Columbia River System Operation Review

Final Environmental Impact Statement

Appendix P

Canadian Entitlement Allocation Agreements (CEAA)

BONNEVILLE POWER ADMINISTRATION

US Army Corps of Engineers
North Pacific Division

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF RECLAMATION

DOE/EIS-0170

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PUBLIC INVOLVEMENT IN THE SOR PROCESS

The Bureau of Reclamation, Corps of Engineers, and Bonneville Power Administration wish to thank those who reviewed the Columbia River System Operation Review (SOR) Draft EIS and appendices for their comments. Your comments have provided valuable public, agency, and tribal input to the SOR NEPA process. Throughout the SOR, we have made a continuing effort to keep the public informed and involved.

Fourteen public scoping meetings were held in 1990. A series of public roundtables was conducted in November 1991 to provide an update on the status of SOR studies. The lead agencies went back to most of the 14 communities in 1992 with 10 initial system operating strategies developed from the screening process. From those meetings and other consultations, seven SOS alternatives (with options) were developed and subjected to full–scale analysis. The analysis results were presented in the Draft EIS released in July 1994. The lead agencies also developed alternatives for the other proposed SOR actions, including a Columbia River Regional Forum for assisting in the determination of future SOSs, Pacific Northwest Coordination Agreement alternatives for power coordination, and Canadian Entitlement Allocation Agreements alternatives. A series of nine public meetings was held in September and October 1994 to present the Draft EIS and appendices and solicit public input on the SOR. The lead agencies received 282 formal written comments. Your comments have been used to revise and shape the alternatives presented in the Final EIS.

Regular newsletters on the progress of the SOR have been issued. Since 1990, 20 issues of *Streamline* have been sent to individuals, agencies, organizations, and tribes in the region on a mailing list of over 5,000. Several special publications explaining various aspects of the study have also been prepared and mailed to those on the mailing list. Those include:

- The Columbia River: A System Under Stress
- The Columbia River System: The Inside Story
- Screening Analysis: A Summary
- Screening Analysis: Volumes 1 and 2
- Power System Coordination: A Guide to the Pacific Northwest Coordination Agreement
- Modeling the System: How Computers are Used in Columbia River Planning
- Daily/Hourly Hydrosystem Operation: How the Columbia River System Responds to Short–Term Needs

Copies of these documents, the Final EIS, and other appendices can be obtained from any of the lead agencies, or from libraries in your area.

Your questions and comments on these documents should be addressed to:

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PREFACE: SETTING THE STAGE FOR THE SYSTEM OPERATION REVIEW

WHAT IS THE SOR AND WHY IS IT BEING CONDUCTED?

The Columbia River System is a vast and complex combination of Federal and non–Federal facilities used for many purposes including power production, irrigation, navigation, flood control, recreation, fish and wildlife habitat and municipal and industrial water supply. Each river use competes for the limited water resources in the Columbia River Basin.

To date, responsibility for managing these river uses has been shared by a number of Federal, state, and local agencies. Operation of the Federal Columbia River system is the responsibility of the Bureau of Reclamation (Reclamation), Corps of Engineers (Corps) and Bonneville Power Administration (BPA).

The System Operation Review (SOR) is a study and environmental compliance process being used by the three Federal agencies to analyze future operations of the system and river use issues. The goal of the SOR is to achieve a coordinated system operation strategy for the river that better meets the needs of all river users. The SOR began in early 1990, prior to the filing of petitions for endangered status for several salmon species under the Endangered Species Act.

The comprehensive review of Columbia River operations encompassed by the SOR was prompted by the need for Federal decisions to (1) develop a coordinated system operating strategy (SOS) for managing the multiple uses of the system into the 21st century; (2) provide interested parties with a continuing and increased long–term role in system planning (Columbia River Regional Forum); (3) renegotiate and renew the Pacific Northwest Coordination Agreement (PNCA), a contractual arrangement among the region's major hydroelectric–generating utilities and affected Federal agencies to provide for coordinated power generation on the Columbia River system; and (4) renew or develop new Canadian Entitlement Allocation Agreements (contracts that divide Canada's share of Columbia River Treaty downstream power benefits and obligations among three participating public utility districts and BPA). The review provides the environmental analysis required by the National Environmental Policy Act (NEPA).

This technical appendix addresses only the effects of alternative system operating strategies for managing the Columbia River system. The environmental impact statement (EIS) itself and some of the other appendices present analyses of the alternative approaches to the other three decisions considered as part of the SOR.

WHO IS CONDUCTING THE SOR?

The SOR is a joint project of Reclamation, the Corps, and BPA—the three agencies that share responsibility and legal authority for managing the Federal Columbia River System. The National Marine Fisheries Service (NMFS), U.S. Fish and Wildlife Service (USFWS), and National Park Service (NPS), as agencies with both jurisdiction and expertise with regard to some aspects of the SOR, are cooperating agencies. They contribute information, analysis, and recommendations where appropriate. The U.S. Forest Service (USFS) was also a cooperating agency, but asked to be removed from that role in 1994 after assessing its role and the press of other activities.

HOW IS THE SOR BEING CONDUCTED?

The system operating strategies analyzed in the SOR could have significant environmental impacts. The study team developed a three–stage process—scoping, screening, and full–scale analysis of the strategies—to address the many issues relevant to the SOR.

At the core of the analysis are 10 work groups. The work groups include members of the lead and cooperating agencies, state and local government agencies, representatives of Indian tribes, and members of the public. Each of these work groups has a single river use (resource) to consider.

Early in the process during the screening phase, the 10 work groups were asked to develop an alternative for project and system operations that would provide the greatest benefit to their river use, and one or more alternatives that, while not ideal, would provide an acceptable environment for their river use. Some groups responded with alternatives that were evaluated in this early phase and, to some extent, influenced the alternatives evaluated in the Draft and Final EIS. Additional alternatives came from scoping for the SOR and from other institutional sources within the region. The screening analysis studied 90 system operation alternatives.

Other work groups were subsequently formed to provide projectwide analysis, such as economics, river operation simulation, and public involvement.

The three-phase analysis process is described briefly below.

- **Scoping/Pilot Study**—After holding public meetings in 14 cities around the region, and coordinating with local, state, and Federal agencies and Indian tribes, the lead agencies established the geographic and jurisdictional scope of the study and defined the issues that would drive the EIS. The geographic area for the study is the Columbia River Basin (Figure P-1). The jurisdictional scope of the SOR encompasses the 14 Federal projects on the Columbia and lower Snake Rivers that are operated by the Corps and Reclamation and coordinated for hydropower under the PNCA. BPA markets the power produced at these facilities. A pilot study examining three alternatives in four river resource areas was completed to test the decision analysis method proposed for use in the SOR.
- **Screening**—Work groups, involving regional experts and Federal agency staff, were created for 10 resource areas and several support functions. The work groups developed computer screening models and applied them to the 90 alternatives identified during screening. They compared the impacts to a baseline operating year—1992—and ranked each alternative according to its impact on their resource or river use. The lead agencies reviewed the results with the public in a series of regional meetings in September 1992.
- **Full-Scale Analysis**—Based on public comment received on the screening results, the study team sorted, categorized, and blended the alternatives into seven basic types of operating strategies. These alternative strategies, which have multiple options, were then subjected to detailed impact analysis. Twenty-one possible options were evaluated. Results and tradeoffs for each resource or river use were discussed in separate technical appendices and summarized in the Draft EIS. Public review and comment on the Draft EIS was conducted during the summer and fall of 1994. The lead agencies adjusted the alternatives based on the comments, eliminating a few options and substituting new options, and reevaluated them during the past 8 months. Results are summarized in the Final EIS.

Alternatives for the Pacific Northwest Coordination Agreement (PNCA), the Columbia River Regional Forum (Forum), and the Canadian Entitlement Allocation Agreements (CEAA) did not use the three-stage process described above. The environmental impacts from the PNCA and CEAA were not significant and there were no anticipated impacts from the Regional Forum. The procedures used to analyze alternatives for these actions are described in their respective technical appendices.

For detailed information on alternatives presented in the Draft EIS, refer to that document and its appendices.

WHAT SOS ALTERNATIVES ARE CONSIDERED IN THE FINAL EIS?

Seven alternative System Operating Strategies (SOS) were considered in the Draft EIS. Each of the seven SOSs contained several options bringing the total number of alternatives considered to 21. Based on review of the Draft EIS and corresponding adjustments, the agencies have identified 7 operating strategies that are evaluated in this Final EIS. Accounting for options, a total of 13 alternatives is now under consideration. Six of the alternatives remain unchanged from the specific options considered in the Draft EIS. One is a revision to a previously considered alternative, and the rest represent replacement or new alternatives. The basic categories of SOSs and the numbering convention remains the same as was used in the Draft EIS. However, because some of the alternatives have been dropped, the numbering of the final SOSs are not consecutive. There is one new SOS category, Settlement Discussion Alternatives, which is labeled SOS 9 and replaces the SOS 7 category. This category of alternatives arose as a consequence of litigation on the 1993 Biological Opinion and ESA Consultation for 1995.

The 13 system operating strategies for the Federal Columbia River system that are analyzed for the Final EIS are:

SOS 1a Pre Salmon Summit Operation represents operations as they existed from around 1983 through the 1990–91 operating year, prior to the ESA listing of three species of salmon as endangered or threatened.

SOS 1b Optimum Load–Following Operation represents operations as they existed prior to changes resulting from the Regional Act. It attempts to optimize the load–following capability of the system within certain constraints of reservoir operation.

