuant to the Prior Lien Resolutions, no such insurance need be maintained under the related Electric Revenue Bond Resolution. In the case of loss, including loss of revenue, caused by suspension or interruption of generation or transmission of power and energy by a Project, the proceeds of any insurance policy or policies covering such loss received by Energy Northwest, prior to the retirement of the related Prior Lien Bonds, shall be paid into the related Revenue Fund, and thereafter, shall be paid into the related General Revenue Fund. Within 60 days after the end of each fiscal year, Energy Northwest shall file, or cause to be filed, with the Trustee a certificate of an Engineer describing in reasonable detail the insurance on the Projects then in effect pursuant to the requirements of the related Electric Revenue Bond Resolution and stating whether, in its opinion, such insurance then in effect reasonably complies with the provisions hereof. Prior to the retirement of the Project 1, Columbia or Project 3 Prior Lien Bonds, the filing of such a certificate pursuant to the related Prior Lien Resolutions shall satisfy the requirement of the preceding sentence.

Books of Account; Annual Audit. Energy Northwest shall keep proper books of account for each Project, showing as a separate utility system the accounts of each Project in accordance with the rules and regulations prescribed by any governmental agency authorized to prescribe such rules, including the Division of Municipal Corporations of the State Auditor's office of the State of Washington, or other state department or agency succeeding to such duties of the State Auditor's office, and in accordance with the Uniform System of Accounts prescribed from time to time by the Federal Energy and Regulatory Commission, or any successor federal agency having jurisdiction over electric public utility companies owning and operating properties similar to each Project, whether or not Energy Northwest is required by law to use such system of accounts. Within 120 days after the end of each fiscal year, Energy Northwest shall cause such books of account to be audited by independent certified public accountants of national reputation licensed, registered or entitled to practice and practicing as such under the laws of the State of Washington who, or each of whom, is in fact independent and does not have any interest, direct or indirect, in any contract with Energy Northwest other than his contract of employment to audit books of account of Energy Northwest, and who is not connected with Energy Northwest as an officer or employee of Energy Northwest. A copy of each audit report, annual balance sheet and income and expense statement showing in reasonable detail the financial condition of each Project as of the close of each fiscal year and summarizing in reasonable detail the income and expenses for such year, including the transactions relating to the funds and accounts and the amounts expended for maintenance and for renewals, replacements and gross capital additions to each Project shall be filed promptly with the Trustee and sent to any Bondholder filing with Energy Northwest a written request for a copy thereof. In connection with each annual audit the independent auditor will prepare a report that states nothing came to their attention that caused them to believe that Energy Northwest failed to comply with the terms, covenants, provisions, or conditions of the Electric Revenue Bond Resolution and each Supplemental Electric Revenue Bond Resolution insofar as they relate to accounting matters or, if not in compliance therewith, the details of such failure to comply.

Consulting Engineer. So long as Energy Northwest owns and operates the Columbia Generating Station, Energy Northwest will retain on its staff one or more qualified engineers and hire an independent engineering firm when and as deemed necessary or advisable to provide immediate and continuous engineering counsel with respect to the Columbia Generating Station.

Protection of Security; Additional Parity Indebtedness. Energy Northwest is duly authorized under all applicable laws to create and issue the Electric Revenue Bonds and to adopt the Electric Revenue Bond Resolutions and to pledge the revenues and other moneys, securities and funds purported to be pledged by the Electric Revenue Bond Resolutions in the manner and to the extent provided in the Electric Revenue Bond Resolutions. The revenues and other moneys, securities and funds so pledged are and will be free and clear of any pledge, lien, charge or encumbrance thereon, or with respect thereto, prior to, or of equal rank with, the pledge created by the Electric Revenue Bond Resolutions, so long as any of the Project 1, Columbia or Project 3 Prior Lien Bonds remain outstanding, except for the lien and pledge of the Prior Lien Resolutions, and all corporate action on the part of Energy Northwest to that end has been duly and validly taken. The Electric Revenue Bonds and the provisions of the Electric Revenue Bond Resolutions are and will be valid and legally enforceable obligations of Energy Northwest in accordance with their terms and the terms of the Electric Revenue Bond Resolutions. Energy Northwest shall at all times, to the extent permitted by law, defend, preserve and protect the pledge of the revenues and other moneys, securities and funds pledged under the Electric Revenue Bond Resolutions and all the rights of the Bondholders under the Electric Revenue Bond Resolutions or any issuer of a Credit Facility pursuant to a Supplemental Electric Revenue Bond Resolution against all claims and demands of all persons whomsoever.

