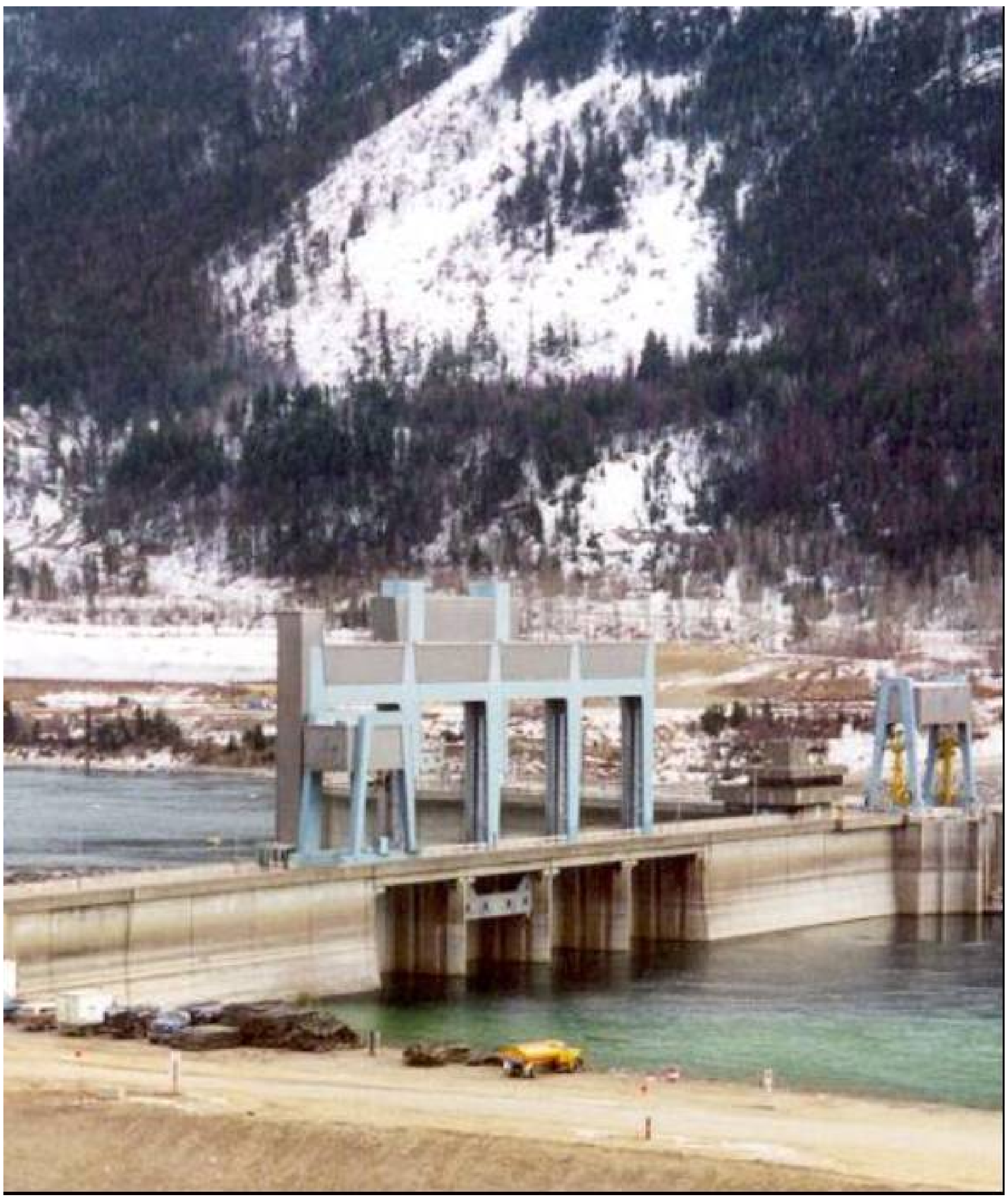
COLUMBIA RIVER TREATY

PRINCIPLES AND PROCEDURES

FOR PREPARATION AND USE OF

HYDROELECTRIC OPERATING PLANS

FOR CANADIAN TREATY STORAGE



October 2003

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Columbia River Treaty

PRINCIPLES AND PROCEDURES

For Preparation And Use Of

Hydroelectric Operating Plans

For Canadian Treaty Storage

Prepared by the

Columbia River Treaty Operating Committee

October 2003

COLUMBIA RIVER TREATY ENTITY AGREEMENT ON THE PRINCIPLES AND PROCEDURES FOR PREPARING AND IMPLEMENTING HYDROELECTRIC OPERATING PLANS FOR OPERATION OF CANADIAN TREATY STORAGE

Paragraph 9, Annex A and paragraph 5, Annex B of the Columbia River Treaty between Canada and the United States of America (Treaty) require that the Entities develop an Assured Operating Plan for operating of Canadian storage for the next succeeding five years. Article XIV 2.(k) of the Treaty provides that the Entities may develop one or more Detailed Operating Plan for each year's actual operation.

The attached Principles and Procedures document dated October 2003 reflects the methodologies used by the Entities in the development of the most recent hydroelectric operating plans and determination of downstream power benefits.

The Columbia River Treaty Operating Committee is directed to record any changes from the Principles and Procedures document reflecting the methodology used in the development of future hydroelectric operating plans and determination of downstream power benefits in appendices to those documents, and to this document. Such changes will be incorporated in future revisions of this Principles and Procedures document when any one change or accumulation of changes becomes, in the opinion of the Committee, significant.

This agreement may be cancelled on thirty (30) calendar days' written notice by either Entity. Following such notice by either Entity, the Entities shall endeavor to negotiate in good faith revisions to any provisions in the Principles and Procedures document that gave rise to the notice of cancellation.

In witness thereof, the Entities have caused this agreement to be executed.

Executed for the Canadian Entity this 16th day of December, 2003.

By
Larry I. Bell
Chair

Executed for the United States Entity this 25th day of November 2003.

By
Stephen J. Wright
Chairman

By
Brigadier General William T. Grisoli
Member

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1 INTRODUCTION

1.1 AUTHORITY AND PURPOSE

This document was produced by the Columbia River Treaty Operating Committee with the authorization of the United States (U.S.) and Canadian Entities as a guide for the preparation and use of hydroelectric operating plans for Canadian Treaty Storage. The last such document, "Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans for Canadian Treaty Storage" (POP), dated December 1991, was agreed to by the Entities on 13 December 1991.

This revision includes changes resulting from:

(1) the "Columbia River Treaty Entity Agreement on Resolving the Dispute on Critical Period Determination, the Capacity Entitlement for the 1998/99, 1999/00, and 2000/01 AOP/DDPB's, and Operating Procedures for the 2001/02 and Future AOP's", dated 29 August 1996;

(2) the "Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for April 1, 1998 Through September 15, 2024 between the Canadian Entity and the U.S. Entity Made This 20th Day of November 1996", as superceded by the Entity Agreement of the same name of 29 March 1999;

(3) the "Columbia River Treaty Entity Agreement Coordinating the Operation of the Libby Project With the Operation of Hydroelectric Plants on the Kootenay River and Elsewhere in Canada," dated 16 February 2000; and

(4) other changes that reflect current planning and operating practices, including:

- Clarification of the definitions and procedures for including loads and resources in the hydroregulation studies;
- Clarification to the procedures for determining thermal displacement energy in the Determination of Downstream Power Benefits;
- Revisions to procedures for calculating Assured Refill Curves and Variable Refill Curves;
- Non-power requirements and updated plant data for Base System projects;
- Use of the Treaty Storage Regulation to determine composite Canadian Treaty Storage operation, including proportional draft requirements, for actual operations; and
- Modifications to the procedures for operating the Brownlee project in system regulation studies.

The December 1991 version of this document was developed to guide the Entities in the preparation of the 1996-97 and 1997-98 Assured Operating Plans, preparation and use of the 1992-93 Detailed Operating Plan and the use of the 1991-92 Detailed Operating Plans. Later hydroelectric operating plans incorporated further changes, as described generally in Section 1.1 and as detailed in each plan. All changes to date are documented herein. As such, this document reflects the principles and procedures used in the development of the 2005-06 Assured Operating Plan and the 2003-04 Detailed Operating Plan.

This document, hereinafter referred to as "Principles and Procedures", shall be used to develop and implement all subsequent operating plans, except as may be specifically documented in each operating plan and/or revisions to the Principles and Procedures. This agreement will be formalized in an Entity Agreement adopting these Principles and Procedures.

The following table shows the application of prior versions of the Principles and Procedures.

Table 1

Historical Development of Principles and Procedures Document

Document Version	Associated Assured Operating Plans	Associated Detailed Operating Plans
25 July 1967	1969/70 through 1983/84	1969/70 through 1978/79
1 May 1979	1984/85 through 1987/88	1979/80 through 1983/84
31 May 1983	1988/89 through 1995/96	1984/85 through 1990/91
Nov 1990	None	Preparation of the 1991/92 plan
Dec 1991	1996/97 through 2005/06	Implementation of 1991/92 plan 1992/93 through 2003/04

1.2 SCOPE

The Columbia River Treaty directs that the operating arrangements necessary to implement the Treaty will be formulated and carried out by the Entities designated by the U.S. and Canada. Article XIV 2. of the Treaty specifies that the powers and duties of the Entities include, among other things:

> “(h) preparation of the hydroelectric operating plans and the flood control operating plans for the Canadian storage together with determination of the downstream power benefits to which Canada is entitled”; and
>
> “(k) preparation and implementation of detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under the plans referred to in Annexes A and B”.

Guidance for flood control planning and operations is provided in the Columbia River Treaty Flood Control Operating Plan, dated May 2003 (the “Flood Control Operating Plan”) submitted by the U.S. Entity in accordance with Annex A, paragraph 5 of the Treaty. Guidance for the coordination of the Libby project with hydroelectric projects downstream from Libby in Canada is provided by the Libby Coordination Agreement (see reference at Section 1.3 (5)(f)). Guidance for the preparation of hydroelectric operating plans for Canadian Treaty Storage and for the calculation of downstream benefits is provided in this document. In addition, these Principles and Procedures, together with the Flood Control Operating Plan, detail the steps necessary to prepare and implement the detailed operating plans. This document will be reviewed periodically and revised as necessary.

Three operating plans shall be prepared annually. An Assured Operating Plan will be prepared for the sixth succeeding operating year which, with previous plans, will assure both

Entities of the manner of operation of Canadian Treaty Storage in advance for the next succeeding five years and will also be the basis for computing Downstream Power Benefits for the corresponding operating year. Once the Downstream Power Benefits are agreed to they shall not be changed even though the operating plan, or data on which it was developed, may change. Immediately prior to each operating year, a Detailed Operating Plan will be developed from the Assured Operating Plan for that operating year. The Detailed Operating Plan may reflect any changes mutually agreed by the Entities. The Detailed Operating Plan will serve as a guide and provide criteria for actual operation of the Canadian Treaty Storage during the immediately ensuing operating year. Immediately prior to each operating year, the U.S. Entity will develop a Libby Operating Plan as an amended Attachment to the Libby Coordination Agreement. The Entities have adopted the 1 August through 31 July period as the operating year.

1.3 REFERENCES

(1) Columbia River Treaty dated 17 January 1961, and its allied documents, pertaining to the preparation and use of operating plans, especially:

- (a) Article IV - Operation by Canada; paragraphs 1 and 2;
- (b) Article V - Entitlement to Downstream Power Benefits; paragraphs 1 and 2;
- (c) Article VI - Payment for Flood Control; paragraphs 3 and 5;
- (d) Article VII - Determination of Downstream Power Benefits;
- (e) Article XII - Kootenai River Development; paragraph 6;
- (f) Article XIV - Arrangements for Implementation; paragraph 2;
- (g) Annex A - Principles of Operation; and
- (h) Annex B - Determination of Downstream Power Benefits.

(2) Intentionally left blank (previously referred to the now expired Terms of Sale Agreement)

(3) Protocol - Annex to Exchange of Notes dated 22 January 1964 pertaining to the preparation and use of operating plans (“Protocol”); especially paragraphs V, VII, VIII, IX and X.

(4) Columbia River Treaty Flood Control Operating Plan dated May 2003, as amended.

(5) Entity Agreements as follows:

- (a) Columbia River Treaty Entity Agreement on Principles for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, dated 20th July (U.S. Entity) and 28th July (Canadian Entity), 1988;
- (b) Columbia River Treaty Entity Agreement on Changes to Procedures for Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, dated 28th July (Canadian Entity) and 12th August (U.S. Entity), 1988;
- (c) Columbia River Treaty Entity Agreement on Resolving the Dispute on Critical Period Determination, the Capacity Entitlement for the 1998/99, 1999/00, and 2000/01 AOP/DDPB’s, and Operating Procedures for the 2001/02 and Future AOP’s, dated 29 August 1996;
- (d) Agreement on Disposals of the Canadian Entitlement within the United States for April 1, 1998 through September 15, 2024, dated 29 March 1999;

(e) Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for April 1, 1998 through September 15, 2024 between the Canadian Entity and the United States Entity, dated 29 March 1999; and

(f) Columbia River Treaty Entity Agreement Coordinating the Operation of the Libby Project with the Operation of Hydroelectric Plants on the Kootenay River and Elsewhere in Canada, dated 16 February 2000.

1.4 DEFINITIONS

The following terms are defined in Article I of the Columbia River Treaty and have the same meanings in this document. For convenience these definitions are repeated below:

(1) "**average critical period load factor**" means the average of the monthly load factors during the critical stream flow period;

(2) "**Base System**" means the plants, works and facilities listed in the table in Annex B as enlarged from time to time by the installation of additional generating facilities, together with any plants, works or facilities which may be constructed on the main stem of the Columbia River in the United States of America; (for convenience portions of the table in Annex B are included as Table 5 in this document. Table 5 also shows the current projection of the enlarged capacity installation for these projects.)

(3) "**Canadian storage**" means the storage provided by Canada under Article II;

(4) "**critical stream flow period**" means the period, beginning with the initial release of stored water from full reservoir conditions and ending with the reservoirs empty, when the water available from reservoir releases plus the natural stream flow is capable of producing the least amount of hydroelectric power in meeting system load requirements;

(5) "**consumptive use**" means use of water for domestic, municipal, stock-water, irrigation, mining or industrial purposes but does not include use for generation of hydroelectric power;

(6) "**dam**" means a structure to impound water, including facilities for controlling the release of the impounded water;

(7) "**entity**" means an entity designated by either Canada or the United States of America under Article XIV and includes its lawful successor;

(8) "**International Joint Commission**" means the Commission established under Article VII of the Boundary Waters Treaty, 1909, or any body designated by the United States of America and Canada to succeed to the functions of the Commission under this Treaty;

(9) "**maintenance curtailment**" means an interruption or curtailment which the entity responsible therefore considers necessary for purposes of repairs, replacements, installations of equipment, performance of other maintenance work, investigations and inspections;

(10) "**monthly load factor**" means the ratio of the average load for a month to the integrated maximum load over one hour during that month;

(11) "**normal full pool elevation**" means the elevation to which water is stored in a reservoir by deliberate impoundment every year, subject to the availability of sufficient flow;

(12) "**ratification date**" means the day on which the instruments of ratification of the Treaty are exchanged;

(13) "**Treaty**" means this Treaty and its Annexes A and B;

(14) "**useful life**" means the time between the commencement of operation of a dam or facility and the date of its permanent retirement from service by reason of obsolescence or wear and tear which occurs notwithstanding good maintenance practices.