SOS 2c Current Operation/No–Action Alternative represents an operation consistent with that specified in the Corps of Engineers' 1993 Supplemental EIS. It is similar to system operation that occurred in 1992 after three species of salmon were listed under ESA.

SOS 2d [New] 1994–98 Biological Opinion represents the 1994–98 Biological Opinion operation that includes up to 4 MAF flow augmentation on the Columbia, flow targets at McNary and Lower Granite, specific volume releases from Dworshak, Brownlee, and the Upper Snake, meeting sturgeon flows 3 out of 10 years, and operating lower Snake projects at MOP and John Day at MIP.

SOS 4c [Rev.] Stable Storage Operation with Modified Grand Coulee Flood Control attempts to achieve specific monthly elevation targets year round that improve the environmental conditions at storage projects for recreation, resident fish, and wildlife. Integrated Rules Curves (IRCs) at Libby and Hungry Horse are applied.

SOS 5b Natural River Operation draws down the four lower Snake River projects to near river bed levels for four and one–half months during the spring and summer salmon migration period, by assuming new low level outlets are constructed at each project.

SOS 5c [New] Permanent Natural River Operation operates the four lower Snake River projects to near river bed levels year round.

SOS 6b Fixed Drawdown Operation draws down the four lower Snake River projects to near spillway crest levels for four and one–half months during the spring and summer salmon migration period.

SOS 6d Lower Granite Drawdown Operation draws down Lower Granite project only to near spillway crest level for four and one–half months.

SOS 9a [New] Detailed Fishery Operating Plan includes flow targets at The Dalles based on the previous year's end–of–year storage content, specific volumes of releases for the Snake River, the drawdown of Lower Snake River projects to near spillway crest level for four and one–half months, specified spill percentages, and no fish transportation.

SOS 9b [New] Adaptive Management establishes flow targets at McNary and Lower Granite based on runoff forecasts, with specific volumes of releases to meet Lower Granite flow targets and specific spill percentages at run–of–river projects.

SOS 9c [New] Balanced Impacts Operation draws down the four lower Snake River projects near spillway crest levels for two and one–half months during the spring salmon migration period. Refill begins after July 15. This alternative also provides 1994–98 Biological Opinion flow augmentation, integrated rule curve operation at Libby and Hungry Horse, a reduced flow target at Lower Granite due to drawdown, winter drawup at Albeni Falls, and spill to achieve no higher than 120 percent daily average for total dissolved gas.

SOS PA Preferred Alternative represents the operation proposed by NMFS and USFWS in their Biological Opinions for 1995 and future years; this SOS operates the storage projects to meet flood control rule curves in the fall and winter in order to meet spring and summer flow targets for Lower Granite and McNary, and includes summer draft limits for the storage projects.

WHAT CEAA ALTERNATIVES ARE CONSIDERED IN THIS TECHNICAL APPENDIX?

Four alternatives for the Canadian Entitlement Allocation Agreements were evaluated in this appendix to the Final EIS. Briefly, they are:

- **CEAA 1** – The no–action alternative. The Federal obligation for the Canadian Entitlement return is 100 percent while the non–Federal obligation is 0 percent.
- **CEAA 2** – This alternative is a bound that maximizes the non–Federal obligation while minimizing the Federal obligation. The Federal obligation for the Canadian Entitlement return is 55 percent while the non–Federal obligation is 45 percent.
- **CEAA 3** – This alternative provides a point between Alternatives 1 and 2. The Federal obligation for the Canadian Entitlement return is 70 percent while the non–Federal obligation is 30 percent.
- **CEAA 4** – This alternative was developed to consider impacts if Federal and non–Federal parties are unable to negotiate new allocation agreements.

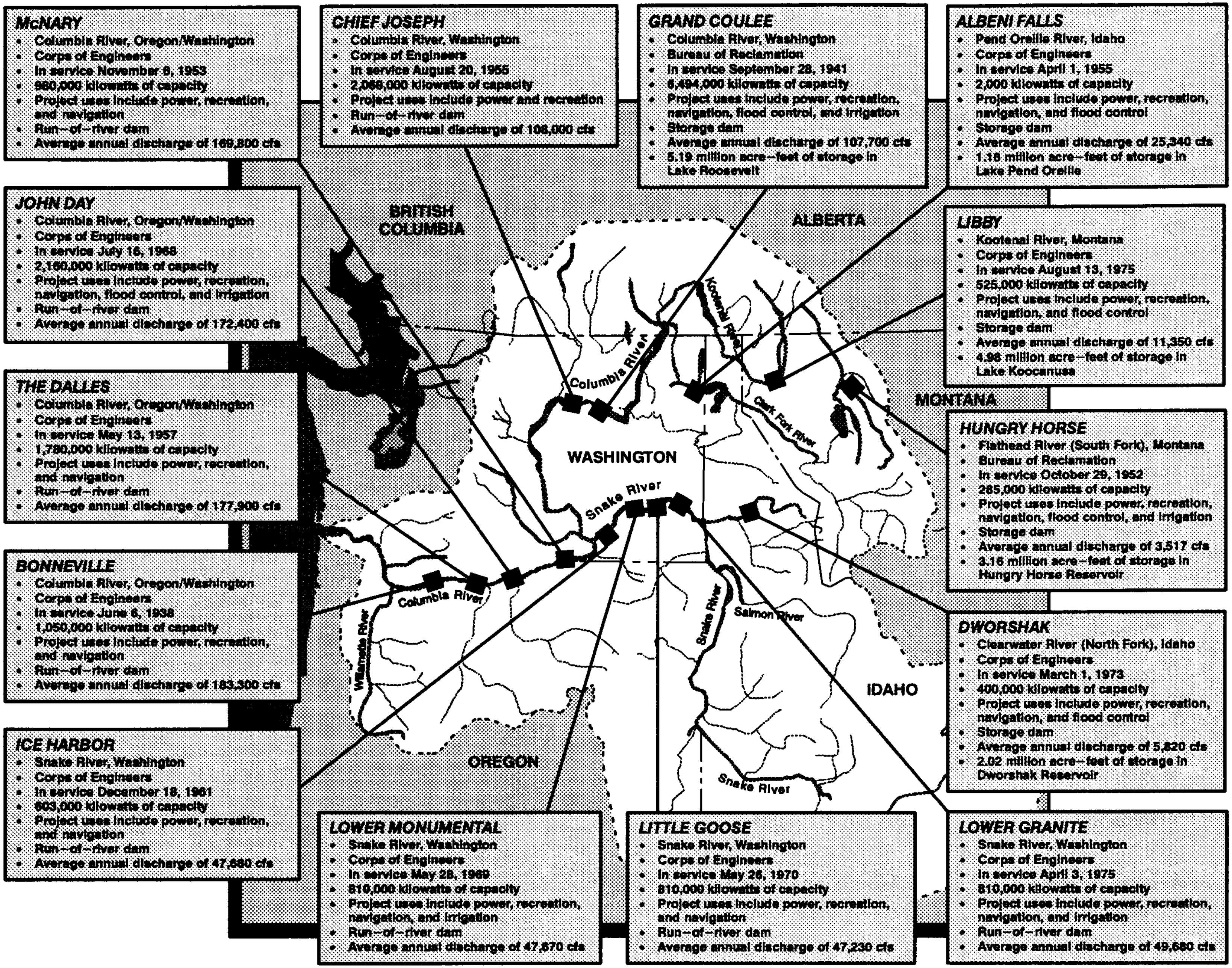
WHAT DO THE TECHNICAL APPENDICES COVER?

This technical appendix is 1 of 20 prepared for the SOR. They are:

A. River Operation Simulation
B. Air Quality
C. Anadromous Fish & Juvenile Fish Transportation
D. Cultural Resources
E. Flood Control
F. Irrigation/Municipal and Industrial Water Supply
G. Land Use and Development
H. Navigation
I. Power
J. Recreation
K. Resident Fish
L. Soils, Geology, and Groundwater
M. Water Quality
N. Wildlife
O. Economic and Social Impacts
P. Canadian Entitlement Allocation Agreements
Q. Columbia River Regional Forum
R. Pacific Northwest Coordination Agreement
S. U. S. Fish and Wildlife Service Coordination Act Report
T. Comments and Responses

Each appendix presents a detailed description of the work group's analysis of alternatives, from the scoping process through full–scale analysis. Several appendices address specific SOR functions (e.g., River Operation Simulation), rather than individual resources, or the institutional alternatives (e.g., PNCA) being considered within the SOR. The technical appendices provide the basis for developing and analyzing alternative system operating strategies in the EIS. The EIS presents an integrated review of the vast wealth of information contained in the appendices, with a focus on key issues and impacts. In addition, the three agencies have prepared a brief summary of the EIS to highlight issues critical to decision makers and the public.

There are many interrelationships among the different resources and river uses, and some of the appendices provide supporting data for analyses presented in other appendices. This Canadian Entitlement Allocation Agreement appendix relies on supporting data contained in Appendix A. For complete coverage of all aspects of Canadian Entitlement Allocation Agreement and relationships to anadromous fish, cultural resources, recreation, and resident fish, readers may wish to review Appendices C, D, J, and K, in concert.