Subject to the provisions of the Prior Lien Resolutions, Energy Northwest will not hereafter create any other special fund or funds for the payment of bonds, warrants or other obligations or issue any bonds, warrants or other obligations payable out of or secured by a pledge of revenues or create any additional obligations which will rank on a parity with or in priority over the pledge and lien of such revenues created under the Electric Revenue Bond Resolutions, except that Energy Northwest may issue bonds, notes or other obligations, under a separate resolution or resolutions, which are payable from or secured by a pledge of the revenues and may create or cause to be created any lien or charge on such revenues, ranking on a parity with the pledge and lien created by the Electric Revenue Bond Resolutions, for any one or more of the purposes provided in the Electric Revenue Bond Resolutions or may create Parity Reimbursement Obligations. However, Energy Northwest shall not issue any such additional bonds, notes or other obligations or create Parity Reimbursement Obligations unless, on the date of issue of such bonds, the certain contracts or agreements described in the Electric Revenue Bond Resolutions are in full force and effect and no Event of Default under the Electric Revenue Bond Resolutions shall have occurred and be continuing.

Further Assurances. Energy Northwest will at any and all times, insofar as it may be authorized so to do by law, pass, make, do, execute, acknowledge and deliver all and every such further resolutions, acts, deeds, conveyances, assignments, transfers and assurances as may be necessary or desirable for the better assuring, conveying, granting, assigning and confirming all and singular the rights, revenues and other funds pledged or assigned to the payment of the obligations issued by Energy Northwest payable from the revenues of each Project, including the Electric Revenue Bonds or intended so to be, or which Energy Northwest may hereafter become bound to pledge or assign.

Tax Covenants. Energy Northwest covenants with the owners from time to time of the Electric Revenue Bonds that (i) throughout the term of the Electric Revenue Bonds, and (ii) through the date that the final rebate, if any, must be made to the United States in accordance with Section 148 of the Code it will comply with the provisions of Sections 103 and 141 through 150 of the Code and all regulations proposed and promulgated thereunder that must be satisfied in order that interest on the Electric Revenue Bonds shall be and continue to be excluded from gross income for federal income tax purposes.

Energy Northwest shall not permit at any time or times any of the proceeds of the Electric Revenue Bonds or any other funds of Energy Northwest to be used directly or indirectly to acquire any securities or obligations the acquisition of which would cause any Electric Revenue Bond to be an "arbitrage bond" as defined in Section 148 of the Code, or any successor provision of law.

Energy Northwest shall not permit at any time or times any proceeds of any Series of Electric Revenue Bonds or any other funds of Energy Northwest to be used, directly or indirectly, in a manner which would result in the exclusion of any Electric Revenue Bond from the treatment afforded by Section 103(a) of the Code.

Anything contained in the three preceding paragraphs to the contrary notwithstanding, Energy Northwest reserves the right to issue, from time to time, one or more Series of Electric Revenue Bonds the interest on which is includable in the gross income of the recipient thereof for federal income tax purposes ("Taxable Bonds"), provided that the issuance of any such Series of Taxable Bonds does not adversely affect the federal tax exemption of the interest on any other Series of Electric Revenue Bonds.

Events of Default and Remedies (Section 801)

The occurrence of one or more of the following events shall constitute an "Event of Default" under the Electric Revenue Bond Resolution to which such Event of Default relates:

(1) if payment of principal or the redemption price of any related Electric Revenue Bond shall not punctually be made when due and payable, whether at the stated maturity thereof, upon redemption or otherwise;

(2) if payment of the interest on any related Electric Revenue Bond shall not punctually be made when due;

(3) if payment of any related Parity Reimbursement Obligation shall not be punctually made when due;

(4) if Energy Northwest shall fail to duly and punctually perform or observe any other of the covenants, agreements or conditions contained in the applicable Electric Revenue Bond Resolution or in the related Electric Revenue Bonds, on the part of Energy Northwest to be performed (other than the covenant relating to compliance with the respective Prior Lien Resolutions), and such failure shall continue for 90 days after written notice thereof from the Trustee or the owners of not less than 25% of the related Electric Revenue Bonds then outstanding; provided that, if such failure cannot be corrected within such 90 day period, it shall not constitute an Event of Default if corrective action is instituted within such period and diligently pursued until the failure is corrected; and provided further that the exclusion of the covenant relating to compliance with the respective Prior Lien Resolutions, shall not be construed to prevent the Trustee from enforcing any remedy it may have, at law or in equity, for a breach of such covenant;