In addition, the following terms used within this document, shall mean:

(15) "**Actual Energy Regulation**" shall mean the hydro regulation study performed for implementation of annual Pacific Northwest Coordination Agreement or successor operations;

(16) "**Canadian Treaty Storage**" shall have the same meaning as "**Canadian storage**" as defined in Article I(c) of the Treaty;

(17) "**Load of the Pacific Northwest Area"** as described in Annex B, paragraph 7, and referred to in Protocol paragraph IX, is equal to the amount of electric power used to serve firm load in the Pacific Northwest Area as that area is defined in Annex B. "**Firm load**" in the Pacific Northwest Area is the load for which resources have been or must be acquired to serve that load;

(18) "**Firm energy load carrying capability**" of a system is the maximum generation, shaped the same as the firm energy load of that system, that the system can produce during its critical period;

(19) "**Month"** shall mean a calendar month excluding the months of April and August and including each of the following periods:

(a) 1 April to 15 April;
(b) 16 April to 30 April;
(c) 1 August to 15 August; and
(d) 16 August to 31 August;

(20) "**Pacific Northwest Area**", as described in Annex B paragraph 7, means Oregon, Washington, Idaho, and Montana west of the Continental Divide but shall exclude areas served on the Treaty ratification date by the California Oregon Power Company and the Utah Power and Light Company;

(21) "**Pacific Northwest Coordination Agreement**" means the agreement of that title dated 18 July 1997, as amended, amongst several of the owners and operators of the U.S. Columbia Basin hydroelectric projects, except when referred to in this document as the "1964 Pacific Northwest Coordination Agreement," it means the agreement dated 15 September 1964;

(22) "**storage**" means the water content in a reservoir which may be released to provide flood control space or for regulating stream flows for hydroelectric power generation;

(23) "**Thermal Installation**" shall mean those facilities satisfying the criteria set forth in Section 3.2.B(5); and

(24) "**Treaty Storage Regulation**" shall mean the hydro regulation study that includes the Detailed Operating Plan operating criteria adopted prior to the beginning of the operating year and uses actual and forecast stream flows and volume runoff forecasts, unless otherwise agreed.

1.5 TREATY ORGANIZATION

Implementation of the Columbia River Treaty is carried out by the U.S. and Canadian Entities, which were appointed by the two Governments for this purpose. In accordance with the minutes of a meeting of the Privy Council approved on 4 September 1964, the Canadian Entity, except for disposals of Canadian Entitlement, is the British Columbia Hydro and Power Authority ("BC Hydro"). For disposals of the Canadian Entitlement, the Canadian Entity is the government of the Province of British Columbia (the "Provincial Government"). The Chair of BC Hydro is also designated as the Chair of the Canadian Entity by the BC Hydro Board of Directors. By Presidential executive order the U.S. Entity is composed of the Administrator of the Bonneville Power Administration and the Division Engineer of the Northwestern Division, U.S. Army Corps of Engineers. The Administrator is designated as Chairman of the U.S. Entity.

The Treaty, in Article XV, also established a Permanent Engineering Board to perform specific duties for the governments including making reports to Canada and the U.S. at least once a year on the results being achieved under the Treaty. The Permanent Engineering Board has established an Engineering Committee to assist it in its work.

The U.S. Entity has appointed a Secretary and two Coordinators, one from the Corps of Engineers and one from the Bonneville Power Administration, to coordinate the activities of the U.S. Entity. The Canadian Entity has appointed a Secretary and a Coordinator, both from BC Hydro, to coordinate the activities of the Canadian Entity. The Provincial Government has also identified a designated contact for purposes of carrying out its Entity responsibilities in respect of Article XIV(2)(i) of the Treaty (disposals of Entitlement within the U.S.)

The Entities have, in turn, established two committees: the Columbia River Treaty Operating Committee and the Columbia River Treaty Hydrometeorological Committee. Each committee has a U.S. Section and a Canadian Section with an equal number of members. The U.S. Sections of these committees have equal representation by the Corps of Engineers and the Bonneville Power Administration. The chair of the U.S. Section of the Operating Committee rotates between the Corps of Engineers and the Bonneville Power Administration. From 1 March through 31 August a representative of the Corps of Engineers is chair. From 1 September through the end of February, a representative of the Bonneville Power Administration is chair. Chart 1 outlines the Treaty organization.

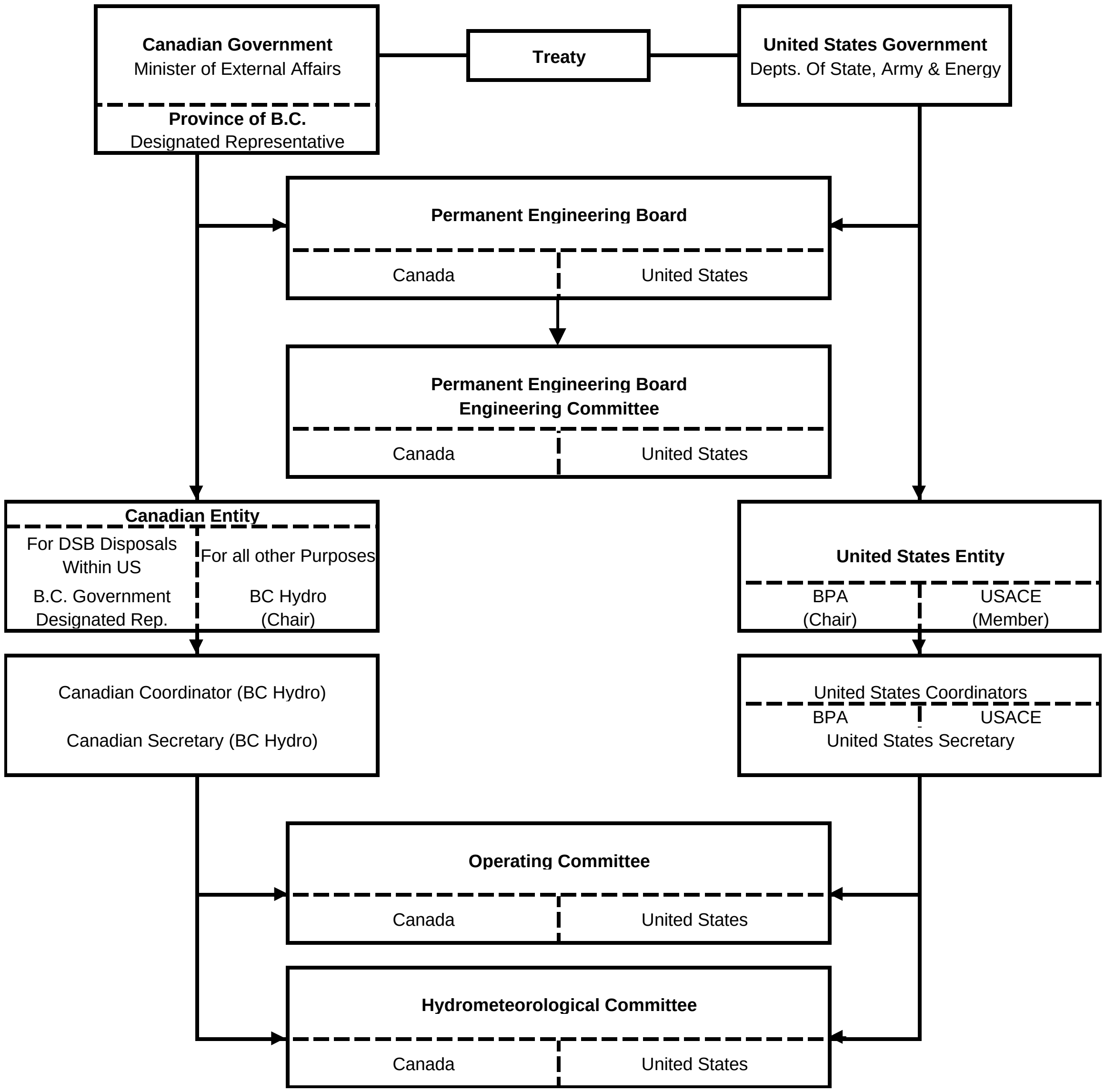
The Operating Committee membership is limited to four members from each country. This Committee is responsible for: ensuring that the system regulation studies are completed; preparing and implementing the operating plans required by the Treaty; determining Downstream Power Benefits; and carrying out other duties as required by the Entities.

The Hydrometeorological Committee membership is limited to two members from each country. This Committee is responsible for: establishing and maintaining a hydrometeorological system as required by Annex A; developing stream flow forecasting procedures and preparing forecast information throughout the operating year; and carrying out other duties as required by the Entities. Each Entity shall give evidence of appointment of Treaty representatives by written notice to the other Entity, and by similar notice either Entity may at any time change its Treaty representatives.

Delegations of authority by the Entities to their subordinate committees or representatives may take place under an Entity Agreement (if both Entities are delegating the same authority to their respective representatives) or Entity-agency agreement (if one Entity elects to delegate a specific function to a specific organization).

Chart 1

Columbia River Treaty Organization



1.6 THE POWER AND RESERVOIR SYSTEM

The operation of the Canadian Treaty Storage at Mica, Arrow, and Duncan reservoirs, in accordance with Annex A, paragraph 7, is designed to increase power generation at site and downstream in Canada and in the U.S. While the hydroelectric operating plans are designed for a specific operation at each Canadian reservoir, the obligation of Canada to provide storage regulation is measured by the composite storage in all three reservoirs in accordance with Protocol VII(2).

For development of Treaty studies, the U.S. system consists of all the hydroelectric projects on the main stem of the Columbia River, including large-capacity multipurpose storage reservoirs and run-of-the-river projects with storage capacity sufficient for weekly load factoring only. In addition, the system includes numerous reservoirs of both types on tributary streams of the Columbia River and coastal streams in the States of Washington, Oregon, Montana and Idaho.

Beginning in the 1980's, the actual operation of many U.S. projects had changed to meet increasing fish and recreational requirements. Although actual operations were somewhat modified at U.S. projects, studies developed under the Treaty continued to optimize power operations for U.S. projects. In 1996, the Entities formally agreed (see reference at 1.3(5)(c)) that for all hydroelectric operating plans developed under the Treaty the non-power requirements for Base System projects would be set to specific requirements and only changed by mutual agreement. As a result, the operating strategy shown for many projects included in hydro regulation studies carried out under the Treaty may be considerably different than actual operations implemented at those projects.

In Canada, the system included in the hydroelectric operating plans consists of Mica, Arrow Duncan, power generation at and downstream of those sites, and any other power generation coordinated therewith (see Protocol VII paragraph (3)).

Libby project, which is located in the U.S., and whose reservoir extends into Canada is operated to meet multi-purpose needs, including the obligations under Biological Opinions in the U.S. The Biological Opinions are documents prepared by U.S. federal agencies that recommend actions for the U.S. for continued existence of endangered or threatened species. The processes to coordinate the planning and operation of Libby are defined in the Treaty and the Libby Coordination Agreement.

Canadian Treaty storage projects operate in accordance with hydroelectric operating plans developed under the Treaty. Generally, Canadian Treaty projects attain their maximum pool elevations in July or August from stream flow runoff caused primarily by snow melt. Stream flows gradually fall after the summer snow melt is complete. These reservoirs are lowered by withdrawals required to augment winter stream flows to sustain the region's winter electric power demand, which is at a maximum during this period. Additional storage withdrawals may be made for the purpose of controlling floods, should the potential runoff be great enough. Regulation of the reservoirs during the spring season is for power or flood control, or both purposes coincidentally.

The Western U.S. and Canadian transmission systems integrate the entire hydroelectric system with the thermal installations required to serve the load in the region.

Project rule curves are developed for all storage projects for studies under the Treaty (see Section 2.3). These operating guidelines are incorporated into the Assured Operating Plans and Detailed Operating Plans, and their development is described in detail in Sections II, III and IV of this document. For Canadian Treaty Storage, these operating guidelines are also used for guiding storage use during the course of actual operations.

1.7 RELEASE OF INFORMATION

Requests for Treaty data or information shall be referred to the Committee Section of the requestor's country of origin; the Canadian Section will respond to Canadian requestors, and the U.S. Section will respond to U.S. requestors. In general, historical information should be shared, but forecasts, projections not incorporated in adopted documents such as the Assured Operating Plan and/or Detailed Operating Plan, or information considered sensitive by either Section should not be shared unless required by law.

2 OPERATING GUIDELINES & RULES USED IN SYSTEM REGULATION STUDIES

2.1 OVERVIEW OF SYSTEM REGULATION STUDIES

Preparation of Columbia River Treaty system regulation studies is governed by operating rules and criteria that utilize a number of “rule curves” to describe project operating strategies, subject to agreed non-power requirements. This type of project planning and development strategy is documented in the 1964 Pacific Northwest Coordination Agreement. In accordance with the 1988 Entity Agreement (see reference at Section 1.3(5)(a) and (b)), this method, to develop hydroelectric operating plans for the operation of Canadian Treaty Storage developed under the Treaty, is applied along with other operating criteria to the extent it is consistent with the Treaty.

Rule curves delineate a schedule of reservoir drafts and fills which, together with other criteria, are designed to utilize the storage and natural flow in such a manner as to produce the optimum amount of firm energy load carrying capability, usable secondary energy and reservoir refill probability under any pattern of stream flow. Secondary energy is hydro generation in excess of hydroelectric firm energy load carrying capability. The rule curves also provide guidance to assure adequate flood control on the Columbia River and its tributaries and insures a high probability that refill of the system reservoirs has priority over generation of secondary energy.

In addition to the rule curves discussed above, operating rules, project operating criteria, and agreed non-power requirements (collectively referred to as “system operating criteria”) also guide the use of system storage in the Treaty system regulation studies. The system operating criteria are derived from system-wide power regulation studies and previous operating experience, as well as hydrologic analyses of flood control problems in the basin. Both power regulation studies and flood control analyses are usually developed in part by simulation techniques using mathematical models.

The system operating criteria developed by the simulations are intended for use in guiding the actual operation of Canadian Treaty Storage. They prescribe a coordinated use of storage so that optimum power generation in the combined systems will be achieved in accordance with the provisions of Annex A, paragraphs 7 and 8 of the Treaty, whichever apply.