1 million acre feet = 1.234 billion cubic meters
1 cubic foot per second = 0.028 cubic meters per second

Figure P–1. Projects in the System Operation Review.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 1

INTRODUCTION AND SCOPE

1.1 INTRODUCTION

The U.S. Entity, comprised of the Bonneville Power Administrator and the Division Engineer, Corps of Engineers North Pacific Division, will negotiate and proposes to enter into agreements – The Canadian Entitlement Allocation Agreements – with the owners of the five non–Federal mid–Columbia hydroelectric projects. The owners of the five non–Federal Columbia River hydroelectric projects are Chelan, Douglas, and Grant County Public Utility Districts (PUD). Utilities that may participate in the negotiations and who currently purchase power from the five non–Federal projects include; Portland General Electric, PacifiCorp, Puget Sound Power and Light, Washington Water Power, Tacoma City Light, Seattle City Light, Cowlitz County PUD, Eugene Water and Electric Board, City of McMinnville, City of Milton–Freewater, Kittitas County PUD, Colockum Transmission Company, and the City of Forest Grove.

The Columbia River Treaty (Treaty) was executed in 1964 as an important component of regional plans to increase the Northwest's hydroelectric resource capability. The Treaty requires the U.S. to deliver to Canada half of the downstream power benefits generated in the U.S. resulting from the construction and operation of three storage reservoirs in Canada. Canada's half of the downstream power benefits is referred to as the Canadian Entitlement. Concurrent with the Treaty, the Canadian Entitlement Allocation Agreements (CEAA) and the Pacific Northwest Coordination Agreement (PNCA) were also executed in 1964.

The purpose of the original CEAA was to establish how the Canadian Entitlement was to be attributed collectively to the six Federal projects and to each of the five non–Federal projects located downstream from the three Canadian storage projects. The CEAA now in effect between the PUDs and the U.S. Entity define and allocate the Canadian Entitlement. The Canadian Entitlement is computed on the basis that the PNW hydroelectric system is operated in coordinated manner. Non–Federal utilities committed to provide a portion of the Canadian Entitlement in return for an agreement by the U.S. Government to plan and operate in a coordinated manner in order to realize the benefits envisioned by the Treaty. Accordingly, the CEAA and the PNCA are linked to the Treaty.

Both the CEAA and the PNCA expire in 2003. The U.S. obligation to return the Canadian Entitlement continues, at a minimum, until 2024, the first year the Treaty can be terminated with 10 years notice. With the expiration of the current CEAA and PNCA, Federal and non–Federal parties will develop new agreements to cover the remaining minimum term of the Treaty. The new CEAA will begin to replace the existing agreements when the first portion of the Canadian Entitlement must be returned to Canada, beginning in 1998.

The purpose of this technical appendix is to provide the environmental review necessary to enter into agreements regarding the distribution between Federal and non–Federal project owners with respect to delivery of the Canadian Entitlement obligation to Canada for the period 1998 through 2024. Environmental review of the new PNCA agreement is discussed in Technical Appendix R, Pacific Northwest Coordination Agreement.

1.2 SCOPE OF THE ENVIRONMENTAL REVIEW

The System Operation Review addresses questions concerning operation of the Federal Columbia River Power System (FCRPS) in the context of a "System Operating Strategy" (SOS). The potential strategies for using the Federal system span a spectrum from maximizing power to maximizing fish flows (See Preface). The CEAA will not influence power system operations under a given SOS for two reasons:

(1) the most likely scenario for satisfying the Canadian Entitlement obligation is the acquisition of new resources or the purchase of power, and

(2) to the extent that the FCRPS and non–Federal projects are used to generate power (or the operation changes because of new resources) for delivery of the Canadian Entitlement to Canada, river flow changes, if any, would be minor.

The CEAA will specify a Federal and Non–Federal obligation to deliver Canadian Entitlement that may be satisfied by hydroelectric power or other resources produced under any of the various SOSs. Since the hydro system operation is virtually independent of the allocation alternatives, the environmental impacts to the FCRPS and non–Federal projects are expected to be minor.

The obligation to deliver the Canadian Entitlement power may ultimately be satisfied in one of a number of ways, and will be negotiated by the U.S. and Canada. The environmental impacts of delivering the power at various possible locations, purchasing all or a portion of the obligation, etc., will be examined in a separate environmental impact statement (EIS), the Delivery of Canadian Entitlement EIS. The environmental impacts of resource acquisition choices that may be made to meet BPA's load obligations (including delivery of the Canadian Entitlement) were examined in the Resource Programs EIS, dated February 1993. The scope of this analysis is limited to the environmental impacts to the FCRPS and non–Federal projects resulting from alternative allocations between Federal and non–Federal parties for delivery of the Canadian Entitlement.

The scope of this appendix encompasses four alternatives. Alternative 1, the no–action alternative, assumes the current Allocation Agreements expire without replacement and that the Federal system would assume the entire obligation to deliver the Canadian Entitlement. Alternative 2 was developed considering factors that would minimize the Federal obligation while maximizing the non–Federal obligation. Alternative 3 provides a point between Alternative 1 and 2. Alternative 4 assumes that the parties are unable to negotiate new Allocation Agreements. By identifying the likely range of allocation outcomes, the number of alternatives is narrowed and the actual outcome will likely fall within the range examined.

CHAPTER 2

BACKGROUND AND AFFECTED ENVIRONMENT

2.1 BACKGROUND

The Columbia River Treaty between the U.S. and Canada was signed in 1961 and ratified by the Governments in 1964. The Treaty required Canada to construct and operate 15.5 MAF of storage on the Columbia River and a tributary in Canada for optimum power generation and flood control downstream in Canada and the U.S.. It also allowed the U.S. to construct the Libby project on the Kootenai River in Montana, which backs up water 42 miles into Canada when full. The Canadian Treaty storage projects are Duncan, Keenleyside (Arrow Lakes), and Mica. Duncan began operation in 1967, followed by Arrow in 1968, and Libby and Mica in 1973. Please see Figure 2–1 for a map of the major Columbia River Basin hydroelectric projects including the Treaty projects.

The Treaty established the U.S. and Canadian Entities as the implementing agencies for each Government. The Canadian Government designated British Columbia Hydro and Power Authority as the Canadian Entity. The U.S. Government designated the Administrator of Bonneville Power Administration and the Division Engineer of the Corps of Engineers, North Pacific Division as the U.S. Entity. The Entities are charged with carrying out most of the functions agreed to under the Treaty. Either Government has the option to terminate the Treaty (except for certain provisions) after September 2024 with 10 years written notice.

Regulation of streamflows by the three Canadian Treaty reservoirs enables dams downstream in the U. S. to generate more usable electricity. This increase in usable electricity 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 downstream power benefits are derived under a formula prescribed by the Treaty and are determined by computing the difference in the hydroelectric power capable of being produced in the U.S. base system with and without the use of Canadian storage. The U.S. base system is defined in Annex B of the Treaty and is essentially the hydroelectric system that existed in the Columbia River Basin in 1961. The Treaty specifies a point on the U.S./Canadian border near Oliver, B.C., for the delivery of the Canadian Entitlement power unless a different point of delivery is mutually agreed upon by the U.S. and Canadian Entities.

The Canadian Entitlement has both an energy and capacity component, defined by the Treaty as average annual usable energy and dependable capacity. The energy component may be characterized as the total number of megawatt–hours delivered over a specified time–usually a year. More typically, it is characterized as the average rate of delivery over such a time period, or "average megawatts" (aMW). The capacity component may be characterized as the maximum rate of delivery allowed in megawatts (MW). Defining a capacity component in excess of the average megawatt energy figure allows the flexibility to shape the returned energy into time periods that more closely reflect the use of the energy, or its marketability.

The Treaty provided that if Canada and the U.S. agreed, Canada could sell its share of the downstream power benefits in the U.S. Canada did not need the additional power at the time the Treaty was signed. Therefore, the Canadian Entitlement was initially sold to the Columbia Storage Power Exchange (CSPE), a nonprofit corporation representing a group of 41 Pacific Northwest (PNW) utilities in the U.S., for a period of thirty years from the completion of each dam. These thirty year periods expire in 1998, 1999, and 2003.

LEGEND

Columbia River Treaty Dams

Other Hydroelectric Projects

Figure 2–1. Major Columbia River Basin Hydroelectric Projects.

The Treaty and the subsequent sale of the Canadian Entitlement resulted in a culmination of other regional events which include:

(1) Canadian Entitlement Allocation Agreements: Concurrent with the purchase of the Canadian Entitlement by CSPE, CEAA were signed that specified the obligation to deliver the Canadian Entitlement to the CSPE purchasers. The obligation to deliver Canadian Entitlement power was allocated among the six Federal projects collectively and to each of the five non–Federal projects downstream of Treaty storage. The five non–Federal projects are Priest Rapids, Wanapum, Rock Island, Rocky Reach, and Wells which are owned by the Public Utility Districts of Grant, Chelan, and Douglas Counties, Washington. The six Federal projects are Bonneville, The Dalles, John Day, McNary, Chief Joseph, and Grand Coulee. Under the authority provided by Article XI of the Treaty, the U.S. Entity granted permission to use the improved streamflow resulting from the Canadian Treaty reservoirs to the five non–Federal projects in the CEAA.

The current CEAA have the same termination dates as the CSPE purchase. At that time, the Canadian Entitlement from the first of the Canadian Treaty projects to be operational, Duncan, will need to be delivered to Canada beginning in 1998. The benefits attributed to regulation of Arrow must be delivered beginning in 1999. The benefits attributed to regulation of Mica must be delivered beginning in 2003.