(5) if an order, judgment, or decree shall be entered by any court of competent jurisdiction, with the consent or acquiescence of Energy Northwest, or if such order, judgment or decree, having been entered without the consent or acquiescence of Energy Northwest, shall not be vacated or set aside or discharged or stayed (or in case

custody or control is assumed by said order, such custody or control shall not otherwise be terminated) within ninety (90) days after the entry thereof, and if appealed, shall not thereafter be vacated or discharged: (i) appointing a receiver, trustee or liquidator for Energy Northwest; or (ii) assuming custody or control of the whole or any substantial part of the applicable Project under the provisions of any law for the relief or aid of debtors; or (iii) approving a petition filed against Energy Northwest under the provisions of 11 USC 901-946, as amended (the "Bankruptcy Act"); or (iv) granting relief to Energy Northwest under any amendment to said Bankruptcy Act, or under any other applicable Bankruptcy Act, which shall give relief substantially similar to that afforded by Chapter IX thereof; and

(6) if Energy Northwest shall (i) admit in writing its inability to pay its debts generally as they become due; or (ii) file a petition in bankruptcy or seeking a composition of indebtedness; or (iii) make an assignment for the benefit of its creditors; or (iv) file a petition or any answer seeking relief under the Bankruptcy Act referred to in the preceding clause, or under any amendment thereto, or under any other applicable bankruptcy act which shall give relief substantially the same as that afforded by Chapter IX of said act; or (v) consent to the appointment of a receiver of the whole or any substantial part of the applicable Project; or (vi) consent to the assumption by any court of competent jurisdiction under the provisions of any other law for the relief or aid of debtors of custody or control of Energy Northwest or of the whole or any substantial part of the applicable Project.

Upon the occurrence of an Event of Default described in the preceding paragraphs, and in each and every such case, so long as such Event of Default shall not have been remedied, unless the principal of all the related Electric Revenue Bonds shall have already become due and payable, the Trustee may, and upon the written request of the owners of not less than 25% of all related Electric Revenue Bonds then outstanding shall, proceed to enforce by such proceedings at law or in equity as it deems most effectual the rights of related Bondholders, and either the Trustee (by notice in writing to Energy Northwest), or the owners of not less than 25% in principal amount of the related Electric Revenue Bonds outstanding (by notice in writing to Energy Northwest and the Trustee), may declare the principal of all the related Electric Revenue Bonds then outstanding, and the interest accrued thereon, to be due and payable immediately, and upon any such declaration the same shall become and be immediately due and payable; provided, however, that so long as any of the Prior Lien Bonds of the related Project remain outstanding, no such declaration may be made unless the principal of all the Prior Lien Bonds of the related Project then outstanding, and the interest accrued thereon, shall have been declared to be due and payable immediately pursuant to Section 12.1 of Resolution No. 769, Section 11.1 of Resolution No. 640 or Section 11.1 of Resolution No. 775, as the case may be. The Trustee shall not be obligated to notify Energy Northwest of its intent to make such a declaration prior to making such declaration. The right of the Trustee or of the owners of not less than 25% in principal amount of the related Electric Revenue Bonds to make any such declaration, however, shall be subject to the condition that if, at any time after such declaration, but before the related Electric Revenue Bonds shall have matured by their terms, all overdue installments of interest upon the related Electric Revenue Bonds, together with interest on such overdue installments of interest to the extent permitted by law and the reasonable and proper charges, expenses and liabilities of the Trustee (including reasonable fees and expenses of counsel to the Trustee), and all other sums then payable by Energy Northwest under the related Electric Revenue Bond Resolution (except the principal of, and interest accrued since the next preceding Payment Date on, the related Electric Revenue Bonds due and payable solely by virtue of such declaration) shall either be paid by or for the account of Energy Northwest or provision satisfactory to the Trustee shall be made for such payment, and all defaults under the related Electric Revenue Bonds or under the related Electric Revenue Bond Resolution (other than the payment of principal and interest due and payable solely by reason of such declaration) shall either be cured or provision shall be made therefor, then and in every such case the owners of a majority in principal amount of the related Electric Revenue Bonds outstanding, by written notice to Energy Northwest and to the Trustee, may rescind such declaration and annul such default in its entirety, or, if the Trustee shall have acted itself, and if there shall not have been theretofore delivered to the Trustee written directions to the contrary by the owners of a majority in principal amount of the related Electric Revenue Bonds then outstanding, then any such declaration shall *ipso facto* be deemed to be annulled, but no such rescission and annulment shall extend to or affect any subsequent default or impair or exhaust any resulting right or power.