Non-power requirements applicable to Treaty studies have been established by agreement (see reference at Section 1.3(5)(c)) and may only be changed by subsequent agreement between the Entities (which may occur as part of the development of the hydroelectric operating plans). However, each project owner is also subject to non-power requirements which may differ from the established operating procedures for Treaty studies. The Treaty, in Article III, requires the studies used to determine Downstream Power Benefits to reflect an operation of the Base System and main stem projects which makes the most effective use of the improvement in stream flow resulting from Canadian Treaty Storage operation. Because of this, actual U.S. project operation may be quite different than the corresponding U.S. project operation included in the Treaty studies.

2.2 SYSTEM REGULATION STUDIES

The Treaty requires an Assured Operating Plan be developed each year for the sixth succeeding year of operation. It also permits the development of additional detailed operating plans at any time (typically one is developed prior to the start of each operating year). Each operating plan specifies the rule curves, operating rules, project operating criteria and agreed non-power requirements applicable to operation for that plan. These system operating criteria are developed from a series of system regulation studies designed specifically to develop and test the criteria, as described in Sections 2.2.A, 2.2.B and 2.2.C below.

In accordance with Protocol VIII, all system regulation studies carried out under the Treaty encompass the thirty year record of stream flows from August 1928 through July 1958, with updates for current best estimates of irrigation depletions and return flows, and corrections for errors and omitted projects.

2.2.A CRITICAL PERIOD SYSTEM REGULATION STUDIES

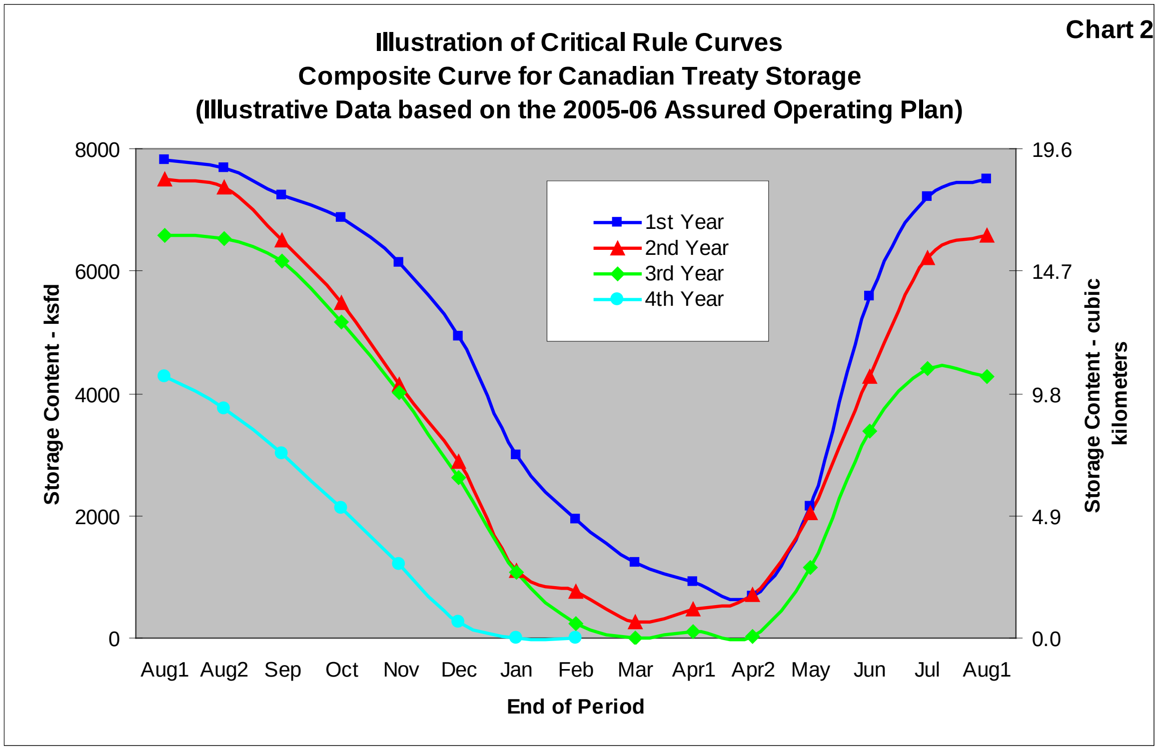
The "Critical Period System Regulation Study" is an optimal operation of the reservoir system to determine the critical period, the firm energy load carrying capability of the system and the Critical Rule Curves (see Section 2.3.A below). The critical period is defined as "the period, beginning with the initial release of stored water from full reservoir conditions and ending with the reservoirs empty, when the water available from reservoir releases plus the natural stream flow is capable of producing the least amount of hydroelectric power in meeting system load requirements" (see Section 1.4). Critical Period System Regulation Studies optimally utilize available storage to shape system generation similar to firm load during the most adverse flow sequence of the historical period of stream flows. The system generation during the critical period is the firm energy load carrying capability.

The critical period can be of varying length depending on the number and size of storage reservoirs in the system, the in-service schedule of new resources, the maintenance schedule for thermal resources and the shape of the system load. The Entities do not agree on whether or not the length of the critical period may be affected by non-power requirements other than flood control. However, this dispute was resolved for the foreseeable future by the 1996 Entity Agreement (see Section 1.3(5)(c)) through the adoption of agreed non-power requirements for Canadian and Base System projects.

The Critical Period System Regulation Study shall assume:

- Each reservoir shall be at its normal Upper Rule Curve elevation, or filled to the extent feasible, at the beginning of the critical period, and shall be drafted to its normal minimum elevation, or to the extent feasible, by the end of the critical period;
- The system shall be regulated with the intent to maximize critical period energy, shaped to the load of the Pacific Northwest Area, within the operating constraints applied to the study;
- The optimization technique shall assume complete foreknowledge of all stream flows during the critical period;
- When agreed non-power requirements (see Section 2.5) limit release of water in the critical period, the regulation shall be based on the maximum storage use consistent with the limitations;
- The generation at any storage project shall not exceed an 85 percent plant factor in any month except for non-power requirements, unless a higher plant factor is necessary to make all storage water usable during the critical period; and

- In multiple-year critical periods, no reservoir shall be drafted by 31 March below the elevations determined by its Assured Refill Curve (see Section 2.3.B(1) below), unless all reservoirs have been drafted to such elevations and additional draft is required to meet the firm energy load carrying capability of the system. (Since the Assured Refill Curve cannot be calculated until the firm energy load carrying capability is known, the Critical Period System Regulation Study generally uses an estimate of this curve.)



2.2.B REFILL STUDIES

These studies encompass the 30-year historical record of stream flows and are used to develop the Assured and Variable Refill Curves (see Section 2.3.B below). The studies incorporate the Critical Rule Curves (see Section 2.3.A) and firm energy load carrying capability developed in the Critical Period System Regulation Study. Each historical water year is assumed to start full or at the maximum elevation permitted by non-power requirements. If, in more than 5 percent of the years in the historical period (2 of 30), the storage energy in the reservoirs fails to refill to 98 percent of the total system storage energy on July 31st and secondary energy was produced in the January through July period, the system does not pass the refill test. Failure of any reservoir to refill, when secondary energy is produced by the system during January through July, and when all major projects are limited by maximum storage or minimum outflows during periods with secondary generation, shall be considered a conditional pass. Failure of the system to operate in accordance with this refill principle shall require that the Refill Curves described in Section 2.3.B be modified to eliminate such failures.

2.2.C 30-YEAR SYSTEM REGULATION STUDIES

"30-Year System Regulation Studies" encompassing the 30-year historical record of stream flows (from 1928-29 through 1957-58) are used to test the system operating criteria over a wide range of potential future inflows. These studies cycle through each of the historic stream flow conditions sequentially, which is intended to simulate the full range of stream flow scenarios that is likely to be encountered in operations. The Protocol, paragraph VIII, restricts the Entities to the use of 30-years of record until 2003, and thereafter, unless otherwise agreed.

These studies are used to determine the average annual usable energy and dependable peaking capacity produced by the Canadian and U.S. systems. The studies incorporate firm loads equal to the firm energy load carrying capability of the U.S. system as determined by the Critical Period System Regulation Study and the system operating criteria developed for the operating plan.

2.3 RULE CURVES

2.3.A CRITICAL RULE CURVES

A Critical Rule Curve provides a monthly guide to reservoir storage drafts and fills so as to provide an optimum power operation to meet system firm energy load carrying capability during periods of low inflows (see Chart 2). The end-of-month storage contents attained by the storage reservoirs in the Critical Period System Regulation Study form the Critical Rule Curves for each project. In multiple-year critical periods there will be a Critical Rule Curve for each corresponding year of the critical period. Not withstanding the time sequence, the first curve is the one highest in indicated system storage energy for the coordinated system on 31 July, the second is the next highest, etc. For Refill Studies, 30-Year System Regulation Studies and actual operations, the second curve will be limited to no higher than the first, the third no higher than the second, etc. for each project and for each month.

2.3.B REFILL CURVES

A Refill Curve is a guide to operation of a reservoir which optimizes the production of usable energy consistent with an agreed probability that reservoir refill will not be jeopardized by secondary energy production. A reservoir shall not be drafted below its Refill Curve to serve any secondary energy loads, unless required by established operating procedures at the project.

Two Refill Curves are developed to guide reservoir operations. One of the curves, the Variable Refill Curve described in Section 2.3.B(2), is based on a conservative estimate of the expected inflows for the current water year. The second curve, the Assured Refill Curve described in Section 2.3.B(1), is developed using the second lowest inflow in the period of historic stream flows. In essence, the Assured Refill Curve is designed to ensure that the operation is no more conservative than that required to refill under the second lowest historical inflow sequence. Assured Refill Curves are developed for all reservoirs. Variable Refill Curves are only developed for cyclic reservoirs – i.e. those reservoirs where the greater of the Assured Refill Curve and the first year Critical Rule Curve is not empty in March[1].

[1] Reservoirs where the greater of the Assured Refill Curve and the first year Critical Rule Curve is empty in March are generally referred to as "annual" reservoirs. These reservoirs will typically operate from normal maximum to normal minimum and back to normal maximum on an annual cycle. Cyclic reservoirs typically will be drafted to normal minimum over an extended period of dry years.

(1) **ASSURED REFILL CURVE:** The Assured Refill Curve indicates the end-of-month storage content required to assure refill of the reservoir based on 1931 historical volume of inflow during the refill period. The year 1931 represents the second lowest historical January through July volume inflow for the Columbia River for the period 1928 to 1958 measured near The Dalles, Oregon. The second lowest water year is used because it is equivalent to a 95% confidence level, based on a thirty-year period of stream flows.

In computing the Assured Refill Curve for a project at the end of any month, the net volume of water available for refill of a reservoir is computed from the actual 1931 historical inflow volume from the end of that month through July 1931and is reduced by:

- the Power Discharge Requirement from the end of the month through July. The Power Discharge Requirement is determined as described in subsection (3) below and shall be not less than the project minimum discharge requirement;
- consumptive requirements for water at-site and upstream from the end of the month through July; and
- water required for refill of upstream reservoirs, which is the difference between full and the greater of the first-year Critical Rule Curve and the Assured Refill Curve at each of the upstream reservoirs.

The Assured Refill Curves will be initialized at levels that optimally meet firm energy load carrying capability during the refill period and that satisfy the refill test when Variable Refill Curves are not implemented. If necessary, the Assured Refill Curve shall be adjusted to prevent the system from failing the refill test described in subsection (3), below. Detailed procedures for determining Assured Refill Curves are provided in Appendix 1.

(2) **VARIABLE REFILL CURVE**: The Variable Refill Curve indicates the end-of-month storage content required during the January through July period to refill each cyclic reservoir consistent with refill criteria, at-site volume inflow forecasts, upstream reservoir refill requirements and power discharge requirements.

In Refill Studies and 30-Year System Regulation Studies, Variable Refill Curves are generally developed from the historical inflow volumes applicable to each water year, using the procedures described below and illustrated in Table 2A. The procedures are designed to mimic the calculations in actual operations. However, there is no agreed stream flow forecast information for the period of historic stream flows used in the studies. Therefore, the actual historical inflow volume from the start of the month to the end of July is used as a proxy for the stream flow forecast applicable to that month and that water year. The Variable Refill Curve is determined for each month during the period from January through July by deducting the net volume of water available for refill of the reservoir from the full content of that reservoir. In computing the net volume of water available for refill of a reservoir from the end of the month, the proxy run-off forecast volume shall be reduced by:

- the appropriate run-off volume forecast error such that there is a 95 percent probability that the reduced forecast volume will be equaled or exceeded (to simulate the average reduction that would be applied in actual operations);
- the Power Discharge Requirement from the end of the month through July. The Power Discharge Requirement is determined as described in subsection (3) below and shall be not less than the project minimum discharge requirement;
- consumptive requirements for water at-site and upstream from the end of the month through July; and

- water required for refill of upstream reservoirs, which is the difference between full and the Operating Rule Curve for each of the upstream reservoirs.

Using the net volumes of inflow determined above, Variable Refill Curves shall be determined for each of the periods from January through to the end of the refill period, giving the month-end storage content required to provide a high probability of refilling the reservoir.

The Variable Refill Curve developed using the above procedure may allow storage drafts in excess of the amount of storage draft that results in an optimal power operation. Therefore to ensure optimal power operation in the studies as required by Treaty Article III(2), beginning with the Assured Operating Plan for 2005-06, the Entities have agreed to limit the Variable Refill Curve to be no lower than a Variable Refill Lower Limit Curve, which is defined by studies that optimize power production during the refill period. The Variable Refill Lower Limit Curves are a function of the unregulated January through July run-off volume at The Dalles, Oregon. Detailed procedures for development of these limits are provided in Appendix 1.

For use in the Treaty Storage Regulation study (see Section 4.4.A), Variable Refill Curves are computed using the same procedure as described above, but incorporate run-off volume forecasts, not historic flows. The Variable Refill Curve is updated monthly, except during 15 April through 30 April, as illustrated in Table 2B.

(3) **Power Discharge Requirement:** The Power Discharge Requirement is simply a parameter used to develop the Refill Curves described above. Initially the Power Discharge Requirements are generally set to project minimum discharges. The Assured and Variable Refill Curves determined in subsections (1) and (2) above are tested in a Refill Study as described in Section 2.2.B. If the system fails to operate in accordance with the refill principles, the net volumes available for refill determined in (1) and (2) above are reduced by increasing the Power Discharge Requirements at projects that failed to refill by 31 July and the Assured and Variable Refill Curves are then re-computed and the procedure is repeated until the system meets this test, or until no further improvement in either the probability of refill or the volume of refill can be made.

When the system either passes the refill test or no further improvements are possible (a “conditional pass”), the resulting Assured and Variable Refill Curves will be used in the 30-Year System Regulation Studies and the Power Discharge Requirements developed in these Refill Studies shall be used in the computation of Variable Refill Curves for the Treaty Storage Regulation study (see Section 4.4.A) based on forecast volume inflow.