(2) Pacific Northwest Coordination Agreement: The PNCA was executed in 1964 as an important component of U.S. plans for the comprehensive development and management of water resources for maximum sustained benefit for the public good. A basic concept of PNCA is that all parties coordinate the planning and operation of the PNW's electric generating and transmission facilities to produce optimum firm power benefits and optimum usable secondary energy generation from the water available for hydroelectric power generation. Because the Treaty assumes a coordinated U.S. operation, the PNCA is important in fully realizing the benefits envisioned by the Treaty. The PNCA expires in 2003.

(3) Pacific Northwest–Southwest Intertie: Construction of the Intertie between the PNW and California, with an initial capacity of 3440 MW, insured that the Canadian Entitlement could be resold in the California market during the early years of Treaty implementation when BPA and the CSPE participants did not need the power. Beginning in 1973, the Entitlement power was gradually withdrawn back to the PNW and completely withdrawn by 1983. The present capacity of the Intertie is approximately 7900 MWs.

As examined in the Entitlement Forecast Report, dated April 1993, estimates of the Canadian Entitlement in 1998 under medium load growth range from 550 to 600 aMW of energy and 1,200 to 1,400 MW of capacity. The actual Canadian Entitlement obligation is computed annually 6 years in advance under the Assured Plan of Operation (AOP) and the Determination of Downstream Power Benefits (DDPB). For the period 1 April through 31 July 1998, the obligation of the U.S. to return Canadian Entitlement resulting from Duncan (about 9 % of the total Entitlement) to Canada is 50.0 aMW of energy and 111.1 MW of capacity as determined in the 1997/98 AOP/DDPB.

The energy is forecast to decrease over the remaining minimum term of the Treaty, from the current 550–600 aMW to about 450 to 500 aMW in 2024. The capacity is expected to remain stable, but could be limited or reduced to zero under Annex B, Paragraph 2, of the Treaty (Capacity Credit Limit) before 2024. A new CEAA, or Allocation Agreements, between the U.S. Entity and the mid–Columbia project owners are needed to establish obligations for Canadian Entitlement delivery following expiration of the current agreements.

2.2 AFFECTED ENVIRONMENT

Areas potentially affected by CEAA alternatives include areas where generation projects may be built/deferred, or areas where generation projects, including hydroelectric projects, may be operated differently. The location of these areas depends, in part, on how much of the generation available to each utility is reduced by the allocation of the Canadian Entitlement obligation to the projects downstream of Treaty storage. The Resource Programs EIS, dated February 1993, addresses issues related to resource acquisitions and will not be repeated here. The focus of this Appendix is on the Columbia River Basin, particularly those areas located downstream of Treaty storage in Canada. The three Treaty projects in Canada are operated under the terms of the Columbia River Treaty and will not be affected by the CEAA alternatives.

The geography and land use of the affected environment in the Pacific Northwest center on the Columbia River system. The area includes most of Washington, Oregon, and Idaho; Montana west of the Rocky Mountains; small areas of Wyoming, Utah, and Nevada; and southeastern British Columbia. The Columbia River and associated tributaries comprise one of the principal economic and environmental resources in the Pacific Northwest. The Columbia River originates in the Rocky Mountains of British Columbia, Canada and flows south to be joined by two major tributaries, the Kootenai and Pend Oreille Rivers, near the U.S. – Canadian border. Another important tributary, the Snake River, originates in the region of Yellowstone National Park in Wyoming and joins the Columbia River 330 miles (531 km) upstream from the mouth, in southeastern Washington. The Columbia continues west, forming the border between Oregon and Washington, and eventually reaching the Pacific Ocean.

The amount of runoff in the system is highly variable. For operational purposes, runoff is usually measured at The Dalles, Oregon. Here the average annual runoff is about 134 MAF (165,356 million m^3), but it has varied from about 78 MAF (96,252 million m^3) to 193 MAF (238,162 million m^3). The average monthly unregulated stream flow at The Dalles range has ranged from about 40,000 cubic feet per second (cfs) (1,133 m^3/s) in winter, to over 800,000 cfs (22,650 m^3/s) in the spring.

In the U.S., major Federal storage reservoirs exist behind Libby, Grand Coulee, Albeni Falls, Hungry Horse, and Dworshak Dams. The three Canadian Treaty dams (Mica, Keenleyside, and Duncan) also provide substantial water storage for the Columbia River Basin. The total usable storage capacity of the Columbia River system is about 42 MAF, or less than a third of the average annual runoff at The Dalles. Hydroelectric projects produce about two–thirds of the total electricity used in the Pacific Northwest.

In addition to major storage reservoirs, the Columbia River system includes many "run–of–river" projects with limited storage developed primarily for navigation and hydropower generation. These projects discharge water at nearly the same rate as the inflow.

The affected environment on the Columbia downstream of Canadian Treaty storage includes six (6) Federal and five (5) non–Federal hydro projects on the Columbia River. The Federal projects are Grand Coulee containing about 5.2 MAF of storage and Chief Joseph, McNary, John Day, The Dalles, and Bonneville which are run–of–river projects. The non–Federal projects, Wells, Rock Island, Rocky Reach, Wanapum, and Priest Rapids are all run–of–river projects located between Chief Joseph and McNary dams Characteristics of these projects are provided in Appendix I, Table 2–1. These large–scale facilities play a key role in the multi–purpose use of the Columbia River system. They include dams and reservoirs, navigation channels and locks, hydroelectric power plants, high–voltage power lines and substations, fish ladders and bypass facilities, irrigation diversions and pumps, parks and recreation facilities, boat launches, lands that are dedicated to the projects, and areas set aside to replace wildlife habitat.

For further information on the Columbia River Basin, please see Appendices I and R.

CHAPTER 3

STUDY METHODS

3.1 INTRODUCTION

The analysis was conducted by BPA staff with substantial input and review by a small subgroup of the Power Work Group. The list of preparers and the subgroup are shown in Chapter 6. Prior to the SOR process, informal meetings occurred where U.S. Entity staff and members of a number of regional utilities discussed potential methods for allocation of the Canadian Entitlement after current agreements expire. These discussions provided the basis for selecting the alternatives examined in this appendix.

3.2 DEVELOPMENT OF ALTERNATIVES

A fundamental premise for allocating the Canadian Entitlement among U.S. parties is that the allocation will be based on the relative amount of downstream power benefits, both average annual usable energy and dependable capacity, accruing to the Federal and non–Federal projects located downstream of Treaty storage. Because the actual obligation to deliver Canadian Entitlement is computed 6 years in advance, the Canadian Entitlement obligation is not known for most years of the proposed term of the new agreements (1998–2024). The alternatives, therefore, are presented as Federal and non–Federal percentages of the Canadian Entitlement obligation.

The determination of the Canadian Entitlement and the resulting allocation are dependent on a number of factors including but not limited to; additional thermal installations which affect the usability of Treaty water, changes in load shape, changes in unit installations at existing hydroelectric projects, and changes in study procedures. Due to changes in the study data and/or procedures, it is expected that relative Federal and non–Federal percentage obligations will change during the period 1998 through 2024. In addition, the Federal and non–Federal percentages for the average annual usable energy and dependable capacity will likely be different as these quantities are computed using different procedures specified by the Treaty.

In order to quantify the potential range of Canadian Entitlement allocation, the subgroup identified four alternatives that account for potential changes Federal and non–Federal percentages:

Alternative 1: The no–action alternative. This alternative essentially maximizes the Federal Obligation while minimizing the non–Federal obligation.

Alternative 2: This alternative was developed considering the factors that would minimize the Federal obligation while maximizing the non–Federal obligation.

Alternative 3: This alternative provides a point between Alternatives 1 and 2.

Alternative 4: This alternative was developed to consider impacts if Federal and non–Federal parties are unable to negotiate new agreements.

The CEAA alternatives are described in Chapter 4.

3.3 EVALUATION OF ALTERNATIVES

In order to evaluate potential environmental energy effects of CEAA alternatives, a version of the System Analysis Model (SAMII) was used that simulated actions of Federal, Investor Owned Utilities, and Generating Public Utilities. SAMII is a monthly energy model that simulates the operation of the PNW hydro and thermal system. The alternatives were analyzed for the period 1998 through 2012 using 200 simulations for each year with random water conditions selected from the 50 year stream flow record (1928 – 1978). For the energy analysis, expected values of flows at The Dalles, and elevations at Grand Coulee and Hungry Horse were examined for Alternatives 1, 2, and 3.

Potential environmental capacity effects of CEAA Alternatives 1, 2, and 3 were examined by analyzing the flows required to generate the entire capacity Entitlement obligation, which assumes that the entire capacity Entitlement obligation is borne by the hydro system. The actual capacity Entitlement return will be made from "system resources" including hydro generation, non–hydro generating facilities, and purchases. Thus, the estimates discussed represent the maximum use of stream flows for return of the capacity Entitlement.

Expected values for Alternative 4 will be within the range examined in Alternatives 1, 2, and 3.

Potential hydro system impacts are examined by analyzing the changes in hydro system operations due to different allocation methodologies. The potential differences in hydro system operations can then be compared to differences evaluated in other sections of the SOR EIS for potential environmental impacts. The Environmental impacts of allocation alternatives to the FCRPS are examined in Section 4.2.