Notice to Bondholders of an Event of Default (Section 802)

The Trustee, within 25 days after the occurrence of an Event of Default, shall give to the Bondholders of the related Electric Revenue Bonds, in the manner provided in the applicable Electric Revenue Bond Resolution, notice of all defaults known to the Trustee, and shall give prompt written notice thereof to Energy Northwest, unless such defaults shall have been cured before the giving of such notice.

Accounting and Examination of Records After Default (Section 803)

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, the books of record and account of Energy Northwest relating to the related Project and all other records relating thereto shall at all times be subject to the inspection and use of the Trustee and any persons holding at least 25% of the principal amount of the related Electric Revenue Bonds outstanding and of their respective agents and attorneys or of any committee therefor.

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, Energy Northwest will continue to account, as a trustee of an express trust, for all revenues and other moneys, securities and funds pledged under the related Electric Revenue Bond Resolution.

Application of Revenues in an Event of Default (Section 804)

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, upon demand of the Trustee, Energy Northwest shall pay over to the Trustee (i) forthwith, all moneys, securities and funds, if any, then held by Energy Northwest and pledged under the related Electric Revenue Bond Resolution, and (ii) subject to the provisions of the respective Prior Lien Resolutions as promptly as practicable after receipt thereof, all revenues of the related Project (provided that if other Parity Debt is outstanding Energy Northwest shall pay over to the Trustee the Trustee's pro rata share of such revenues).

Subject to the provisions of the Prior Lien Resolutions, respectively, during the continuance of an Event of Default, the revenues and other moneys of the related Project received by the Trustee shall be applied by the Trustee: first, to the payment of the reasonable and necessary cost of operation, maintenance, repair and replacement of the related Project, including the costs of decommissioning and site restoration, if any, and all other proper disbursements or liabilities made or incurred by the Trustee (including the fees and expenses of counsel to the Trustee); and second, to the then due and overdue payments into the related Debt Service Fund and the due and overdue payments on any related Parity Reimbursement Obligations and the due and overdue payments of any other obligation of Energy Northwest for which the Revenues are pledged on a parity with the pledge under Section 202(a) of the related Electric Revenue Bond Resolution pursuant to a Supplemental Electric Revenue Bond Resolution ("Other Parity Obligations"); and lastly, for any lawful purpose in connection with the related Project.

In the event that at any time the funds held by the Trustee shall be insufficient for the payment of the principal of, premium, if any, and interest then due on the related Electric Revenue Bonds and payments then due on any related Parity Reimbursement Obligations and Other Parity Obligations, such funds (other than funds held for the payment or redemption of particular Electric Revenue Bonds or Parity Reimbursement Obligations or Other Parity Obligations, including, without limiting the generality of the foregoing, amounts held in any Reserve Account for a particular Series of Electric Revenue Bonds) and all revenues of Energy Northwest and other moneys received or collected for the benefit or for the account of owners of the Electric Revenue Bonds and any Parity Reimbursement Obligations and Other Parity Obligations by the Trustee shall be applied as follows:

(1) Unless the principal of all of the related Electric Revenue Bonds shall have become due and payable,

First, to the payment of all necessary and proper operating expenses of the applicable Project and all other proper disbursements or liabilities made or incurred by the Trustee;

Second, to the payment to the persons entitled thereto of all installments of interest then due on the related Electric Revenue Bonds (including any interest on overdue principal) in the order of the maturity of such installments, earliest maturities first, and on any related Parity Reimbursement Obligations and Other Parity Obligations and if the amounts available shall not be sufficient to pay in full any installment or installments of interest maturing on the same date, then to the payment thereof ratably, according to the amounts due thereon, to the persons entitled thereto, without any discrimination or preference; and

Third, to the payment to the persons entitled thereto of the principal and premium, if any, due and unpaid upon the related Electric Revenue Bonds and on any related Parity Reimbursement Obligations and Other Parity Obligations at the time of such payment without preference or priority of any related Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation over any other Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation, and if the amounts available therefor shall not be sufficient to pay in full any principal and premium, if any, due and unpaid upon the related Electric Revenue Bonds and on any related Parity Reimbursement Obligations and Other Parity Obligations at such time, then to the payment thereof, ratably, according to the amounts due respectively for principal and redemption premium, without any discrimination or preference.