Table 2A

VRC Computation During AOP and DOP Planning Studies

Power Discharge Requirements from AOP 2001-02

Volume Runoff at The Dalles		Mica 01-Jan	Mica 01-Feb	Mica 01-Mar	Mica 01-Apr	Mica 16-Apr	Mica 01-May	Mica 01-Jun	Mica 01-Jul	Arrow 01-Jan	Arrow 01-Feb	Arrow 01-Mar	Arrow 01-Apr	Arrow 16-Apr	Arrow 01-May	Arrow 01-Jun	Arrow 01-Jul
Up to 80 MAF **[Use this for 1929 WY]**	cfs	**3,000**	**10,000**	**10,000**	**10,000**	**12,000**	**20,000**	**20,000**	**20,000**	**5,000**	**18,000**	**20,000**	**20,000**	**22,000**	**30,000**	**42,000**	**44,000**
Between 80 and 95 MAF		Linear Interpolation								Linear Interpolation							
95 MAF	cfs	3,000	3,000	3,000	8,000	10,000	12,000	15,000	18,000	5,000	5,000	5,000	8,000	20,000	27,000	37,000	37,000
Between 95 and 110 MAF		Linear Interpolation								Linear Interpolation							
110 MAF and above	cfs	3,000	3,000	3,000	8,000	10,000	12,000	15,000	18,000	5,000	5,000	5,000	8,000	20,000	27,000	37,000	37,000

Variable Refill Curve Computation [Example presents 1929 WY; 1980 Depletion Level]

		Mica 01-Jan	Mica 01-Feb	Mica 01-Mar	Mica 01-Apr	Mica 16-Apr	Mica 01-May	Mica 01-Jun	Mica 01-Jul	Arrow 01-Jan	Arrow 01-Feb	Arrow 01-Mar	Arrow 01-Apr	Arrow 16-Apr	Arrow 01-May	Arrow 01-Jun	Arrow 01-Jul
1929 Flows [1980 Modified Streamflow]	cfs	3786	3195	3144	2195	3727	17847	57916	45060	6609.1	4998.9	6777.3	7982	14347	48998.1	111293.5	78080
1929 Flow Volume	ksfd	117	89	97	33	56	553	1737	1397	205	140	210	120	215	1519	3339	2420
"Probable Inflow": Date to 31 July	ksfd	4081	3963	3874	3776	3744	3688	3134	1397	8168	7963	7823	7613	7493	7278	5759	2420
95% Forecast Error	ksfd	683	551	513	460	451	441	471	0	1,359	1,042	940	790	766	742	853	0
95% Conf Inflow: Date to 31 July	ksfd	3,398	3,412	3,360	3,316	3,293	3,247	2,664	1,397	6,809	6,921	6,883	6,823	6,727	6,536	4,906	2,420
Remaining Inflow Period to 31 July		1Feb-31Jul	1Mar-31Jul	1Apr-31Jul	16Apr-31Jul	1May-31Jul	1Jun-31Jul	1Jul-31Jul		1Feb-31Jul	1Mar-31Jul	1Apr-31Jul	16Apr-31Jul	1May-31Jul	1Jun-31Jul	1Jul-31Jul	
Disagg Ratios: Month end to 31 July		2.5%	2.3%	2.5%	1.9%	5.2%	19.8%	50.5%	100%	2.8%	2.8%	2.9%	2.5%	7.1%	24.0%	54.6%	100%
% Inflow Remaining: Month end to 31 July	%	97.5%	97.7%	97.5%	98.1%	94.8%	80.2%	49.5%		97.2%	97.2%	97.1%	97.5%	92.9%	76.0%	45.4%	
95% Conf Inflow: Month end to 31 July	ksfd	3,312	3,334	3,276	3,252	3,122	2,604	1,319		6,618	6,727	6,683	6,652	6,250	4,967	2,227	
Days in Period	Days	31	28	31	15	15	31	30	31	31	28	31	15	15	31	30	31
Monthly Min Release [**1929 WY < 80 MAF**]	ksfd	93	280	310	150	180	620	600	620	155	504	620	300	330	930	1260	1364
Cum Min Release: Monthend to 31 July	ksfd	2760	2480	2170	2020	1840	1220	620	0	5308	4804	4184	3884	3554	2624	1364	0
Upstream Operating Rule Curve	ksfd	0	0	0	0	0	0	0	0	2,586	2,099	1,579	1,349	1,127	1,315	2,460	3,529
Upstream refill: Month end to 31 July	ksfd	0	0	0	0	0	0	0	0	942.6	1430	1950.2	2180	2401.8	2213.9	1068.6	0
End of Month Variable Refill Curve	ksfd	**2,977**	**2,675**	**2,423**	**2,297**	**2,247**	**2,145**	**2,830**	**3,529**	**3,212**	**3,087**	**3,031**	**2,992**	**3,286**	**3,451**	**3,580**	**3,580**

Computation of Mica Operating Rule Curve (ORC) for Arrow Variable Refill Curve Calculations

		01-Jan	01-Feb	01-Mar	01-Apr	16-Apr	01-May	01-Jun	01-Jul
1st Year Critical Rule Curve (CRC)		1779.8	1221.4	1225.8	523.5	204.3	664.5	2312	3374.7
Variable Refill Curve (VRC)		2,978	2,676	2,423	2,297	2,248	2,146	2,831	3,529
Assured Refill Curve (ARC)		2586.4	2099	1578.8	1349	1127.2	1315.1	2460.4	3529.2
Operating Rule Curve Lower Limit (ORCLL)		651.6	399.3	0	0				
Upper Rule Curve (URC)		3385.7	3347.2	3304.6	3304.6	3304.6	3369.1	3447.9	3529.2
Higher of ARC or CRC		2586.4	2099	1578.8	1349	1127.2	1315.1	2460.4	3529.2
Lower of line above and VRC		2,586	2,099	1,579	1,349	1,127	1,315	2,460	3,529
Lower of line above and URC		2,586	2,099	1,579	1,349	1,127	1,315	2,460	3,529
ORC = Higher of line above and ORCLL		**2,586**	**2,099**	**1,579**	**1,349**	**1,127**	**1,315**	**2,460**	**3,529**

Table 2B

Variable Refill Curve Computation During Operating Year [Example presents 2002 Water Year]

		Mica							Arrow						
Monthly Forecasts		01-Jan	01-Feb	01-Mar	01-Apr	01-May	01-Jun	01-Jul	01-Jan	01-Feb	01-Mar	01-Apr	01-May	01-Jun	01-Jul
Probable Total Project Inflow to 31 July	ksfd	4,443	4,345	4,180	4,184	3,983	3,183		9,784	9,601	9,254	8,989	8,457	6,341	
95% Forecast Error	ksfd	653	510	465	445	361	361		1,233	987	825	716	502	502	
95% Conf Inflow to 31 July	ksfd	3,790	3,835	3,715	3,739	3,622	2,822		8,551	8,614	8,429	8,273	7,955	5,839	
Dalles Volume Forecast (Jan - Jul)	MAF	86.9	88.0	86.2	87.8	89.7	91.6		86.9	88.0	86.2	87.8	89.7	91.6	
		14.7%	11.7%	11.1%	10.6%	9.1%	11.3%								
January Computation															
% Inflow Remaining: Month end to 31 July [1961-94 Ave]	%	100.0%	97.6%	95.1%	90.0%	71.6%	35.5%		100.0%	97.5%	94.4%	87.5%	65.5%	30.3%	
95% Conf Inflow: Month end to 31 July	ksfd	3,790	3,699	3,604	3,411	2,714	1,345		8,551	8,337	8,072	7,482	5,601	2,591	
Min Outflow: Month end to 31 July [PDR for Dalles forecast]	ksfd	1,827	1,743	1,650	1,380	1,008	558		3,809	3,669	3,514	3,094	2,257	1,147	
U/S Discharge Requirement [From ORC]: Monthend to 31 July	ksfd	0	0	0	0	0	0		1,963	1,956	2,057	2,402	2,214	1,069	
End of Month VRC [Full - 95% Inflow + PDR + U/S Refill]	ksfd	1,566	1,573	1,575	1,498	1,824	2,742		801	868	1,079	1,594	2,450	3,205	
		Jan VRC			Forecast VRCs				Jan VRC			Forecast VRCs			
February Computation															
% Inflow Remaining: Month end to 31 July	%		97.6%	95.1%	90.0%	71.6%	35.5%			97.5%	94.4%	87.5%	65.5%	30.3%	
95% Conf Inflow: Month end to 31 July	ksfd		3,743	3,647	3,452	2,746	1,361			8,399	8,132	7,537	5,642	2,610	
Min Outflow: Month end to 31 July	ksfd		1,743	1,650	1,380	1,008	558			3,669	3,514	3,094	2,257	1,147	
Upstream Refill: Month end to 31 July	ksfd		0	0	0	0	0			2,000	2,057	2,402	2,214	1,069	
End of Month Variable Refill Curve	ksfd		1,529	1,532	1,458	1,791	2,726			850	1,019	1,539	2,409	3,186	
			Feb VRC		Forecast VRCs					Feb VRC		Forecast VRCs			
March Computation															
% Inflow Remaining: Month end to 31 July	%			97.4%	92.2%	73.3%	36.3%				96.9%	89.8%	67.2%	31.1%	
95% Conf Inflow: Month end to 31 July	ksfd			3,618	3,425	2,723	1,349				8,168	7,569	5,664	2,621	
Min Outflow: Month end to 31 July	ksfd			1,650	1,380	1,008	558				3,514	3,094	2,257	1,147	
Upstream Refill: Month end to 31 July	ksfd			0	0	0	0				2,057	2,402	2,214	1,069	
End of Month Variable Refill Curve	ksfd			1,561	1,484	1,814	2,739				983	1,507	2,387	3,175	
				Mar VRC		Forecast VRCs					Mar VRC		Forecast VRCs		
April Computation															
% Inflow Remaining: Month end to 31 July	%				94.7%	75.3%	37.3%					92.6%	69.3%	32.1%	
95% Conf Inflow: Month end to 31 July	ksfd				3,541	2,815	1,395					7,661	5,733	2,656	
Min Outflow: Month end to 31 July	ksfd				1,380	1,008	558					3,094	2,257	1,147	
Upstream Refill: Month end to 31 July	ksfd				0	0	0					2,402	2,214	1,069	
End of Month Variable Refill Curve	ksfd				1,368	1,722	2,693					1,415	2,318	3,140	
					Apr VRC	Forecast VRCs						Apr VRC	Forecast VRCs		
May Computation															
% Inflow Remaining: Month end to 31 July	%					79.5%	39.4%						74.9%	34.7%	
95% Conf Inflow: Month end to 31 July	ksfd					2,879	1,427						5,958	2,760	
Min Outflow: Month end to 31 July	ksfd					1,008	558						2,257	1,147	
Upstream Refill: Month end to 31 July	ksfd					0	0						2,214	1,069	
End of Month Variable Refill Curve	ksfd					1,658	2,660						2,093	3,036	
						May VRC	Forecast VRC						May VRC	Forecast VRC	
June Computation															
% Inflow Remaining: Month end to 31 July	%						49.5%							46.3%	
95% Conf Inflow: Month end to 31 July	ksfd						1,397							2,703	
Min Outflow: Month end to 31 July	ksfd						558							1,147	
Upstream Refill: Month end to 31 July	ksfd						0							1,069	
End of Month Variable Refill Curve	ksfd						2,690	3,529						3,093	3,580
							Jun VRC	Jul VRC						Jun VRC	Jul VRC

2.3.C OPERATING RULE CURVE LOWER LIMIT

The Operating Rule Curve Lower Limit (formerly referred to as Limiting Rule Curves) consists of the minimum month-end storage contents which provide a high probability that the system will be capable of meeting its firm energy load carrying capability during the period 1 January through 30 April in the event that the Variable Refill Curves permit storage to be emptied and sufficient natural flow is not available prior to the start of the freshet. The Operating Rule Curve Lower Limit shall not be higher than the Upper Rule Curve at each project. The Operating Rule Curve Lower Limit is developed from 1936-37 water conditions which represents the lowest January through 30 April run-off volume for the system as a whole during the 30-year period of record. For multi-year critical periods, the Operating Rule Curve Lower Limits are determined from special 1937 hydro regulation studies. In these studies, uniform load is added in each period from August through December until the system drafts empty, usually by the end of April. If the critical period is one year or less, the Operating Rule Curve Lower Limit and the first year Critical Rule Curve are identical during the period 1 January through 30 April.

2.3.D UPPER RULE CURVES

Upper Rule Curves define the maximum storage content of each reservoir. These curves are determined from flood control regulations, in accordance with the concepts of the Flood Control Operating Plan. Storage above the Upper Rule Curve is permitted only when necessary to meet the objectives of the Flood Control Operation Plan. The Upper Rule Curves shall consist of the following:

(1) During the Flood Control Storage Evacuation Period the Upper Rule Curve shall be derived from Flood Control Storage Reservation Diagrams. Required draft for headwater projects are based on at-site inflow forecasts. Evacuation of major lakes controlled by dams is designed to achieve the maximum natural storage effect of the lakes during the refill period. Required draft for certain projects, including Grand Coulee, Mica, and Arrow, are based on the unregulated runoff forecasts for the Columbia River at The Dalles, Oregon, for the period April through August.

(2) During the refill period the Upper Rule Curve shall be the maximum storage content necessary to control the flood runoff to non-damaging levels if possible, and to regulate larger floods that cannot be controlled to non-damaging levels to the lowest possible level with the available storage space. This regulation is accomplished by establishing a flood control objective at The Dalles and adjusting outflows from Arrow, Grand Coulee, and John Day projects to meet the controlled flow. The initial objective, the "Initial Controlled Flow for the Columbia River at The Dalles", is determined as described in the Flood Control Operating Plan. Adjustments to the controlled flow objective can be made, if necessary, as the refill period proceeds. During this period the headwater project outflows are normally reduced to their minimums unless greater flows are needed for other purposes and the higher flows are not detrimental to flood control objectives. Higher outflows may also be maintained if required to control storage space during exceedingly large floods.

(3) During both the evacuation and refill periods, the Upper Rule Curve may be modified by project construction or other contingency requirements.

2.3.E OPERATING RULE CURVES

The Operating Rule Curve for each reservoir is a synthesis of all of the preceding curves. It is developed from the first Critical Rule Curve, Assured Refill Curve, Variable Refill Curve, Operating Rule Curve Lower Limit and the Upper Rule Curve as follows (see also Charts 3 and 4):

- During the period 1 August through 31 December, the Operating Rule Curve shall be defined by the higher of the first Critical Rule Curve and the Assured Refill Curve but no higher than the Upper Rule Curve;
- During the period 1 January through 15 April, the Operating Rule Curve shall be defined by the higher of the first Critical Rule Curve and the Assured Refill Curve, unless the Variable Refill Curve is lower - then it controls, but no lower than the Operating Rule Curve Lower Limit and no higher than the Upper Rule Curve; and
- During the period 16 April through 31 July, the Operating Rule Curve shall be defined by the higher of the first Critical Rule Curve and the Assured Refill Curve, unless the Variable Refill Curve is lower - then it controls, but no higher than the Upper Rule Curve.