CHAPTER 4

ALTERNATIVES AND THEIR IMPACTS

4.1 DESCRIPTION OF ALTERNATIVES

The allocation of the Canadian Entitlement among U.S. parties will be based on the relative amounts of downstream power benefits accruing on the Federal and non–Federal systems due to Canadian Treaty reservoir operation. The final allocation scheme will be negotiated among the U.S. parties. As discussed in Chapter 3, the following CEAA alternatives were developed anticipating the potential range of options for allocating the Canadian Entitlement in order to provide the environmental review necessary to sign new Allocation Agreements.

Alternatives 1, 2, and 3 are presented as Federal and non Federal percentages of the Canadian Entitlement obligation – these percentages apply to both the capacity and energy components. Although it is unlikely that the obligations ultimately agreed to by the Federal and non–Federal parties will be the same percentage for the capacity and energy components of the Canadian Entitlement, the percentages selected for Alternatives 1, 2, and 3 effectively span the range for both the capacity and energy Entitlement.

4.1.1 CEAA Alternative 1 – Entitlement Allocation: 100 percent Federal, 0 percent non–Federal (No–Action)

Under this alternative, the current Allocation Agreements would expire without replacement. It is assumed that the Federal system would undertake the entire Canadian Entitlement delivery obligation beginning in 1998, while allowing the non–Federal projects to generate with water released from Treaty projects. The non–Federal parties would not be obligated to deliver Canadian Entitlement. This maximizes the Federal obligation (100 percent) and minimizes the non–Federal obligation (0 percent) for both capacity and energy.

Under the no–action alternative, the U.S. Entity has not exercised the authority provided by Article XI of the Treaty to condition the use of improved stream flows resulting from Canadian Treaty storage and will take no action to prevent parties from using the Treaty water. Thus, being given the tacit approval of the U.S. Entity, the non–Federal project owners would continue to generate and keep all downstream power benefits at their projects resulting from Canadian Treaty storage. Although it is unlikely that the parties will take no action, this alternative does provide a bound where the Federal obligation is maximized and the non–Federal obligation is minimized that is useful for evaluating environmental impacts.

4.1.2 CEAA Alternative 2 – Entitlement Allocation: 55 percent Federal, 45 percent non–Federal

Alternative 2 represents the bound where the Federal obligation is minimized and the non–Federal obligation is maximized. The Canadian Entitlement obligation for both capacity and energy is 55 percent Federal and 45 percent non–Federal. This allocation scheme was developed by examining the series of studies that are used to compute the Canadian Entitlement obligation. The percentages roughly approximate the increase in annual average generation (over the 1928 through 1958 historical stream flow record) accruing to the Federal and non–Federal projects as a result of downstream power benefit computations under the Treaty. This allocation alternative assumes that sufficient thermal resources have been installed in the PNW region such that the secondary energy is fully usable. While this situation does not currently exist in the PNW today, it is feasible that the secondary energy could become fully usable before the proposed termination date (2024) of the new allocation agreements.

Although these percentages were developed based on an increase in annual average energy, they effectively bound any potential capacity allocation percentages as well.

4.1.3 CEAA Alternative 3 – Entitlement Allocation: 70 percent Federal, 30 percent non–Federal

Alternative 3 provides a point between Alternatives 1 and 2 for the Federal and Non–Federal obligation. These percentages represent the split of generating capability, or hydraulic head, between the Federal and non–Federal projects on the Columbia river downstream from the Canadian storage projects. In other words, for each unit of water released from Canadian storage, the Federal projects generate approximately 70 percent of the power, and the non–Federal projects about 30 percent.

4.1.4 CEAA Alternative 4 – No Agreement

Alternative 4 assumes U.S. parties negotiate but are unable to reach agreement on an allocation of the Canadian Entitlement between the Federal and non–Federal systems. Under this scenario, the U.S. Entity would exercise its approval authority provided by Article XI of the Treaty and condition the non–Federal parties use of the improved streamflows resulting from Canadian Treaty Storage.

The Treaty does not provide explicit guidance on how the U.S. Entity might implement the authority provided by Article XI of the Treaty. The U.S. Entity has concluded, however, that as a Federal agency it could employ rulemaking to condition the use of improved stream flow and compel the non–Federal project owners to contribute equitably for benefits received from Canadian Treaty storage. While the process and eventual outcome of rulemaking is uncertain, the U.S. Entity anticipates that it would promulgate a rule that obligates non–Federal parties to return a portion of the Canadian Entitlement commensurate with benefits received. It is likely that the outcome of this process would result in Federal and non–Federal obligations that are within the range examined in Alternatives 1, 2, and 3.

4.2 ENVIRONMENTAL EFFECTS OF ALLOCATION ALTERNATIVES

The Federal Columbia River Power System is operated for multiple purposes including irrigation, navigation, flood control, fish and wildlife, and power production. The operation of the power system is ultimately driven by factors not related to the CEAA alternatives. The system operation review addresses alternative operations of the hydro system, referred to as SOSs. To the extent that an SOS allows for hydro system operating flexibility for power needs, different allocation methodologies may result in different hydro system operations with resulting differences in environmental effects. In order to understand the potential environmental effects of allocation alternatives, an evaluation of the differences in hydro system operations between the alternatives is needed and is described in the following paragraphs. These potential differences in hydro system operations can then be compared to differences evaluated in other sections of this EIS for potential environmental effects. The magnitude of the Entitlement is unaffected by the allocation alternatives.

The Treaty specifies that Entitlement deliveries be in equal monthly amounts unless otherwise agreed by the Entities. Because this analysis addresses only the effects of allocation of Entitlement delivery between Federal and non–Federal parties and not the magnitude of the Entitlement per se, this analysis assumes that there is no shaping of energy on a month–to–month basis. Within a month, Entitlement deliveries may be shaped by Canada within the capacity obligation limits unless other arrangements are mutually agreed by the Entities. The following analysis assumes an obligation of 600 aMW of energy and 1400 MW of capacity for all alternatives.

4.2.1 CEAA Alternative 1 – Entitlement Allocation: 100 percent Federal, 0 percent non–Federal (No–Action)

Alternative 1, the no–action alternative, serves as a basis for comparison of the other alternatives. This alternative represents a situation in which no agreements related to the Entitlement are reached with mid–Columbia project owners and the U.S. Entity does not condition use of the improved stream flows by the mid–Columbia project owners and participants. In this alternative it is assumed that the Federal system is responsible for delivery of all of the Entitlement and no arrangements are made for compensation by the mid–Columbia projects. Thus, the Federal system would be required to generate up to an estimated 600 aMW of energy and 1400 MW of capacity for the delivery of the Canadian Entitlement.

SAMII was used to simulate hydro system operations on an energy basis. In this alternative, the Entitlement is delivered from Federal resources. Tables 4–1 through 4–4 (presented at the end of Chapter 4) show results from this alternative to which the other alternatives are compared. Monthly flows at The Dalles are provided due to their importance for the migration of anadromous fish (see Appendix C). Monthly reservoir elevations for Grand Coulee, Libby, and Hungry Horse are presented because of their importance for cultural resources, recreation, and resident fish (see Appendices D, J, and K).

Delivery of the capacity component of the Entitlement was not modeled, however the following figures provide a guide to the approximate magnitude of the capacity Entitlement in terms of hydro system flow. The maximum rate of return, assuming a 1400 MW capacity obligation, would require a flow of approximately 23 kcfs to be used for Entitlement delivery, assuming Federal generation from Grand Coulee downstream. Although the Entitlement is computed based on changes in hydro system operations resulting from Canadian Treaty storage, the actual Entitlement return will be made from "system" resources including hydro generation, non–hydro generating facilities, and purchases. Thus, the estimates discussed represent the maximum use of stream flows for return of the Canadian Entitlement.

Under this alternative, the non–Federal projects which have no seasonal storage capability, would be expected to generate the flows passing through Grand Coulee (the upstream Federal storage project). Because the non–Federal project owners and participants would not have to return the energy or capacity associated with Treaty releases to Canada or to the U.S. Entity, the generation could be used to serve their loads or to displace generation from other resources.

4.2.2 CEAA Alternative 2 – Entitlement Allocation: 55 percent Federal, 45 percent non–Federal

This alternative differs from the no–action alternative in that an Entitlement delivery obligation is assumed by the non–Federal project owners and participants. This means that the mid–Columbia projects would contribute to delivery of the Canadian Entitlement. This does not affect the total obligation of U.S. parties or the terms of delivery of the Canadian Entitlement. Those aspects would remain as described under the no–action alternative. The Federal obligation would be 55 percent of the energy and capacity or 330 aMW of energy and 770 MW of capacity. The non–Federal obligation would be 45 percent of the energy and capacity or 270 aMW of energy and 630 MW of capacity.

Compared to the no–action alternative, Alternative 2 may reduce the amount of resource acquisitions required by the Federal system and increase those required by the non–Federal project owners. For the purposes of these studies, it was assumed that the non–Federal parties would acquire additional combustion turbines to meet the Entitlement obligation and the Federal system would reduce acquisitions, primarily conservation. Tables 4–1 through 4–4 summarize Alternative 2 study results compared to the no–action alternative.

In reviewing study results it is apparent that allocation alternatives had virtually no impact on Columbia River flows or reservoir elevations when evaluating the energy component of the Entitlement. The primary effect of allocation of the energy Entitlement is likely to be on the resources acquired to meet the total load requirements of the parties.