(2) If the principal of all of the related Electric Revenue Bonds shall have become due and payable,

First, to the payment of all necessary and proper operating expenses of the related Project and all other proper disbursements or liabilities made or incurred by the Trustee; and

Second, to the payment of the principal and interest then due and unpaid upon the related Electric Revenue Bonds and any related Parity Reimbursement Obligations and Other Parity Obligations without preference or priority of principal over interest or of interest over principal, or of any installment of interest over any other installment of interest, or of any related Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation over any other Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation, ratably, according to the amounts due respectively for principal and interest, to the persons entitled thereto without any discrimination or preference.

Whenever moneys are to be applied as described in the preceding paragraphs, such moneys shall be applied by the Trustee, at such times, and from time to time, as it in its sole discretion shall determine, having due regard to the amount of such moneys available for application and the likelihood of additional moneys becoming available for such application in the future.

If and whenever all overdue installments of interest on all Electric Revenue Bonds and any related Parity Reimbursement Obligations and Other Parity Obligations, together with the reasonable and proper charges, expenses, and liabilities of the owners of the Electric Revenue Bonds or the obligees of such Parity Reimbursement Obligation or Other Parity Obligation, as applicable, their respective agents and attorneys, and all other sums payable by Energy Northwest under the related Electric Revenue Bond Resolution including the Principal Installment or redemption price of all Electric Revenue Bonds which shall then be payable, shall either be paid in full by or for the account of Energy Northwest or provision satisfactory to the Trustee shall be made for such payment, and all defaults under the applicable Electric Revenue Bond Resolutions or the related Electric Revenue Bonds shall be made good and secured to the satisfaction of the Trustee or provision deemed by the Trustee to be adequate therefor, the Trustee shall pay over to Energy Northwest all of its money, securities, funds and revenues then remaining unexpended in the hands of the Trustee (except moneys, securities, funds or revenues deposited or pledged, or required by the terms of the applicable Electric Revenue Bond Resolution to be deposited or pledged, with the Trustee), control of the business and possession of the property of the applicable Project shall be restored to Energy Northwest, and thereupon Energy Northwest and the Trustee shall be restored to their former positions and rights under the applicable Electric Revenue Bond Resolution, and all revenues shall thereafter be applied as provided in Article V of the applicable Electric Revenue Bond Resolution. No such payment to Energy Northwest by the Trustee or resumption of this application of revenues as provided in Article VI of the applicable Electric Revenue Bond Resolution shall extend to or affect any subsequent default under the applicable Electric Revenue Bond Resolution or impair any right consequent thereon.

Remedies Not Exclusive (Section 809)

No remedy by the terms of either of the Electric Revenue Bond Resolutions conferred upon or reserved to the owners of the related Electric Revenue Bonds is intended to be exclusive of any other remedy, but each and every such remedy shall be cumulative and shall be in addition to any other remedy given to the owners of the related Electric Revenue Bonds or now or hereafter existing at law or in equity or by statute.

Waivers of Default (Section 810)

No delay or omission of any owner of Electric Revenue Bonds to exercise any right or power arising upon the occurrence of a default hereunder, including an Event of Default, will impair any right or power or shall be construed to be a waiver of any such default or to be an acquiescence therein. Every power and remedy given by this Article to the Trustee or to the owners of Electric Revenue Bonds may be exercised from time to time and as often as may be deemed expedient by such Trustee or by such owners.

Prior to the declaration of acceleration of the Electric Revenue Bonds as provided in Section 801, the holders of a majority in principal amount of the Electric Revenue Bonds at the time Outstanding, or their attorneys-in-fact duly authorized, may on behalf of the holders of all the Electric Revenue Bonds waive any past default under this Resolution and its consequences, except a default described in paragraph (1), (2), (3), or (4) of Section 801. No such waiver will extend to any subsequent or other default or impair any right consequent thereon.