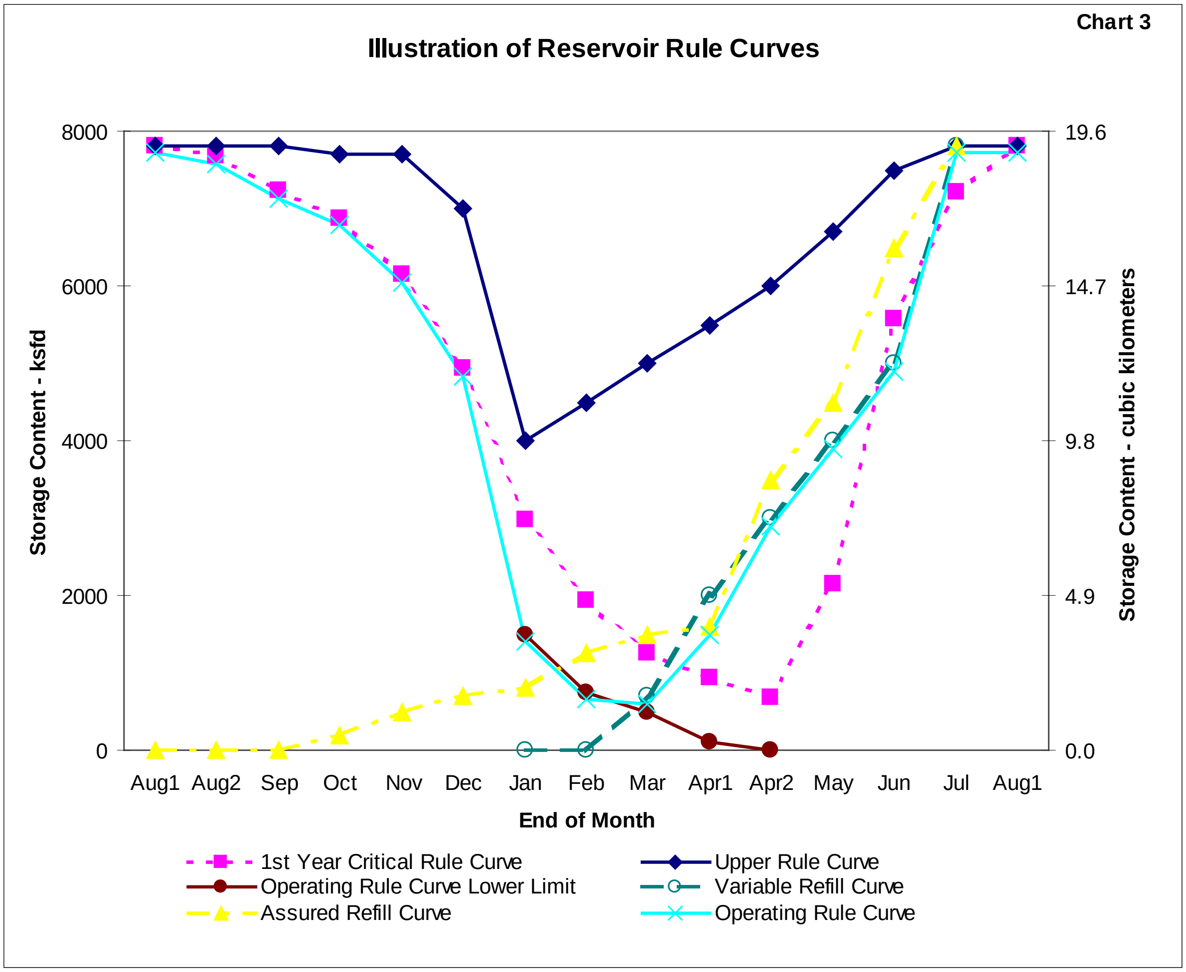
2.4 OPERATING RULES

Operating Rules describe how the rule curves and other operating criteria are used to coordinate storage drafts and fills amongst the reservoirs. Such rules, as outlined below, are designed to achieve an operation of the system, including Canadian Treaty Storage, for optimum generation in accordance with Annex A, paragraph 7 or 8 of the Treaty, whichever applies. These Operating Rules shall be observed in conducting the System Regulation Studies and in actual operation of Canadian Treaty Storage.

2.4.A COMPOSITE OPERATION OF CANADIAN TREATY STORAGE

While the procedures described above develop a specific operating plan for each Canadian reservoir, Protocol VII(2) provides that the hydroelectric operating plans should provide a reservoir balance relationship for the whole of Canadian Treaty Storage. To accomplish this, Canadian Treaty Storage operation is guided by the composite Operating Rule Curve and composite Critical Rule Curves for the whole of Canadian Treaty Storage.

The composite Operating Rule Curve for the whole of Canadian Treaty Storage for each month is the summation of the storage corresponding to the Operating Rule Curve indicated for Mica, Arrow and Duncan for that month. Similarly, the composite Critical Rule Curve for the whole of Canadian Treaty Storage for each month is the summation of the storage corresponding to the Critical Rule Curves indicated for Mica, Arrow and Duncan for that month. In actual operation, the Canadian Entity may vary the individual project operation in any manner consistent with the composite operation for Canadian Treaty Storage in the hydroelectric operating plan and the individual Upper Rule Curves at each project.



Notes for Chart 3:

The formula for determining the Operating Rule Curve is provided in Section 2.3.E and on Chart 4. Mathematically, this formula can be stated as:

ORC = Min (Max (Min (Max (ARC, CRC1), VRC), ORCLL), URC)

Where:

ORC = Operating Rule Curve;

ARC = Assured Refill Curve;

CRC1 = 1st year Critical Rule Curve;

VRC = Variable Refill Curve;

ORCLL = Operating Rule Curve Lower Limit; and

URC = Upper Rule Curve.

In application of the above formula, if the ORCLL is not defined for a period, it should be replaced with normal minimum reservoir contents and if the VRC or CRC1 is not defined for a period, it should be replaced with normal maximum reservoir contents. ARC and URC are defined for all periods.

Chart 4

Developing Operating Rule Curves for System Regulation Studies

Rule Curve	Description
Critical Rule Curve (CRC1, CRC2, CRC3, etc)	The Critical Rule Curves are developed for each reservoir by the Critical Period Regulation Study. They guide the reservoir drafts and fills to maximize the system firm energy load carrying capability. The first Critical Rule Curve is used in the development of the Operating Rule Curve. The Critical Rule Curves define proportional drafting points below the Operating Rule Curve, to guide reservoir operation while generating system firm energy load carrying capability during low water conditions.
Assured Refill Curve (ARC)	The Assured Refill Curve indicates the end of month storage content required to assure reservoir refill based on the 1931 historical volume inflow (the second lowest Jan - Jul volume inflow in the 30 year streamflow record). The resulting curve provides a check on the Variable Refill Curve, and allows a deeper draft if the Variable Refill Curve is found to be overly conservative.
Variable Refill Curve (VRC)	The Variable Refill Curve indicates the end of month storage content required to refill the reservoir based upon a 95% refill probability, the most current at-site volume inflow forecast, and upstream refill requirements. For non-operating studies (e.g. Assured Operating Plan and Detailed Operating Plan studies), the curve is developed from actual historic inflows, not forecasts. The Variable Refill Curve provides a guide to optimize production of usable energy, when such production does not jeopardize refill.
Upper Rule Curve (URC)	The Upper Rule Curve defines the minimum reservoir drawdown required to regulate floods to non-damaging levels, if possible. The amount of drawdown varies with the time of year and the runoff volume forecast.
Operating Rule Curve Lower Limit (ORCLL)	The Operating Rule Curve Lower Limit indicates the minimum month-end storage contents which must be maintained to provide a high probability of maintaining the system firm energy load carrying capability from 1 Jan to 30 Apr, in the event that the Variable Refill Curve permits storage to be emptied prior to the start of the freshet.
Operating Rule Curve (ORC)	The Operating Rule Curve is developed from the 1st Critical Rule Curve, Assured Refill Curve, Variable Refill Curve, Operating Rule Curve Lower Limit and Upper Rule Curve as follows: 1 Aug - 31 Dec: ORC = Higher of CRC1 and ARC. 1 Jan - 31 Jul: ORC = Lower of VRC and Higher of CRC1 and ARC 1 Jan - 15 Apr: ORC is limited to no lower than ORCLL At all times: ORC is limited to no higher than the URC The Operating Rule Curve allows, but limits, reservoir operation for the purpose of producing secondary energy. Reservoirs are drafted below Operating Rule Curves only if required to maintain the firm energy load carrying capability of the system.

Periods of the Year that Rule Curves Apply

	1-15 August	16-31 August	September	October	November	December	January	February	March	1-15 April	16-30 April	May	June	July
Critical Rule Curve	C	C	C	C	C	C	C	C	C	C	C	C	C	C
Assured Refill Curve	A	A	A	A	A	A	A	A	A	A	A	A	A	A
Variable Refill Curve							V	V	V	V	V	V	V	V
Upper Rule Curve	U	U	U	U	U	U	U	U	U	U	U	U	U	U
ORC Lower Limit							L	L	L	L				
Operating Rule Curve	O	O	O	O	O	O	O	O	O	O	O	O	O	O

2.4.B

OPERATION ABOVE THE OPERATING RULE CURVE

The whole of the Canadian Treaty Storage shall be drafted to its Operating Rule Curve as required to produce optimum generation. Draft to Operating Rule Curve is limited at Mica and all U.S. storage reservoirs to maximum powerhouse discharge and a maximum coordinated system generation equal to the firm energy load carrying capability plus the secondary market limit (see Section 3.2.B(7)).

2.4.C PROPORTIONAL DRAFT BELOW THE OPERATING RULE CURVE

The whole of the Canadian Treaty Storage shall be drafted below its Operating Rule Curve to the extent that a System Regulation Study determines that proportional draft below the Operating Rule Curves is required to produce the hydro firm energy load carrying capability of the U.S. system as determined by the applicable Critical Period System Regulation Study.

When proportional draft conditions above are met, the whole of the Canadian Treaty Storage and all reservoirs in the U.S. system shall be drafted proportionally between their respective Operating Rule Curves and their first Critical Rule Curves. If it is necessary to draft additional storage after system reservoirs reach their first Critical Rule Curves the proportional draft shall be made between their first and second Critical Rule Curves, their second and third Critical Rule Curves, etc. When it is necessary to operate the whole of the Canadian Treaty Storage and the U.S. reservoirs below their lowest Critical Rule Curves, they shall be operated proportionally between their lowest Critical Rule Curves and their normal minimum contents. If the storage content for any reservoir is equal to or lower than the Critical Rule Curve to which the system is being proportionally drafted, such reservoir shall not participate in proportional draft until the system proportional draft requires that it be drafted. It shall then participate in the additional system draft. Proportional draft is limited to maximum powerhouse discharge at Mica and all U.S. reservoirs, and by non-power requirements and project operating criteria.

Proportionality between rule curves shall be computed in terms of storage.

2.5 NON-POWER REQUIREMENTS

In Treaty studies, project operations[2] are subject to agreed (established) non-power requirements, which may include:

- Maximum rate of storage draft and refill;
- Maximum and minimum flows;
- Maximum ramping rates;
- Maximum and minimum reservoir elevations;
- Flood control criteria; and
- Other agreed at site non-power requirements.

The Entity Agreement cited in Section 1.3(5)(c) contains the non-power requirements for inclusion in Treaty studies. For convenience, these non-power requirements, including modifications agreed to since that document was signed, are listed in Appendix 2.

[2] Actual operations may be subject to additional non-power requirements that are not included in Treaty studies.

2.6 PROJECT OPERATING CRITERIA

In Treaty studies, some U.S. projects may be operated in accordance with specific project related criteria that may override the Operating Rules discussed in Section 2.4. This can apply to many of the smaller projects ("hydro independents") and occasionally may apply to larger projects such as Brownlee.

In addition, to ensure Canadian Treaty Storage is operated in accordance with Annex A, paragraph 7, to provide optimum generation in Canada and the U.S., the Mica project is routinely operated to its own criteria developed annually in the hydroelectric operating plans. The operating criteria for Mica project typically consist of target end-of-month storage contents or target monthly outflows, with modifications as a function of Arrow reservoir storage content, and specified maximum and minimum monthly outflows. The Mica operating criteria are designed to accomplish the following:

- Increase the firm energy, secondary energy, and/or dependable capacity of Mica and the Canadian downstream projects;
- Improve the monthly distribution of energy production on the Canadian system; and
- Maintain sufficient outflow to allow peaking during all periods.

In the event that Mica's operation pursuant to the applicable operating criteria results in more or less than Mica's share of draft (based on its operating rule curve or proportional draft point as applicable) from the whole of Canadian Treaty Storage, compensating changes will be made from Arrow to the extent possible. The operation of Mica to specific Project Operating Criteria, together with compensating changes to Arrow's operation, is commonly called "Mica/Arrow Balancing".

A sample set of Mica operating criteria is shown in Table 3.

Mica operating criteria may require storage releases from Mica reservoir in excess of 8.6 cubic kilometers (7 million acre-feet) referenced in the Treaty. When possible, these releases will be held in Arrow reservoir and subsequently transferred back to Mica reservoir. This operation may cause losses to the U.S. if the Mica minimum release requirements prevent water from being transferred back to Mica prior to the time Arrow fills or reaches the Upper Rule Curve. Allowance for these losses, if any, is included as a reduction in the Downstream Power Benefits.