If it is assumed that the capacity obligation is generated on the hydro system, the flow required to produce that capacity can be computed based on water–to–energy conversion factors at each project. Under Alternative 2, the flow needed to generate the capacity Entitlement would be approximately 13 kcfs for the Federal system and 25 kcfs for the non–Federal projects. This means that at the maximum rate of Entitlement return 13 kcfs of flow through the Federal system and 25 kcfs of flow through the non–Federal system could be required to meet the Entitlement obligation. This represents a decrease of 10 kcfs on the Federal system and an increase of 2 kcfs on the non–Federal system when compared to the no–action alternative.

As in the no–action alternative, the actual Entitlement delivery will be made from "system" resources including hydro generation, non–hydro generating facilities and purchases. Thus, the estimates discussed represent the maximum use of stream flows for return of the Canadian Entitlement under Alternative 2.

4.2.3 CEAA Alternative 3 – Entitlement Allocation: 70 percent Federal, 30 percent non–Federal

This alternative differs from the Alternative 2 in the Entitlement delivery obligation assumed by the non–Federal project owners and participants. This does not affect the total obligation of U.S. parties or the terms of delivery of the Canadian Entitlement. Those aspects would remain as described under the no–action alternative. In Alternative 3 the Federal and non–Federal obligations for delivery of the Canadian Entitlement are approximately equal to their proportionate ability to convert water to energy. The proportion attributable to the non–Federal projects is assumed to be the ratio of the average non–Federal water–to–energy conversion factor (assumed to be 25 MW/kcfs) to the total Federal and non–Federal water–to–energy conversion factor (assumed to be 85 MW/kcfs). For each unit of water released from Canadian storage, the Federal plants generate approximately 70 percent of the energy, and the non–Federal plants about 30 percent. The Federal obligation would be 70 percent of the energy and capacity or 420 aMW of energy and 980 MW of capacity. The non–Federal obligation would be 30 percent of the energy and capacity or 180 aMW of energy and 420 MW of capacity.

Compared to the no–action alternative, Alternative 3 may reduce the amount of resource acquisitions required by the Federal system and increase those required by the non–Federal project owners, but less so than Alternative 2. For the purposes of these studies, it was assumed that the non–Federal parties would acquire additional combustion turbines to meet this obligation and the Federal system would reduce acquisitions, primarily conservation. Tables 4–1 through 4–4 present a summary of the Alternative 3 study results compared to the no–action alternative. As shown in the tables, this alternative for allocation of the energy entitlement has no effect on either Columbia River flows or on reservoir elevations.

The flow needed to generate the capacity entitlement would be approximately 16 kcfs on both the Federal and non–Federal systems. This means that at the maximum rate of Entitlement return, 16 kcfs of flow through the hydro system downstream of Grand Coulee could be required to meet the Entitlement obligation. This represents a decrease of 7 kcfs when compared to the no–action alternative.

Although flows in the Columbia River on a monthly average basis may not be affected by the CEAA, the amount of the obligation may affect how non–hydro resources are operated or the amount of resource acquisitions required. Compared to the no–action alternative, Alternative 3 may slightly reduce the amount of resource acquisitions required by the Federal system and increase those required by the non–Federal project owners.

As in the no–action alternative, the actual Entitlement delivery will be made from "system" resources including hydro generation, non–hydro generating facilities and purchases. Thus, the estimates discussed represent the maximum use of stream flows for return of the Canadian Entitlement under Alternative 3.

4.2.4 CEAA Alternative 4 – No Agreement

Alternative 4 assumes the U.S. parties negotiate but are unable to reach agreement on an allocation of the Canadian Entitlement. Under this scenario, the U.S. Entity would employ rulemaking to condition the use of improved stream flow and compel the non–Federal project owners to contribute equitably for benefits received from Canadian Treaty storage.

The U.S. Entity anticipates that it would promulgate a rule that would compel non–Federal parties for an obligation of the Canadian Entitlement that fails within the range of Alternative 1, 2, and 3. In other words, the non–Federal obligation would be between zero and 45 percent of the total Canadian Entitlement obligation, while the Federal obligation would be between 45 and 100 percent. The environmental effects of this alternative, therefore, falls within the range presented in Alternatives 1, 2, and 3.

Alternative 1, the no–action alternative was assumed to be the base case from which Alternatives 2 and 3 were compared. Alternative 4 falls within the range of Alternatives 1, 2, and 3. Results presented in Chapter 4 show that reservoir elevation and river flow changes between the alternatives were minor.

Table 4–1. Change In Average Discharge (kcfs), 15–Year Average (1998–2012)

The Dalles

Average Over Low Water Years (Bottom 10 Percent)

Alternative	SEP	OCT	NOV	DEC	JAN	FEB	MAR	15–Apr	30–Apr	MAY	JUNE	JULY	15–Aug	31–Aug	AVG
Alt 1 (No–Action)	96.9	100.3	113.9	140.4	118.0	118.5	125.2	131.1	149.2	226.7	204.1	101.9	100.1	102.8	132.3
Change Relative to No–Action															
Alt 2 (55 % Fed)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Alt 3 (70 % Fed)	0	0	0	0	0	0	0	0	0	0.1	0	0	0	0	0

Average Over Typical Water Years (Mid 85 Percent)

Alternative	SEP	OCT	NOV	DEC	JAN	FEB	MAR	15–Apr	30–Apr	MAY	JUNE	JULY	15–Aug	31–Aug	AVG
Alt 1 (No–Action)	101.9	112.7	128.3	167.0	187.1	201.1	218.6	256.8	279.5	288.9	288.6	186.6	141.4	117.8	190.0
Change Relative to No–Action															
Alt 2 (55 % Fed)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Alt 3 (70 % Fed)	0	0	0	0	0	−0.1	0.1	−0.1	0	0	0	0.1	0	0	0

Average Over High Water Years (Top 5 Percent)

Alternative	SEP	OCT	NOV	DEC	JAN	FEB	MAR	15–Apr	30–Apr	MAY	JUNE	JULY	15–Aug	31–Aug	AVG
Alt 1 (No–Action)	88.5	131.5	153.5	191.3	220.3	218.1	238.9	256.9	334.1	387.1	463.7	246.4	163.9	144.0	232.3
Change Relative to No–Action															
Alt 2 (55 % Fed)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Alt 3 (70 % Fed)	−0.1	0.1	0	0	0	0	0.1	−0.1	−0.1	0	0	0	0	0	0

Table 4–2. Change In Average Reservoir Elevation (feet) ,15–Year Average (1998–2012)

Grand Coulee

Average Over Low Water Years (Bottom 10 Percent)

Alternative	SEP	OCT	NOV	DEC	JAN	FEB	MAR	15–Apr	30–Apr	MAY	JUNE	JULY	15–Aug	31–Aug	AVG
Alt 1 (No–Action)	1288.9	1289.4	1290.0	1289.7	1289.0	1289.0	1282.0	1282.0	1283.0	1282.8	1288.1	1289.9	1290.0	1290.0	1287.7
Change Relative to No–Action															
Alt 2 (55 % Fed)	–0.1	0	0	0	0	0	0	0	0	0.1	0	0	0	0	0
Alt 3 (70 % Fed)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Average Over Typical Water Years (Mid 85 Percent)

Alternative	SEP	OCT	NOV	DEC	JAN	FEB	MAR	15–Apr	30–Apr	MAY	JUNE	JULY	15–Aug	31–Aug	AVG
Alt 1 (No–Action)	1288.3	1289.0	1290.0	1289.3	1288.9	1285.0	1261.5	1248.9	1235.8	1258.9	1286.9	1290.0	1290.0	1290.0	1279.1
Change Relative to No–Action															
Alt 2 (55 % Fed)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Alt 3 (70 % Fed)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Average Over High Water Years (Top 5 Percent)

Alternative	SEP	OCT	NOV	DEC	JAN	FEB	MAR	15–Apr	30–Apr	MAY	JUNE	JULY	15–Aug	31–Aug	AVG
Alt 1 (No–Action)	1288.9	1289.9	1290.0	1289.5	1290.0	1284.9	1255.9	1236.7	1223.0	1253.0	1290.0	1290.0	1290.0	1290.0	1278.0
Change Relative to No–Action															
Alt 2 (55 % Fed)	0	0	0	0	0	0	–0.1	–0.1	0	0	0	0	0	0	0
Alt 3 (70 % Fed)	0	0	0	0	0	0	–0.1	–0.1	0	0	0	0	0	0	0

Table 4–3. Change In Average Reservoir Elevation (feet), 15–Year Average (1998–2012)

Libby

Average Over Low Water Years (Bottom 10 Percent)

Alternative	SEP	OCT	NOV	DEC	JAN	FEB	MAR	15–Apr	30–Apr	MAY	JUNE	JULY	15–Aug	31–Aug	AVG
Alt 1 (No–Action)	2455.6	2455.4	2444.9	2410.7	2402.6	2395.8	2379.9	2375.3	2372.5	2401.6	2431.9	2441.2	2442.3	2443.1	2419.6
Change Relative to No–Action															
Alt 2 (55 % Fed)	0.1	–0.1	–0.1	0	0	–0.1	–0.1	–0.1	–0.1	–0.1	0	0	0	0	0
Alt 3 (70 % Fed)	0	0	0	0	0	0	0	0	0	–0.1	–0.1	–0.1	–0.1	–0.1	0

Average Over Typical Water Years (Mid 85 Percent)

Alternative	SEP	OCT	NOV	DEC	JAN	FEB	MAR	15–Apr	30–Apr	MAY	JUNE	JULY	15–Aug	31–Aug	AVG
Alt 1 (No–Action)	2455.7	2455.9	2444.9	2410.9	2373.0	2336.9	2322.6	2323.1	2330.1	2385.3	2443.4	2457.1	2457.9	2457.9	2406.2
Change Relative to No–Action															
Alt 2 (55 % Fed)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Alt 3 (70 % Fed)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Average Over High Water Years (Top 5 Percent)