Supplemental Electric Revenue Bond Resolutions (Article IX)

Supplemental Electric Revenue Bond Resolutions Effective Without Consent of Owners of Electric Revenue Bonds. Energy Northwest, from time to time and at any time and without the consent or concurrence of any owner of any Electric Revenue Bond, may adopt a resolution amendatory of each Electric Revenue Bond Resolution or supplemental to each Electric Revenue Bond Resolution (i) for the purpose of providing for the issuance of Electric Revenue Bonds pursuant to the provisions of Article II of each Electric Revenue Bond Resolution, or (ii) if the provisions of such Supplemental Electric Revenue Bond Resolutions shall not adversely affect the rights of the owners of the Electric Revenue Bonds of each Series or, if a Series consists of two or more subseries, of each subseries thereof, affected by such Supplemental Electric Revenue Bond Resolutions then outstanding, for any one or more of the following purposes:

(1) to make any changes or corrections in the Electric Revenue Bond Resolutions as to which Energy Northwest shall have been advised by counsel that the same are required for the purpose of curing or correcting any ambiguity or defective or inconsistent provision or omission or mistake or manifest error contained in the Electric Revenue Bond Resolutions, or to insert in the Electric Revenue Bond Resolutions such provisions clarifying matters or questions arising under the Electric Revenue Bond Resolutions as are necessary or desirable;

(2) to add additional covenants and agreements of Energy Northwest for the purpose of further securing the payment of the Electric Revenue Bonds;

(3) to surrender any right, power or privilege reserved to or conferred upon Energy Northwest by the terms of the Electric Revenue Bond Resolutions;

(4) to confirm as further assurance any lien, pledge or charge, or the subjection to any lien, pledge, or charge, created or to be created by the provisions of the Electric Revenue Bond Resolutions;

(5) to grant or to confer upon the owners of the Electric Revenue Bonds any additional rights, remedies, powers, authority or security that lawfully may be granted to or conferred upon them, or to grant to or to

confer upon the Trustee for the benefit of the owners of the Electric Revenue Bonds any additional rights, duties, remedies, powers, authority or security or to provide for one or more Credit Facilities;

(6) to make any appointment or to add any provision, in either case, required or permitted by the Electric Revenue Bond Resolutions to be so made or added pursuant to a Supplemental Electric Revenue Bond Resolution;

(7) to enter into Payment Agreements; and

(8) to make any other change which Energy Northwest deems necessary or desirable and which does not adversely affect the rights of the Bondholders.

Supplemental Electric Revenue Bond Resolutions Effective With Consent of Bondholders. At any time, Supplemental Electric Revenue Bond Resolutions may be adopted subject to consent by Bondholders in accordance with and subject to the provisions of each Electric Revenue Bond Resolution, which Supplemental Electric Revenue Bond Resolutions, upon the filing with the Trustee of a copy thereof certified by an authorized officer of Energy Northwest and upon compliance with the provisions of Article X of each Electric Revenue Bond Resolution, shall become fully effective in accordance with its terms as provided in said Article.

Powers of Amendment (Section 1002)

Any modification or amendment of the Electric Revenue Bond Resolutions or of the rights and obligations of Energy Northwest and of the owner of the Electric Revenue Bonds thereunder, in any particular, may be made by Supplemental Electric Revenue Bond Resolutions, with the written consent given as provided in each Electric Revenue Bond Resolution, (i) of the owners of not less than a majority in principal amount of the related Electric Revenue Bonds outstanding at the time such consent is given, and (ii) in case less than all of the several Series of Electric Revenue Bonds or, if any Series consists of two or more subseries, the subseries thereof, then outstanding are affected by the modification or amendment, of the owners of not less than a majority in principal amount of the Electric Revenue Bonds of such Series or subseries, as the case may be, so affected and outstanding at the time such consent is given; except that if such modification or amendment will, by its terms, not take effect so long as any Electric Revenue Bonds of any specified like Series, subseries, if applicable, and maturity remain outstanding, the consent of the owners of such Electric Revenue Bonds shall not be required and such Electric Revenue Bonds shall not be deemed to be outstanding for the purpose of any calculation of outstanding Electric Revenue Bonds under this provision of each Electric Revenue Bond Resolution. No such modification or amendment shall permit a change in the terms of redemption or maturity of the principal of any outstanding Electric Revenue Bond or of any installment of interest thereon or a reduction in the principal amount or the redemption price thereof or in the rate of interest thereon without the consent of the owner of such Electric Revenue Bond, or shall reduce the percentages or otherwise affect the classes of Electric Revenue Bonds the consent of the owners of which is required to effect any such modification or amendment, or permit a preference or priority of any Electric Revenue Bond over any other or shall change or modify any of the rights or obligations of any fiduciary without its written assent thereto. For the purposes of this provision of each Electric Revenue Bond Resolution, a Series or subseries, as the case may be, shall be deemed to be affected by a modification or amendment of each Electric Revenue Bond Resolution if the same adversely affects or diminishes the rights of the owners of Electric Revenue Bonds of such Series or subseries, respectively. The Trustee may in its discretion determine whether or not in accordance with the foregoing powers of amendment of the Electric Revenue Bonds of any particular Series, Subseries, if applicable, or maturity would be affected by any modification or amendment of the Electric Revenue Bond Resolutions and any such determination shall be binding and conclusive on Energy Northwest and all owners of Electric Revenue Bonds. For the purposes of this Section, the owners of the Electric Revenue Bonds may include the initial owners thereof, regardless of whether such Electric Revenue Bonds are being held for immediate resale.