Table 3

Mica Project Operating Criteria

Illustrative Data from 2005/06 Assured Operating Plan

Period	English Units					Metric Units				
	End of Previous Period Arrow Storage Content Ksfd	Period Average Outflow cfs	End-of-period Content 1/ ksfd	Minimum Outflow cfs	Minimum Treaty Storage Content 2/ ksfd	End of Previous Period Arrow Storage Content hm^3	Period Average Outflow m^3/s	End-of-period Content 1/ hm^3	Minimum Outflow m^3/s	Minimum Treaty Storage Content 2/ hm^3
August 1-15	2600 -- Full	--	3499.1	15000	0.0	6361 -- Full	--	8560.9	424.8	0.0
	2160 -- 2600	25000	--	15000	0.0	5285 -- 6361	707.9	--	424.8	0.0
	0 -- 2160	32000	--	15000	0.0	0 -- 5285	906.1	--	424.8	0.0
August 16-31	3400 -- Full	--	3529.2	15000	0.0	8318 -- Full	--	8634.5	424.8	0.0
	1950 -- 3400	25000	--	15000	0.0	4771 -- 8318	707.9	--	424.8	0.0
	0 -- 1950	32000	--	15000	0.0	0 -- 4771	906.1	--	424.8	0.0
September	3440 -- Full	--	3524.1	10000	0.0	8416 -- Full	--	8622.1	283.2	0.0
	1900 -- 3440	22000	--	10000	0.0	4649 -- 8416	623.0	--	283.2	0.0
	1500 -- 1900	27000	--	10000	0.0	3670 -- 4649	764.6	--	283.2	0.0
	0 -- 1500	32000	--	10000	0.0	0 -- 3670	906.1	--	283.2	0.0
October	3275 -- Full	--	3344.1	10000	0.0	8013 -- Full	--	8181.7	283.2	0.0
	2530 -- 3275	20000	--	10000	0.0	6190 -- 8013	566.3	--	283.2	0.0
	1100 -- 2530	23000	--	10000	0.0	2691 -- 6190	651.3	--	283.2	0.0
	0 -- 1100	32000	--	10000	0.0	0 -- 2691	906.1	--	283.2	0.0
November	3030 -- Full	23000	--	12000	0.0	7413 -- Full	651.3	--	339.8	0.0
	2990 -- 3030	20000	--	12000	0.0	7315 -- 7413	566.3	--	339.8	0.0
	800 -- 2990	24000	--	12000	0.0	1957 -- 7315	679.6	--	339.8	0.0
	0 -- 800	32000	--	12000	0.0	0 -- 1957	906.1	--	339.8	0.0
December	2780 -- Full	25000	--	21000	4.1	6802 -- Full	707.9	--	594.7	10.0
	2450 -- 2780	23000	--	21000	4.1	5994 -- 6802	651.3	--	594.7	10.0
	600 -- 2450	30000	--	21000	4.1	1468 -- 5994	849.5	--	594.7	10.0
	0 -- 600	32000	--	21000	4.1	0 -- 1468	906.1	--	594.7	10.0
January	2340 -- Full	26000	--	15000	0.0	5725 -- Full	736.2	--	424.8	0.0
	2300 -- 2340	24000	--	15000	0.0	5627 -- 5725	679.6	--	424.8	0.0
	1240 -- 2300	29000	--	15000	0.0	3034 -- 5627	821.2	--	424.8	0.0
	0 -- 1240	31000	--	15000	0.0	0 -- 3034	877.8	--	424.8	0.0
February	1260 -- Full	22000	--	15000	0.0	3083 -- Full	623.0	--	424.8	0.0
	1070 -- 1260	20000	--	15000	0.0	2618 -- 3083	566.3	--	424.8	0.0
	760 -- 1070	25000	--	15000	0.0	1859 -- 2618	707.9	--	424.8	0.0
	0 -- 760	26000	--	15000	0.0	0 -- 1859	736.2	--	424.8	0.0
March	700 -- Full	20000	--	15000	0.0	1713 -- Full	566.3	--	424.8	0.0
	495 -- 700	19000	--	15000	0.0	1211 -- 1713	538.0	--	424.8	0.0
	100 -- 495	21000	--	15000	0.0	245 -- 1211	594.7	--	424.8	0.0
	0 -- 100	25000	--	15000	0.0	0 -- 245	707.9	--	424.8	0.0
April 1-15	1550 -- Full	16000	--	13000	0.0	3792 -- Full	453.1	--	368.1	0.0
	995 -- 1550	--	104.1	13000	0.0	2434 -- 3792	--	254.7	368.1	0.0
	730 -- 995	--	0.0	13000	0.0	1786 -- 2434	--	0.0	368.1	0.0
	0 -- 730	24000	--	13000	0.0	0 -- 1786	679.6	--	368.1	0.0
April 16-30	1240 -- Full	13000	--	10000	0.0	3034 -- Full	368.1	--	283.2	0.0
	1150 -- 1240	12000	--	10000	0.0	2814 -- 3034	339.8	--	283.2	0.0
	0 -- 1150	10000	--	10000	0.0	0 -- 2814	283.2	--	283.2	0.0
May	755 -- Full	10000	--	8000	0.0	1847 -- Full	283.2	--	226.5	0.0
	395 -- 755	8000	--	8000	0.0	966 -- 1847	226.5	--	226.5	0.0
	335 -- 395	14000	--	8000	0.0	820 -- 966	396.4	--	226.5	0.0
	0 -- 335	8000	--	8000	0.0	0 -- 820	226.5	--	226.5	0.0
June	1500 -- Full	10000	--	8000	0.0	3670 -- Full	283.2	--	226.5	0.0
	1075 -- 1500	8000	--	8000	0.0	2630 -- 3670	226.5	--	226.5	0.0
	630 -- 1075	10000	--	8000	0.0	1541 -- 2630	283.2	--	226.5	0.0
	0 -- 630	18000	--	8000	0.0	0 -- 1541	509.7	--	226.5	0.0
July	2330 -- Full	--	3449.1	10000	0.0	5701 -- Full	--	8438.6	283.2	0.0
	1870 -- 2330	18000	--	10000	0.0	4575 -- 5701	509.7	--	283.2	0.0
	0 -- 630	18000	--			0 -- 1541	509.7	--		
July	2330 -- Full	--	3449.1	10000	0.0	5701 -- Full	--	8438.6	283.2	0.0
	1870 -- 2330	18000	--			4575 -- 5701	509.7	--		
	0 -- 1870	30000	--			0 -- 4575	849.5	--		

1/ If the Mica target end-of-period storage content is less than full Treaty content, then a maximum outflow of 34000 cfs (962.8 m^3/s) will apply, except in April 1-15 when the maximum outflow is 29000 cfs (821.2 m^3/s)

2/ Mica outflows will be reduced to minimum to maintain the reservoir above the minimum Treaty storage content. This will override any target flow.

3 ASSURED OPERATING PLAN AND DOWNSTREAM BENEFIT COMPUTATION

3.1 GENERAL PROCEDURES

3.1.A INTRODUCTION

The Treaty requires that an Assured Operating Plan be prepared and agreed to each year for the sixth succeeding year of operation. This requirement is designed to ensure that an Assured Operating Plan will always be available for the five succeeding operating years. The plan will provide the Entities with essential information for effective operational planning of their respective power systems which are dependent on, or coordinated with, the operation of Canadian Treaty Storage.

The Treaty also requires that Downstream Power Benefit computations be prepared annually in conjunction with the Assured Operating Plan and shall define the Downstream Power Benefits in the U.S. from the operation of Canadian Treaty Storage for the applicable operating year. Downstream Power Benefit computations with reduced amounts of Canadian Treaty Storage are also carried out to define the limit to which Canadian Treaty Storage may be re-regulated to Canadian advantage so as to develop optimum power generation in Canada and the U.S., as described in Annex A, paragraph 7.

The Assured Operating Plan and Downstream Power Benefit computations shall reflect the requirements included in the Treaty, its Annexes and Protocol[3], Entity Agreements and other related documents. The studies necessary to develop the plan and determine the benefits shall be undertaken by the Entities jointly.

The Entities have agreed to develop the Assured Operating Plan for an August to July operating year.

3.1.B DATA REQUIREMENTS

Prior to 1 December of each year the Entities shall exchange information and data for the systems in the two countries not previously exchanged and which are necessary for development and completion of the Assured Operating Plan and the Determination of Downstream Power Benefits prior to 1 August. The information and data to be exchanged shall include:

- schedules for initial operation of power generating and storage facilities to be included in the studies;
- Pacific Northwest Area peak and energy load data;
- adjustments to project modified flows for the 30 historical years beginning with 1 August 1928;
- reservoir capacity;
- project water to energy conversion factors and peaking capacities throughout their operating range, and other plant data as necessary;
- suggested revisions to Base System and Libby non-power requirements and expected revisions to non-power requirements at other projects;

[3] Including, amongst other provisions, Articles IV and VII of the Treaty, Annex A, Annex B and paragraphs VIII, IX, and X of Protocol

- flood control criteria;
- maintenance and construction schedules; and
- any other data necessary to complete the studies.

Non-power requirements for Assured Operating Plan and Downstream Power Benefit studies for Base System projects and Canadian Treaty Storage are established in the 29 August 1996 Entity Agreement and can be changed only by mutual agreement. Non-power requirements for Libby to be used in the Assured Operating Plan studies are established in the Libby Coordination Agreement (referenced at Section 1.3(5)(f) of this document), and can be changed only by mutual agreement. See Appendix 2. Non-power requirements for other projects are the current best estimate of the non-power requirements expected to be implemented in actual operation.

3.1.C STUDY OUTLINE

Because the Assured Operating Plan and the Downstream Benefit Power computations are interdependent, their development is accomplished concurrently. This requires numerous hydroelectric planning studies, which have varying operating procedures and objectives depending on specific Treaty requirements.

Treaty Article III requires that all Base System projects, and all other main stem Columbia River hydro projects within the U.S., be operated to make the most effective use of the improvement of stream flows resulting from operation of the Canadian Treaty Storage for hydroelectric power generation in the U.S. power system, or that the studies used in the determination of the Downstream Power Benefit reflect this assumption.

Annex A paragraph 7 requires that, after the installation of generation at Mica, Canadian Treaty Storage “be operated in accordance with operating plans designated to achieve optimum power generation at site in Canada and downstream in Canada and the United States of America, including consideration of any agreed electrical coordination between the two countries”. Alternatively, by agreement, Annex A paragraph 8 allows operating plans designed to achieve optimum power in Canada alone or in the U.S. alone, with delivery of power by one country to off-set any reduction in generation in the other country. This Principles and Procedures document assumes that the Entities will prepare operating plans in accordance with Annex A paragraph 7, as they have every year since generators were installed in Mica.

Protocol paragraph VII(3) states that optimum power generation referred to in Annex A includes power at-site in Canada and downstream in Canada and the U.S., power generation in Canada that is coordinated therewith, the Treaty Downstream Power Benefits, power generation in the U.S. Pacific Northwest Area, and power generation coordinated therewith.

Annex B defines procedures for calculating the Downstream Power Benefits, defines the systems to be studied, and requires that the system be operated in accordance with the established operating procedures of each of the projects involved.

The Treaty requires a determination of the Downstream Power Benefits attributable to the agreed operation of Canadian Treaty Storage. To accomplish this, the Entities have agreed that the same project operating procedures and non-power requirements shall be used in all Assured Operating Plans and in the Downstream Power Benefit studies, apart from changes required to account for:

- different critical period lengths;
- different projects and storage amounts included in the studies; and

- different Canadian Treaty Storage operating criteria for studies required to operate to optimize U.S. generation compared to those required to operate to optimize generation in both countries.

(1) Step I, II and III Systems

In accordance with Annex B, paragraph 7 of the Treaty, the increase in dependable hydroelectric capacity and the increase in average annual hydroelectric energy, is determined from critical period and 30-year system regulation studies of the following systems:

> **Step I**: These studies establish the plant installation of the U.S. system required to serve the load of the Pacific Northwest Area, as further described in Section 3.2.B. These studies are also used to determine whether the proposed operating rules are optimum in both countries, as described below, and the final "joint optimum" study forms the basis of the Assured Operating Plan.
>
> **Step II**: These studies determine the critical period energy capability and the average annual usable hydro energy capability of a system that includes the same thermal installation as the Step I studies; the Base System projects with the same installed capacity as Step I; and the Canadian Treaty Storage.
>
> **Step III**: These studies are the same as Step II studies except Canadian Treaty Storage is not included.

The unregulated stream flows used in Steps I, II and III studies shall be based on the 30 years of stream flows, August 1928 to July 1958, contained in the Extension of Modified Flows report named in Protocol paragraph VIII, with updates for current best estimates of irrigation depletions, return flows, evaporation, and corrections for errors and omitted projects.

The unregulated stream flows used in the Step I study shall be used in the Step II and Step III studies, except for adjustments needed to reflect different upstream storage projects, e.g. Libby and Canadian Treaty Projects, and natural lake regulation.

In the initial years of operations under the Treaty, the Step I studies approximated the planned operation of the actual power system in Canada and the U.S. However, with the increase in non-power requirements applied to actual system operation since the early 1980's, the recent Step I studies have not reflected actual U.S. system operation, because of the Treaty requirement that the Downstream Power Benefits studies reflect the assumption that certain projects be operated for optimum power.

The Step II and Step III systems are not "real" power systems. Analysis of these "hypothetical" systems is required, because the Treaty provides that Canadian Treaty Storage benefits shall be considered as next added to the 13,000,000 acre-feet (16.035 cubic kilometers) of usable storage in the Base System (see Article VII paragraph 2(b)). The Step I study is primarily used to determine the appropriate installations for all three systems and to develop the operating plan for Canadian Treaty Storage. The Step II and Step III studies are used primarily to determine Downstream Power Benefits. However, all of the studies are interdependent and all are considered Downstream Power Benefit studies.

(2) Process and Data Flow

A total of seven system regulation studies are generally performed to complete the Assured Operating Plan and determine the Downstream Power Benefits. The basic assumptions for these studies and their general purpose are shown in Table 4 and the process and data flow is shown in Charts 5 and 6.