Alternative	SEP	OCT	NOV	DEC	JAN	FEB	MAR	15–Apr	30–Apr	MAY	JUNE	JULY	15–Aug	31–Aug	AVG
Alt 1 (No–Action)	2454.2	2455.3	2444.6	2410.8	2358.0	2306.0	2287.0	2276.0	2287.0	3490.0	2459.0	2459.0	2459.0	2459.0	2397.6
Change Relative to No–Action															
Alt 2 (55 % Fed)	–0.1	–0.1	0	0	0	0	0	0	0	0	0	0	0	0	0
Alt 3 (70 % Fed)	0.1	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 4–4. Change In Average Reservoir Elevation (feet), 15–Year Average (1998–2012)

Hungry Horse

Average Over Low Water Years (Bottom 10 Percent)

Alternative	SEP	OCT	NOV	DEC	JAN	FEB	MAR	15–Apr	30–Apr	MAY	JUNE	JULY	15–Aug	31–Aug	AVG
Alt 1 (No–Action)	3544.4	3540.7	3536.2	3530.6	3521.4	3503.0	3470.5	3454.8	3443.5	3481.1	3500.8	3504.3	3502.5	3499.8	3506.5
Change Relative to No–Action															
Alt 2 (55 % Fed)	0	−0.1	−0.1	−0.1	−0.1	0	−0.1	−0.1	0	−0.1	−0.1	−0.2	−0.2	−0.2	0
Alt 3 (70 % Fed)	0	0	−0.1	−0.1	0	0.1	0.1	0.3	0.2	0	0.1	0	0.1	0	0

Average Over Typical Water Years (Mid 85 Percent)

Alternative	SEP	OCT	NOV	DEC	JAN	FEB	MAR	15–Apr	30–Apr	MAY	JUNE	JULY	15–Aug	31–Aug	AVG
Alt 1 (No–Action)	3545.6	3544.3	3543.5	3540.4	3531.6	3516.6	3497.6	3488.1	3479.6	3516.4	3549.0	3555.3	3554.8	3553.9	3531.1
Change Relative to No–Action															
Alt 2 (55 % Fed)	0	0	0	0	0	0	0	0.1	0	0	0	0	0	0	0
Alt 3 (70 % Fed)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0	0	0	0	0	0	0

Average Over High Water Years (Top 5 Percent)

Alternative	SEP	OCT	NOV	DEC	JAN	FEB	MAR	15–Apr	30–Apr	MAY	JUNE	JULY	15–Aug	31–Aug	AVG
Alt 1 (No–Action)	3543.3	3545.8	3547.5	3543.6	3534.6	3520.5	3500.8	3488.6	3478.6	3520.9	3553.9	3560.0	3560.0	3560.0	3534.2
Change Relative to No–Action															
Alt 2 (55 % Fed)	−0.1	−0.1	−0.1	−0.1	−0.1	−0.1	−0.1	0	−0.1	0	0	0	0	0	0
Alt 3 (70 % Fed)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0	0	0	0	0	0	0.1

CHAPTER 5

COMPARISON OF ALTERNATIVES

5.1 CONCLUSION

Potential changes in hydro system operations for four alternative allocation methods have been examined. The maximum flows required for return of the Canadian Entitlement by the Federal system and non–Federal projects have been described for each of the alternatives.

The greatest effect of the allocation agreements may be on resource acquisitions by the Federal and non–Federal parties. The obligation to return the Entitlement differs among the alternatives examined, and therefore the load each party is required to serve can be affected. Environmental effects of resource acquisitions were examined in detail (for Federal and non–Federal parties) in the Resource Programs EIS and are therefore not repeated here.

Alternative 1, the No–Action Alternative, was assumed to be the base case with which Alternatives 2 and 3 were compared. Alternative 4 falls within the range of Alternatives 1, 2, and 3. Results presented in Chapter 4 show that reservoir elevation and river flow changes among the alternatives were minor.

The SOR EIS has examined in detail a number of alternative hydro system operating strategies to enhance a variety of non–power uses of the Columbia River system and evaluated the environmental effects of each. The discussion presented in this section on allocation alternatives is intended to provide the reader with estimates of the magnitude of the options involved, in terms of flow, to compare with the environmental analyses and impacts presented elsewhere in this report. Canadian Entitlement deliveries will occur within the hydro system operating bounds ultimately defined by this EIS.

5.2 PREFERRED ALTERNATIVE

The SOR agencies have selected **CEAA Alternative 3** – Entitlement Allocation: 70 percent Federal and 30 percent non–Federal as the preferred alternative. This alternative most closely represents the expected outcome of negotiations between the U.S. Entity and non–Federal utilities for allocation of the Canadian Entitlement.

Since the determination of the Canadian Entitlement and the resulting allocation are dependent on a number of factors, the relative Federal and Non–Federal percentage obligations will change during the proposed contract period 1998 through 2024. In addition, the Federal and non–Federal percentages for the capacity and energy allocation will likely be different as these quantities are computed using different procedures specified by the Treaty.

The expected range of the Federal and non–Federal percentage allocation during the life of the proposed contract will probably be 70 to 75% Federal and 25 to 30% non–Federal. Factors that cannot be predicted at this time could cause the percentage allocations to be outside the expected range.

CEAA alternatives 1 and 2, however, effectively span the range of potential Federal and non–Federal percentage obligations for both the capacity and energy Entitlement. As this Appendix and the SOR Documents have demonstrated, there are no significant impacts to the Environment from any of the CEAA alternatives.

CHAPTER 6

LIST OF PREPARERS

Table 6–1. List of Preparers, Bonneville Power Administration

Name	Education/Years of Experience	Experience and Expertise	Role In Preparation
Cynthia Horvath	Masters in Public Health (Statistics) 14 Years	System Analysis Model (SAM)	SAM Analysis
Pam Kingsbury	M.S. Chemical Oceanography 15 years	Hydro Operations, EIS Preparation, Columbia River Treaty Implementation	Power System Analysis, Document Preparation
Rick Pendergrass	B.S. Civil Engineering 8 Years	System Analysis Modeling, Columbia River Treaty Implementation/Canadian Entitlement Allocation Agreements	Document Preparation

Table 6–2. List of Work Group Members (Power Work Group – Sub Group)

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CHAPTER 7

GLOSSARY

Acre–foot: The volume of water that will cover an area of one acre to a depth of one foot (326,000 gallons or 0.5 second foot days).

Anadromous fish: Fish, such as salmon or steelhead trout, that hatch in freshwater, migrate to and mature in the ocean, and return to freshwater as adults to spawn.

Assured Operating Plan (AOP): The AOP defines the rule curves and other operating parameters to guide the operation of the Canadian Treaty projects for optimum power generation downstream in Canada and the U.S.. As prescribed by the Treaty, the AOP is prepared six years in advance of the actual operating year.

Average Annual Generation: The average amount of energy produced over a one–year period. For purposes of Treaty benefit determinations, the average output of hydroelectric projects is currently based on hydroregulation studies using historical flows experienced during the period 1928–58, as modified by appropriate irrigation depletions.

Average Annual Usable Energy: That portion of the average annual energy production of the U.S. base system which is usable as defined by Annex B to the Treaty, specifically firm energy, plus thermal displacement energy, plus up to 40 percent of remaining energy.

Average megawatt (aMW): The average amount of energy (in megawatts) supplied or demanded over a specified period of time; equivalent to the energy produced by the continuous operation of one megawatt of capacity over the specified period.

Base System: The plants, works and facilities listed in the table in Annex B of the Treaty, as enlarged from time to time by the installation of additional generating facilities, together with any projects which may be constructed on the main stem of the Columbia River in the U.S. (Treaty Article I and Annex B). The table in Annex B is in essence the 1961 Columbia River hydropower system.

Canadian Entitlement Allocation Agreements: Contracts that specify how much power is to be provided by five mid–Columbia projects as a result of increased flows made possible by the Columbia River Treaty projects.

Canadian Entitlement: Canada's share of hydropower generated at downstream projects by the use of the Columbia River Treaty projects.

Capacity: The maximum sustainable amount of power that can be produced by a generating resource at specified times under specified conditions or carried by a transmission facility; also, the maximum rate at which power can be saved by a non generating resource.

Capacity Credit: The dependable hydroelectric capacity credited to Canadian storage as calculated in accordance with Annex B to the Treaty.

Capacity Credit Limit: The limit on the capacity credit described in Treaty Annex B (2) and in the Protocol to the Treaty, paragraph IX(2). This limits to the capacity credit to no more than the difference in firm load carrying capabilities with and without Canadian Treaty storage.

Columbia River Treaty: A Treaty between the U.S. and Canada allowing the construction and coordinated operation of Libby Dam in the U.S., and Mica, Duncan, and Keenleyside (Arrow Lakes) Dams in Canada.

Columbia Storage Power Exchange (CSPE): A non–profit corporation of 11 Northwest utilities that issued revenue bonds to purchase the Canadian Entitlement and sell it to 41 Northwest utilities through a Bonneville Power Administration exchange agreement.

Content: An amount of water stored in a reservoir, usually expressed in terms of KSFD or MAF.