Defeasance (Article XI)

Except as otherwise provided in each Supplemental Electric Revenue Bond Resolution authorizing the issuance of variable rate Electric Revenue Bonds, the obligations of Energy Northwest under the Electric Revenue Bond Resolutions and the liens, pledges, charges, trusts, covenants and agreements of Energy Northwest made or provided for in such Electric Revenue Bond Resolutions, shall be fully discharged and satisfied as to any related Electric Revenue Bond and such related Electric Revenue Bond shall no longer be deemed to be outstanding hereunder,

(i) when such related Electric Revenue Bond shall have been canceled, or shall have been surrendered for cancellation or is subject to cancellation, or shall have been purchased by the Trustee from moneys held under the related Electric Revenue Bond Resolutions; or

(ii) as to any related Electric Revenue Bond not canceled or surrendered for cancellation or subject to cancellation or so purchased, when payment of the principal of and premium, if any, on such related Electric Revenue Bond, plus interest on such principal to the due date thereof (whether such due date be by reason of maturity or upon redemption or prepayment, or otherwise) either (A) shall have been made or caused to be made in accordance with the terms thereof, or (B) shall have been provided for by irrevocably depositing with the trustee or a paying agent for such Electric Revenue Bond, in trust, and irrevocably appropriating and setting aside exclusively for such payment, either (1) moneys sufficient to make such payment, or (2) Defeasance Obligations maturing, or redeemable at the option of the owner thereof, as to principal and interest in such amount and at such times as will insure the availability of sufficient moneys to make such payment, or a combination thereof, whichever Energy Northwest deems to be in its best interest, and all necessary and proper fees, compensation and expenses of the Trustee and the paying agents pertaining to the Electric Revenue Bond with respect to which such deposit is made shall have been paid or the payment thereof provided for to the satisfaction of the Trustee and said paying agents. In addition, with respect to the Series 2010-C (Taxable) Build America Bonds, 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 IRS 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:

(1) the amount included in the annual budget for fuel adopted pursuant to the Project 1 Project Agreement,

(2) all amounts received by Energy Northwest as fuel credits, including the proceeds of the sale of fuel creditable to operations, and

(3) 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 4to 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 (except for the final paragraph) has been provided by the Depository Trust Company, New York, New York ("DTC"). Energy Northwest makes no representation regarding the accuracy or completeness thereof. Beneficial Owners (as hereinafter defined) should therefore confirm the following with DTC or the DTC Participants (as hereinafter defined).

DTC will act as securities depository for the 2010 Bonds. The 2010 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 2010 Bond certificate will be issued for each maturity of the 2010 Bonds in the principal amount of such maturity and will be deposited with DTC.

DTC is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments from over 100 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, and trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). The DTC Rules applicable to its DTC Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com and www.dtc.org.

Purchases of the 2010 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 2010 Bonds on DTC's records. The ownership interest of each actual purchaser of each 2010 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 2010 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 2010 Bonds, except in the event that use of the book entry-entry system for the 2010 Bonds is discontinued.

To facilitate subsequent transfers, all 2010 Bonds deposited by DTC Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of 2010 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 2010 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such 2010 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 2010 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. DTC will be requested to redeem the 2010-C Bonds pro rata.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the 2010 Bonds unless authorized by a Direct Participant in accordance with DTC's MMI 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 2010 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds, distributions, and dividend payments on the 2010 Bonds will be made to Cede & Co. or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from Energy Northwest or the Bond Registrar, on payable date in accordance with their respective holdings shown on DTC's records. Payments by DTC Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such DTC Participant and not of DTC, the Bond Registrar, or Energy Northwest, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds, distributions, and dividend payments to Cede & Co. (or any other nominee as may be requested by an authorized representative of DTC) is the responsibility of Energy Northwest or the Bond Registrar, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the 2010 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, 2010 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, 2010 Bond certificates will be printed and delivered to DTC.