Table 4

Summary of Assured Operating Plan and Downstream Power Benefit System Regulation Studies

Study Name	Annex B Step #	System Configuration	Study Purpose / Description
US Optimum			
YR-11	1	15.5 Maf Cdn Treaty Storage **All U.S. Columbia Basin hydro projects** **Coordinated Cdn projects**	1) Establishes the power installations required, and U.S. Optimum generation which must be met or exceeded by Joint Optimum generation (using 3:1:2 weightings) derived in YR-41 study.
YR-12	2	15.5 Maf Cdn Treaty Storage **13.0 Maf Base System** PNW Area Load Shape Step I Thermal Installations	1) Compared to YR-13 study [no Treaty storage] to establish US optimum Downstream Power Benefits. 2) Compared to YR-42 study [Joint Optimum] to determine reduction, if any, in Downstream Power Benefits caused by Canadian re-operation.
YR-13	3	**No Treaty Storage 13.0 Maf Base System** PNW Area Load Shape Step I Thermal Installations	Base case for all Downstream Power Benefit computations. [Use of Base system defined in Annex B, provides Canada with the next-added benefits agreed to in Article Vll(2)(b) of the Treaty.]
YR-22	2	**15.0 Maf** Cdn Treaty Storage 13.0 Maf Base System PNW Area Load Shape Step I Thermal Installations	Compared against YR-12 study. 0.5 Maf reduction in Canadian Treaty Storage establishes a maximum **annual** reduction in Downstream Power Benefits and thereby limits amount of Canadian re-regulation.
YR-32	2	**12.5 Maf** Cdn Treaty Storage 13.0 Maf Base System PNW Area Load Shape Step I Thermal Installations	Compared against YR-12 study. 3.0 Maf reduction in Canadian Treaty Storage establishes a maximum **total** reduction in Downstream Power Benefits, and thereby limits amount of Canadian re-regulation. [The YR-32 study has never come close to being the operative constraint, and is therefore rarely completed.]
Joint Optimum (Re-regulation of YR-11, YR-12 Studies to Include Canadian Generation)			
YR-41	1	15.5 Maf Cdn Treaty Storage **All Columbia Basin hydro projects** Step I Load Shape Step I Thermal Installations **Coordinated Cdn projects**	Establishes operating plan for Canadian Treaty Storage, including Mica Operating Criteria, based on Joint Optimum generation (which must exceed U.S. Optimum generation from YR-11 study, using 3:1:2 weighting).
YR-42	2	15.5 Maf Cdn Treaty Storage **13.0 Maf Base System** PNW Area Load Shape Step I Thermal Installations	1) Compared to YR-13 study [U.S. Optimum] to establish final Downstream Power Benefits, based on Joint Optimum with Canadian Treaty Storage next-added to 13.0 Maf Base System Storage. 2) Compared to YR-12 study [U.S. Optimum] to determine reduction, if any, in Downstream Power Benefits caused by Canadian re-regulation. Downstream Power Benefit reduction must not exceed limits determined in YR-22 or YR-32 studies

Notes:
1) "YR" denotes Assured Operating Plan year. For example, 05-11 is the U.S. Optimum Step 1 study for 1 August 2004 to 31 July 2005.
2) 13 Maf (16.035 km^3) Base System defined in Annex B, includes 0.673 Maf (0.829 km^3) of usable storage at Kootenay Lake.
Cdn – Canadian
Maf – million acre-feet
PNW – Pacific Northwest

Chart 5

Process Flow Overview - Assured Operating Plan and Downstream Power Benefit Studies

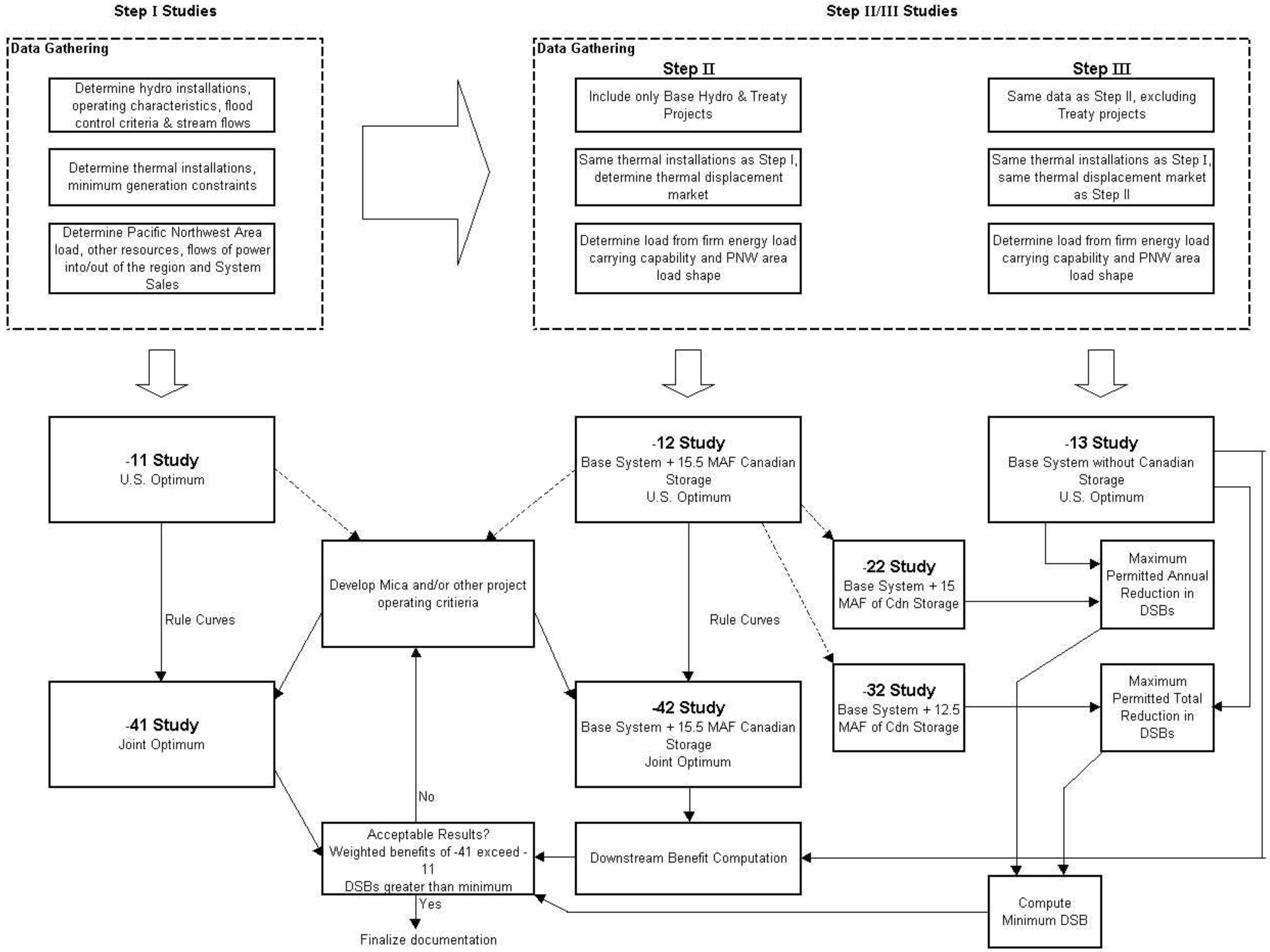
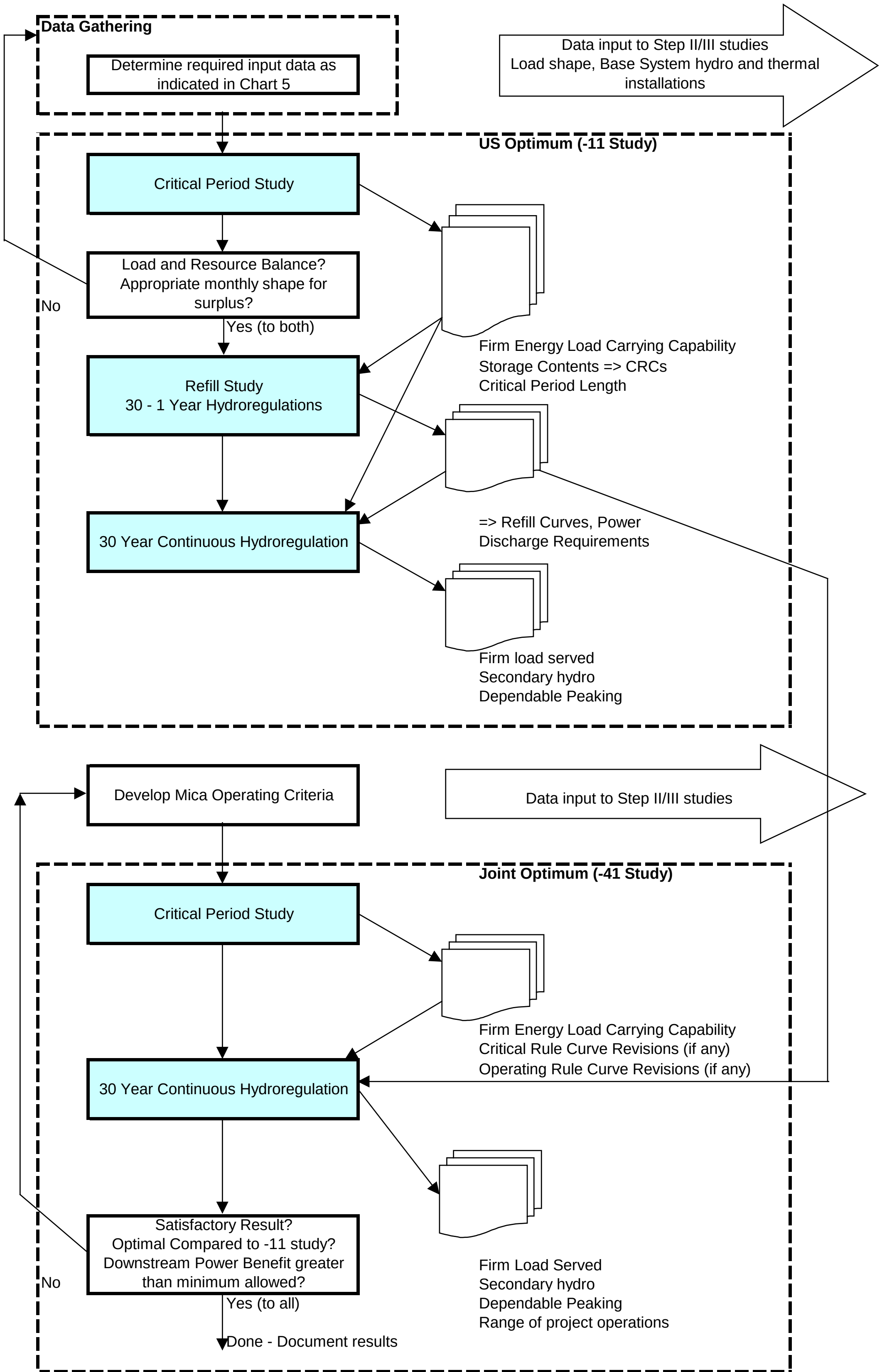


Chart 6

Detailed Process Flow - Step I Studies



As discussed earlier, this process and data flow assumes that the Assured Operating Plan is being developed in accordance with Annex A, paragraph 7 – i.e., optimum operation in both countries. In the event that the Entities decide to develop an Assured Operating Plan for optimum generation in either the U.S. alone or Canada alone, a similar schedule of studies to be performed shall be developed to insure compliance with the provisions of Annex A, paragraph 8.

The process begins with a study of the Step I system. The initial Step I study is a detailed system regulation of the Step I power system with the Canadian Treaty Storage operated to provide optimum power generation in the U.S. and is referred to as the YR-11 study ("YR" refers to the last two digits of the study year; e.g. the 2005-06 study is referred to as the 06-11 study). The thermal installations and Base System and Canadian Treaty Storage hydro installations from the Step I YR-11 study are carried over to studies of the Step II and Step III systems. The initial Step II study, with Canadian Treaty Storage operated for optimum power in the U.S. alone, is referred to as the YR-12 study. The Step III study, which excludes Canadian Treaty Storage and therefore is also operated for optimum power in the U.S. alone, is referred to as the YR-13 study. In these studies, optimum power generation is achieved by maximizing the firm energy load carrying capability of the U.S. system and operating to ensure a high probability (see Section 2.2.B)of refill.

The Treaty, in Annex A, paragraph 7, limits the amount of reduction in Downstream Power Benefits that may result from re-operation of Canadian Treaty Storage to optimize power generation in both countries. To determine the maximum permitted reduction in Downstream Power Benefits, two further studies of the Step II system are required. These studies are both operated to optimize generation in the U.S. alone, which, as above, is achieved by maximizing the firm energy load carrying capability of the U.S. system and operating to ensure a high probability of system refill. The YR-22 study includes only 15.0 million acre-feet (18.502 cubic kilometers) of Canadian Treaty Storage and is used to compute the maximum permitted annual reduction in Downstream Power Benefits that would result by reducing Canadian Treaty Storage by 0.5 million acre-feet (0.616 cubic kilometers) in one year. The YR-32 study includes 12.5 million acre-feet (15.419 cubic kilometers) of Canadian Treaty Storage and is used to compute the maximum cumulative permitted reduction in Downstream Power Benefits equivalent to reducing Canadian Treaty Storage by 3 million acre-feet (3.700 cubic kilometers). These maximum permitted reductions in Downstream Power Benefits are subsequently used to compute the minimum allowable Downstream Power Benefit for the applicable year. (See Section 3.3.A(3) for details of these computations.)

Once the studies of the U.S. optimum operation are complete, the next stage in the process is to develop project specific operating criteria for Mica, and possibly other projects, that optimize generation in both countries. These criteria are then included in studies of the Step I (YR-41) and Step II (YR-42) systems. Joint optimality of these criteria is tested by ensuring that the weighted sum of the U.S. and Canadian systems' firm energy, secondary energy and dependable capacity in the YR-41 study is greater than the corresponding total for the YR-11 study (see Section 3.2.A). In addition, the Downstream Power Benefits as determined by comparing the YR-42 study with the YR-13 study must exceed the minimum allowable Downstream Power Benefit as described above.

Once operating rules for Mica, or other projects, have been established that satisfy the optimality criteria and maintain Downstream Power Benefits above the minimum permitted levels, the YR-41 study becomes the basis for the Assured Operating Plan and the YR-42 and the YR-13 studies are used to compute the final Downstream Power Benefits.

3.2 DEVELOPMENT OF THE ASSURED OPERATING PLAN

3.2.A OBJECTIVES

The Treaty requires that an Assured Operating Plan be prepared and agreed to each year for the sixth succeeding year of operation. The plan is intended to provide the Entities with essential information on the operation of Canadian Treaty Storage required for effective operational planning of their respective power systems. The Treaty requires that studies used for Downstream Power Benefit computations operate certain projects in a manner that meets flood control and is optimal from a power perspective. However, many of these projects must meet other objectives and requirements in actual operation. As such, the objective of these Assured Operating Plan studies is to develop an operating plan for Canadian Treaty Storage that is as realistic as possible, within the confines of the Columbia River Treaty.

(1) Optimum Power Generation

As outlined in Section 3.1.C, there are two studies carried out of the Step I system for the Assured Operating Plan. The YR-11 study optimizes power generation in the U.S. alone by maximizing the firm energy load carrying capability of the U.S. system and operating to provide a high probability of system refill (see Section 2.2.B). In the YR-41 study, the operation of Canadian Treaty Storage is changed to achieve optimum power generation at-site in Canada and downstream in Canada and in the U.S. The YR-41 study is generally developed through an iterative process with the Canadian Treaty Storage operation modified from the YR-11 study to achieve optimum generation in both countries. Generally, the Mica project is operated to fixed rules similar to those outlined in Section 2.6. When possible, Arrow storage operation is modified to compensate for the changes in flows at the international boundary which would otherwise be caused by the change in Mica operation. The U.S. and Canadian Operating Rule Curves and Critical Rule Curves used in the YR-41 studies shall be changed from those used in YR-11 study only to the extent that U.S. reservoirs are required to balance Canadian Treaty Storage re-operation.

Because Arrow storage may not fully mitigate changes at Mica and other projects, there may be a net loss in the U.S. system relative to the U.S. optimum YR-11 study. Generally, losses to the U.S. system result from the following conditions:

- Water is trapped in Mica, and Arrow is empty or Arrow releases are restricted by a reduced maximum discharge capability, resulting in a decrease of water being released from Canadian Treaty Storage in a given period compared to that indicated in the U.S. optimum study. The deficit must then be compensated by U.S. reservoirs;
- Additional water is released from Mica in a period that Arrow storage is full or governed by flood control requirements and, therefore, unable to hold the additional water. Water is thus released at a time not required in the U.S.; and
- Minimum release requirements at Mica project prevent Mica Reservoir from refilling when all other projects in the basin refill. This may result in increased spill at downstream projects in the U.S., reduction in usable surplus or reduction in firm energy load carrying capability for the next operating year.