Coordinated operation: The operation of interconnected electrical systems to achieve greater reliability and economy; as applied to hydro resources, the operation of a group of hydro plants to obtain optimal power benefits.

Critical period: That portion of the historical 50–year stream flow record which, when combined with the drafting of all storage reservoirs from full to empty, would produce the least amount of energy shaped to seasonal load patterns.

Critical water: Stream flows which occurred during the critical period.

Cubic feet per second (cfs): A measurement of water flow representing one cubic foot of water moving past a given point in one second. One cfs is equal to 7.48 gallons per second and 0.028 m^3 per second. A thousand cubic feet per second is abbreviated as kcfs.

Demand: The rate at which electric energy is delivered to or by a system; usually expressed in kilowatts or megawatts over a designated period of time.

Dependable Capacity: The load–carrying ability of a power plant or system under adverse conditions for the time interval and period specified when related to the characteristics of the load to be supplied. For purposes of Treaty computations, dependable hydroelectric capacity to be credited to Canadian storage is defined as the difference in average rate of generation during the critical periods with and without Canadian storage divided by the average of the monthly load factors during the critical period of the Pacific Northwest area.

Determination of Downstream Power Benefit (DDPB): The calculation of downstream power benefits in the U.S. resulting from Canadian Treaty Storage that is made annually in conjunction with the Assured Operating Plan.

Discharge: Volume of water flowing at a given time, usually expressed in cubic feet per second.

Displacement: The substitution of less–expensive energy generation for more–expensive energy generation (usually hydroelectric energy transmitted from the Pacific Northwest or Canada is substituted for more expensive coal and oil–fired generation in California). Such displacement usually means that a thermal plant can reduce or shut down its production, saving money and often reducing air pollution.

Downstream Power Benefit: The difference in the average annual usable energy and dependable capacity capable of being generated in the U.S. with and without the use of Canadian Treaty storage.

Draft: Release of water from a storage reservoir, usually measured in feet of reservoir elevation.

Elevation: Height in feet above sea level. Usually refers to reservoir forebay; used interchangeably with content, because a forebay elevation implies a specific reservoir content. Tail water level is also expressed as an elevation.

Energy: Average power production over a stated interval of time, expressed in kilowatt–hours, megawatt–hours, average kilowatts, or average megawatts.

Entities: The entities designated by Canada and the U.S. under Article XVI of the Treaty to formulate and carry out the operating arrangements necessary to implement the Treaty.

> Canadian Entity – The Canadian Entity is the British Columbia Hydro and Power Authority.
>
> United States Entity – The United States Entity is composed of the Administrator of the Bonneville Power Administration and the Division Engineer of the North Pacific Division, Corps of Engineers. The Administrator is designated as Chairman of the United States Entity.

Firm energy: The amount of energy that can be generated given the region's worst historical water conditions. It is energy produced on a guaranteed basis.

Firm energy load carrying capability (FELCC): The amount of energy the region's generating system, or an individual utility or project, can be called on to produce on a firm basis during actual operations. FELCC is made up of both hydro and non–hydro resources, including power purchases.

Flow: The volume of water passing a given point per unit of time. Same as stream flow.

Forebay: The portion of a reservoir at a hydroelectric plant that is immediately upstream of a dam or powerhouse.

Forebay elevation: Height of top of the forebay above sea level.

Generation: Production of electric energy from other forms of energy; also refers to amount of electric energy produced.

Headwater benefits: Gains in usable downstream energy as a result of upstream storage.

Historical stream flow record: The unregulated stream flow data base of the 50 years beginning in July 1928; data are modified to adjust for factors such as irrigation depletions and evaporations for the particular operating year being studied.

Hydraulic Head: The vertical distance between the surface of the reservoir and the surface of the river immediately downstream from the powerhouse. Head is the difference between forebay and tail water elevations.

Hydroelectricity: The production of electric power through use of the gravitational force of falling water.

Inflow: Water that flows into a reservoir or forebay during a specified period.

KAF: A thousand acre feet; same as .504 thousand second foot days.

KCFS: A measurement of water flow equivalent to 1,000 cubic feet of water passing a given point for an entire second.

KSFD: A volume of water equal to 1,000 cubic feet of water flowing past a point for an entire day. Same as 1.98 KAF.

Load: The amount of electric power or energy delivered or required at any specified point or points on a system. Load originates primarily at the energy–consuming equipment of customers.

Load shaping: The adjustment of storage releases so that generation and load are continuously in balance.

MAF: Million acre feet. The equivalent volume of water that will cover an area of one million acres to a depth of one foot. One MAF equals 1,000 KAF.

Mainstem: The principal river in a basin, as opposed to the tributary streams and smaller rivers that feed into it.

Megawatt (MW): A unit of electric power equal to one million watts, or one thousand kilowatts.

Megawatt–hour (MWh): A unit of electrical energy equal to one megawatt of power applied for one hour.

Mid–Columbia: The section of the Columbia River from the Canadian border to its junction with the Snake River.

Nonpower operating requirements: Operating requirements at hydroelectric projects that pertain to navigation, flood control, fish and wildlife, recreation, irrigation, and other nonpower uses of the river.

Northwest Power Pool Coordinating Group: An operating group made up of BPA, the Corps, Reclamation, and public and private generating utilities in the Northwest. One of the group's functions is administering the Pacific Northwest Coordination Agreement.

Operating Committee: The Operating Committee is the element of the Columbia Treaty Organization that is responsible for making the system regulation studies, preparing the operating plans, insuring that the plans are carried out, and performing other duties as required by the Entities.

Operating requirements: Guidelines and limits that must be followed in the operation of a reservoir or generating project. These requirements may originate from authorizing legislation, physical plant limitations, environmental impact analysis or input from government agencies and other entities representing specific river uses. Operating requirements are submitted annually to the Northwest Power Pool by project owners for planning purposes.

Outflow: The volume of water per unit of time discharged at a hydroelectric project.

Pacific Northwest Coordination Agreement: A binding agreement among BPA, the Corps, Reclamation, and the major hydro generating utilities in the Pacific Northwest that stemmed from the Columbia River Treaty. The Agreement specifies a multitude of operating rules, criteria, and procedures for coordinating operation of the Pacific Northwest hydropower system for optimal power production. It directs operation of major generating facilities as though they belonged to a single owner.

Peak load: The maximum electrical demand in a stated period of time. It may be the maximum instantaneous load or the maximum average load within a designated period of time.

Project: Run–of–river or storage dam and related facilities; also a diversion facility.

Project outflow: The volume of water per unit of time released from a project. Same as discharge and outflow.

Protocol: A document accompanying an exchange of notes dated 22 January 1964 which clarifies certain particulars of the Treaty. The Protocol has the same force as the Treaty itself.

Refill: The point at which the hydro system is considered "full" from the seasonal snow melt runoff. Also, refers to the annual process of filling a reservoir.

Reregulating reservoir: A reservoir located downstream from a hydroelectric peaking plant having sufficient pondage to store the widely fluctuating discharges from the peaking plant and release them in a relatively uniform manner downstream.

Reregulation: Storing erratic discharges of water from an upstream hydroelectric plant and releasing them uniformly from a downstream storage plant.

Reservoir content: See content and reservoir storage.

Reservoir draft rate: The rate at which water, released from storage behind a dam, reduces the elevation of the reservoir.

Reservoir elevation: The height above sea level of the water stored behind a dam. Same as forebay elevation.

Reservoir storage: The volume of water in a reservoir at a given time. Same as reservoir content. Reservoir storage implies a reservoir elevation. Tables are used to convert content to elevation at each reservoir.

Resident fish: Fish species that reside in freshwater throughout their lives.

Run–of–river dams: Hydroelectric generating plants that operate based only on available inflow and a limited amount of short–term storage (daily/weekly pondage).

Spill: Water passed over a spillway without going through turbines to produce electricity. Spill can be forced, when there is no storage capability and flows exceed turbine capacity, or planned, for example, when water is spilled to enhance juvenile fish survival.

Storage energy: The energy equivalent of water stored in a reservoir above normal bottom elevation.

Storage reservoirs: Reservoirs with space for retaining water from the annual high–water season to the following low–water season. Careful scheduling of reservoir refill serves to prevent floods in high runoff years. Retained water is released as necessary for multiple uses — power production, fish passage, irrigation, and navigation.

Stream flow: The rate at which water passes a given point in a stream, usually expressed in cubic feet per second (cfs).

Tail water: Water immediately below the power plant. Tail water elevation refers to the level of that water.

Thermal resource: Electrical generating means that rely on conventional fuels such as coal, oil, and gas.

Transmission: Transporting electric energy in bulk from one point to another in the power system rather than to individual customers.

Transmission grid: An inter–connected system of electric transmission lines and associated equipment for transferring electric energy in bulk.

Usable storage capacity: The portion of the reservoir storage capacity in which water normally is stored, or from which water is withdrawn for beneficial uses, in compliance with operating agreements.

Watt: A unit of electrical power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor. It is analogous to horsepower or foot–pounds per minute of mechanical power. One horsepower is equivalent to approximately 746 watts. A kilowatt equals 1,000 watts, a megawatt equals 1,000,000 watts.

References

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3. Draft Delivery of Canadian Entitlement EIS, February 1994, prepared by Bonneville Power Administration.

4. Resource Program EIS, February 1993, prepared by Bonneville Power Administration.

5. Columbia River Treaty, Assured Operating Plan and Determination of Downstream Power Benefits, for operating year 1997–98, October 1992, prepared by the Columbia River Treaty Operating Committee.