With respect to 2010 Bonds registered on the Bond Register in the name of Cede & Co., as nominee of DTC, Energy Northwest and the Bond Registrar shall have no responsibility or obligation to any DTC Participant or to any person on behalf of whom a DTC Participant holds an interest in the 2010 Bonds with respect to, (i) the accuracy of the records of DTC, Cede & Co. or any DTC Participant with respect to any ownership interest in the 2010 Bonds; (ii) the delivery to any DTC Participant or any other person, other than a bondowner as shown on the Bond Register, of any notice with respect to the 2010 Bonds, including any notice of redemption; (iii) the payment to any DTC Participant or any other person, other than a bondowner as shown on the Bond Register, of any amount with respect to principal of, premium, if any, or interest on the 2010 Bonds; (iv) the selection by DTC or any DTC Participant of any person to receive payment in the event of a partial redemption of the 2010 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 2010 Bond is registered on the Bond Register, as the holder and absolute owner of such 2010 Bond for the purpose of payment of principal and interest with respect to such 2010 Bond, for the purpose of giving notices of redemption and other matters with respect to such 2010 Bond, for the purpose of registering transfers with respect to such 2010 Bond, and for all other purposes whatsoever. For the purposes of this Official Statement, the term "Beneficial Owner" shall include the person for whom the DTC Participant acquires an interest in the 2010 Bonds.

SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENTS

To assist the Underwriters in complying with Rule 15c2-12, Energy Northwest and Bonneville will enter into written agreements (the "Disclosure Agreements") for the benefit of the holders and beneficial owners of the 2010 Bonds to provide continuing disclosure.

Definitions.

In addition to the definitions set forth in the Net Billed Resolutions and the Disclosure Agreements, which apply to any capitalized term used in the Disclosure Agreements, 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 2010 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" and "Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments."

"Energy Northwest Annual Information" means financial information and operating data generally of the type included in the final Official Statement for the 2010 Bonds in the table labeled "Energy Northwest Revenue Bonds Outstanding as of December 31, 2009" 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 the MSRB.

"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 the MSRB.

"MSRB" means the Municipal Securities Rulemaking Board or any successors to its functions.

"Rule 15c2-12" means Rule 15c2-12 under the Securities Exchange Act of 1934, as amended through the date of this Disclosure Agreement, including any official interpretations thereof promulgated on or prior to the effective date of this Disclosure Agreement.

Financial Information.

Bonneville. Bonneville agrees to provide to the MSRB as designated by the SEC in accordance with the Rule, no later than March 31 of each year, commencing with the FCRPS Fiscal Year ending September 30, 2010:

(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 the MSRB as designated by the SEC in accordance with the Rule, no later than December 31 of each year, commencing with Energy Northwest Fiscal Year ending June 30, 2010:

(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 above, Bonneville and Energy Northwest may specifically cross-reference other documents available to the public on the internet website of the MSRB, or filed with the SEC.

Notice of Failure to Provide Financial Information. Energy Northwest agrees to provide or cause to be provided, in a timely manner, to the MSRB (i) notice of Bonneville's failure to provide the annual financial information described above on or prior to the applicable date set forth above and (ii) notice of Energy Northwest's failure to provide the annual financial information described above on or prior to the applicable date set forth above.

Material Events Notices.

Energy Northwest agrees to provide or cause to be provided, in a timely manner, to the MSRB, notice of the occurrence of any of the following events with respect to the 2010 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 2010-A Bonds and 2010-B Bonds;

(vii) Modifications to rights of 2010 Bondholders;

(viii) Optional, contingent or unscheduled calls of any 2010 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 2010 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 2010 Bonds.

Availability of Information from the MSRB.

Bonneville and Energy Northwest have agreed to provide the foregoing information only to the MSRB. The information filed with the MSRB is available to the public without charge through an internet portal.

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 2010 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 2010 Bonds; and (ii) notifies the MSRB 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 2010 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 2010 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 2010 Bonds shall have any rights available to them under law with respect to remedies hereunder against Bonneville.

[This Page Intentionally Left Blank]

[THIS PAGE INTENTIONALLY LEFT BLANK]

[THIS PAGE INTENTIONALLY LEFT BLANK]

ENERGY NORTHWEST • PROJECT 1, PROJECT 3 & COLUMBIA GENERATING STATION ELECTRIC REVENUE & REFUNDING BONDS, SERIES 2010 - FEBRUARY 25, 2010

Printed by: ImageMaster, Inc.