These losses to the U.S. system must be at least equaled by increases in the Canadian system for the modified Canadian Treaty Storage operation to be acceptable. To evaluate the power gains and losses in the Canadian and U.S. Step I systems, the Entities have agreed to a common measure, which is the weighted sum of each system's firm energy capability, dependable peaking capacity and average annual usable secondary energy capability. The relative weights assigned to each quantity are provided in the table below:

Quantity[4]	Relative Weight
Firm energy load carrying capability	3
Dependable peak capacity	1
Average annual usable secondary energy capability	2

These weighting factors may be changed by mutual agreement between the Entities. The values shown above have been utilized for all Assured Operating Plans adopted after the 1979-80 Assured Operating Plan dated September 1974.

The following sequential process is used to develop the optimal storage operation:

1. Canadian Treaty Storage in the Step I system is initially operated for optimum generation in the U.S. which maximizes the firm energy load carrying capability in the U.S. system (YR-11 study). The three quantities described above are then computed for both the Canadian and U.S. systems and a weighted sum is derived.
2. The Canadian Treaty Storage operation in the YR-11 study is then modified, in a trial YR-41 study, to achieve a weighted sum for Canada and the U.S. of the three quantities that is greater than the weighted sum achieved under operation for optimum generation in the U.S. alone. This step may require several iterations.
3. When a Canadian Treaty Storage operation is determined such that the weighted sum of the firm energy load carrying capability, dependable peak capacity, and average annual usable secondary energy capabilities are maximized and the Canadian Treaty Storage operating criteria provides acceptable levels of Downstream Power Benefits (see Section 3.3.A(3)), those criteria are adopted for the final YR-41 study and for inclusion in the Assured Operating Plan.

3.2.B DETAILS OF THE STEP I STUDIES

(1) Firm Load

The load to be served by the Step I system (see Annex B, paragraph 7), shall be the sum of:

- The load of the Pacific Northwest Area; including the power required for pumping water into Banks Lake from Grand Coulee reservoir[5]; and
- All flows of firm power out of the Pacific Northwest Area, except plant sales which are those flows of power from a generating facility located in the Pacific Northwest Area sold to serve loads outside the Pacific Northwest Area. (Included in this load out of the region is an estimate of the Entitlement that is expected to be used in Canada, based on

[4] The Entities define firm energy and dependable capacity in a manner that is applicable to their system. For example, firm energy load carrying capability for the U.S. system is derived from the U.S. critical period (typical 16 Aug 1928 through February 1932). For the Canadian system, the Canadian critical period is utilized (typically October 1940 through April 1946). Similarly, the U.S. uses January 1937 to determine dependable capacity, while Canada uses December 1944.

[5] The Entities have also included loads related to pumping requirements at Roza (a hydroelectric project on the Yakima River) in the determination of Pacific Northwest Area loads.

Entitlement calculations from the previous year's study. Iterative studies to correct the Entitlement amount are not performed if the estimate is sufficiently accurate.);

Reduced by:

- The load served by all flows of firm power into the Pacific Northwest Area, except power from Thermal Installations referred to in Annex B, paragraph 7;
- The load served by those hydro and non-thermal generating resources that are located in the Pacific Northwest Area and that are not included in the Step I system; and
- Any conservation added to balance loads and resources pursuant to subsection (3) below.

In the 1988 Entity Agreement (see reference at Section 1.3(5)(a) of this document), the entities developed procedures for implementing firm energy shifting within the studies for the Assured Operating Plan and Downstream Benefit Determinations. Firm energy shifting is an operation designed to increase firm energy load carrying capability in the current year, at the expense of load carrying capability in future years, if the system does not refill. These procedures have not been implemented in recent years and have been removed from the main body of this document. Nevertheless, firm energy shifting remains as an option available to the U.S. Entity and detailed implementation procedures are provided in Appendix 3.

(2) Surplus Firm Energy

Step I system firm energy capability in excess of the Step I system firm load shall be used to serve loads outside the Pacific Northwest Area (added to the flows of power out of the Pacific Northwest Area). This surplus firm energy load carrying capability may be shaped seasonally similar to the load that it is expected to serve.

(3) Added Resources

Any initial deficit in Step I system firm energy capability compared to the Step I system load shall be balanced by adding feasible resources and/or conservation consistent with current Pacific Northwest Area resource acquisition plans. Additional feasible resources may also be added to create a surplus which is then shaped seasonally in accordance with the expected flows out of the Pacific Northwest Area.

(4) Step I Resources

The resources included in the Step I system shall include:

- The Base System hydro projects (See Table 5);
- All other storage projects upstream of Bonneville Dam, including Canadian Treaty Storage, and U.S. hydroelectric projects upstream of Bonneville Dam; and
- The Thermal Installations (see below) that will be used to meet the Step I system loads.

The usable storage operating in the Step I study shall be the current best estimate of usable project storage.

The Step I study may, for convenience, include other resources that are not part of the Step I system. For example, certain U.S. hydro projects used to serve loads of the Pacific Northwest Area are included to aid in determining net Step I load. In addition, Canadian projects that are coordinated with Canadian Treaty Storage are included to aid in determining optimal power operation at site and downstream in Canada, including power generation coordinated therewith (Protocol VII(3))).

Table 5

Columbia River Treaty Base System

Project	**Stream**	**Capacity** MW (US only)	**Usable Storage** Base System km^3	Base System Maf	Actual km^3	Actual Maf
Hungry Horse	S. Fork Flathead	428	3.710	3.008	3.789	3.072
Kerr	Flathead	160	1.504	1.219	Same	Same
Thompson Falls	Clark Fork	85	--	--	--	--
Noxon Rapids	Clark Fork	554	--	--	0.285	0.231
Cabinet Gorge	Clark Fork	239	--	--	--	--
Albeni Falls	Pend Oreille	50	1.425	1.155	Same	Same
Box Canyon	Pend Oreille	74	--	--	--	--
Grand Coulee	Columbia	6684	6.256	5.072	6.396	5.185
Chief Joseph	Columbia	2535	--	--	--	--
Wells	Columbia	840	--	--	--	--
Rocky Reach	Columbia	1267	--	--	--	--
Rock Island	Columbia	513	--	--	--	--
Wanapum	Columbia	986	--	--	--	--
Priest Rapids	Columbia	912	--	--	--	--
Brownlee	Snake	675	1.201	0.974	1.203	0.975
Oxbow	Snake	220	--	--	--	--
Ice Harbor	Snake	693	--	--	--	--
McNary	Columbia	1127	--	--	--	--
John Day	Columbia	2484	--	--	0.660	0.535
The Dalles	Columbia	2074	--	--	--	--
Bonneville	Columbia	1088	--	--	--	--
Kootenay Lake	Kootenay	0	0.830	0.673	Same	Same
Chelan	Chelan	54	0.834	0.676	Same	Same
Coeur d’Alene Lake	Coeur d’Alene	0	0.275	0.223	Same	Same
Totals		23742	16.035	13.000	17.201	13.945

Note: The capacity value reflects the expected installed capacity (based on the 2005/06 Assured Operating Plan) as required by Treaty Article I, paragraph (b). These values may be higher than the expected ultimate installation documented in the similar table in Annex B of the Treaty.

(5) Thermal Installations

Thermal Installations, referred to in Annex B, paragraph 7, shall include the current best estimate for thermal power that will be used to meet the Step I system load, regardless of the location of the thermal power plants.

On July 22, 1998 the Columbia River Treaty Operating Committee further clarified and agreed to modify the procedures for determining thermal installations according to the following:

- Classification as a coordinated thermal installation is dependent on the flow of power from an identifiable project, a purchase of extra-regional system power does not qualify;
- The physical capability of the identified thermal projects should be included. All thermal installations with energy capability shaped seasonally for market or load reasons should have their resource capability adjusted to reflect the physical project capability, including maintenance outages. A balancing export load is also included, to reflect the

energy capability not expected to be used to serve Step I loads, so that the net effect is the same energy shape declared by the owner;

- Seasonal exchange exports are supported by seasonal exchange imports and therefore are excluded from the System Sales (see Exchanges of Firm Power, below);
- Thermal imports that are not coordinated thermal installations, including purchases of system power and capacity/energy exchange imports, act to support total exports because they are high marginal cost resources similar to thermal installations, and should be included as either flow-through transfers or seasonal exchanges. Thermal imports that do not originate from thermal installations and that are greater than total exports on a monthly basis, but not annually, should be included as seasonal exchanges; and
- Thermal import resources added to the Step I system when the system is deficit should be classified as thermal installations and included in the thermal displacement market only if they can be identified as corresponding to a specific existing or proposed thermal project.

(6) Exchanges of Firm Power

Contractual exchanges of firm power with other regions which neither increase nor decrease the net flow of power between the Pacific Northwest Area and other regions (seasonal exchanges) shall be treated as follows:

- Flows of power into the Pacific Northwest Area shall not be included as part of the Thermal Installations as described in Annex B, paragraph 7; and
- Flows of power out of the Pacific Northwest Area shall not be included as part of the thermal power used outside the Pacific Northwest Area, pursuant to subsection (8) System Sales below.

(7) Secondary Market and Thermal Displacement Market

In accordance with the 1988 and 1996 Entity Agreements (see reference at Section 1.3(5)(a), (b) and (c)), the secondary energy market limit used in the Assured Operating Plan Step I 30-year hydro regulation study to guide storage operation above the operating rule curves shall be determined in a manner similar to the operating procedures under the 1964 Pacific Northwest Coordination Agreement, plus any agreed modifications. Under these procedures the total secondary market is the sum of the total Southwest and Eastern markets plus the total within region thermal resources that are displaceable, as further described below:

- The total southwest and eastern market are determined from the intertie sizes (Idaho line plus Utah line, and the Pacific Northwest-Southwest lines) adjusted by a maximum capacity factor and reduced by total firm exports. The Southwest market is also adjusted by interconnection loop flow and maintenance requirements.
- The thermal resources that are displaceable is computed as the sum of all within region thermal resources (including all Thermal Installations used to serve loads of the Pacific Northwest Area) minus any minimum generation.

(8) System Sales

System sales are those flows of firm power out of the Pacific Northwest Area, excluding:

- flows of power from seasonal exchanges of firm power pursuant to subsection (6) Exchanges of Power above;
- plant sales;

- flow through transfers of power from outside the Pacific Northwest Area to outside the Pacific Northwest Area; and
- delivery of the Canadian Entitlement out of the Pacific Northwest Area.

(9) Step I Information Carried Over to the Determination of Downstream Power Benefits

Information developed in the Step I studies that is carried over to and utilized in the Step II and Step III studies, includes, but is not limited to, the following:

- the load shape of the Pacific Northwest Area;
- the installed capacity of the Base System;
- Project Operating Criteria;
- the Thermal Installations;
- flood control rule curves (as subsequently adjusted for Grand Coulee);
- the minimum generation of each Thermal Installation; and
- the System Sales.

In addition, the average of the Pacific Northwest Area monthly load factors during the Step I critical period (weighted by the number of days in each period) is also used in the determination of downstream power benefits (see Section 3.3.A(1) of this document).

3.2.C CONTENT OF THE ASSURED OPERATING PLAN

The following information used in or developed from the final YR-41 30-Year System Regulation Study shall form the Assured Operating Plan for the Canadian Treaty Storage for the particular operating year concerned. The Assured Operating Plan document shall be compiled by the Entities by 1 August of each year and shall contain the following:

1. The Critical Rule Curves for each Canadian Treaty project and for the whole of the Canadian Treaty Storage. The Critical Rule Curves shall be composed of the tabulated end of month storage contents for the water years which are included in the Critical Period System Regulation Study for the particular operating year;
2. Assured Refill Curves, Variable Refill Curves and Operating Rule Curve Lower Limits in terms of end-of-month storage content for each Canadian Treaty Storage project. Sample Variable Refill Curves are provided for each year of the historical period from 1928 to 1958. These project curves are used in development of Operating Rule Curves for the whole of Canadian Treaty Storage;
3. Upper Rule Curves for Mica, Arrow and Duncan projects, in terms of end-of-month storage content for each year of the historical period 1928 to 1958;
4. The Operating Rule Curve, in terms of end-of-month storage content for the whole of Canadian Treaty Storage, for each year of the historical period 1928 to 1958;
5. The Power Discharge Requirements, monthly stream flow distribution factors, forecast errors and Variable Refill Curve Lower Limits required for computation of Assured Refill Curves and Variable Refill Curves for Canadian Treaty Storage and for use in actual operation.
6. Project Operating Criteria, including Mica Project Operating Criteria, such as maximum/minimum target outflows, target end-of-month storage contents, and target flows as a function of Arrow reservoir storage contents;

7. Text, as required to supplement the tables above, including amplifying comments regarding operating rules, constraints, loads, resources, construction requirements, changes from the previous years study or other pertinent data unique to the operating year;
8. Summary of changes to loads, resources, operating procedures and other data compared to the prior operating year;
9. Reference to the specific hydro regulation model and study data used to develop the Step I joint optimum 30-year study, which serves as the basis for developing the Treaty Storage Regulation defined in the Detailed Operating Plan;
10. An implementation section consistent with Article XIV2(k) of the Treaty; and
11. Documentation of any agreed deviations from the currently applicable Principles and Procedures agreements.

3.3 DEVELOPMENT OF THE DOWNSTREAM POWER BENEFIT STUDIES

3.3.A OBJECTIVES

The Treaty requires that Downstream Power Benefit computations be prepared annually in conjunction with the Assured Operating Plan to define the Downstream Power Benefits in the U.S. from Canadian Treaty Storage operation for the applicable operating year. The Treaty also provides certain restrictions on the reduction in Downstream Power Benefits resulting from re-operation of Canadian Treaty Storage for optimal operation in both countries. The objectives for the Downstream Power Benefits studies therefore includes:

- Computation of the maximum permitted reduction in Downstream Power Benefits that may result from operating Canadian Treaty Storage for optimal power in both countries, relative to optimal power in the U.S. alone;
- Determination of the acceptability of the proposed operating criteria for Canadian Treaty Storage; and
- Computation of the final Downstream Power Benefits

(1) Method of Determining Downstream Power Benefits

The Canadian Entitlement to Downstream Power Benefits for any operating year, shall be one-half of the increase in dependable hydroelectric capacity and one-half the of the increase in average annual usable hydroelectric energy determined, as follows (See Table 9):

1. <u>Dependable Hydroelectric Capacity Benefit</u>: Subject to the capacity credit limit (see subsection (2) below) the capacity benefit from Canadian Treaty Storage shall be the difference between the average rates of generation during the critical periods of the Step II and Step III hydro systems divided by the average of the monthly load factors during the critical period of the Pacific Northwest area, as determined from the Step I study; and
2. <u>Average Annual Usable Hydroelectric Energy Benefits</u>: The energy benefit from Canadian Treaty Storage shall be the difference in the average annual usable energy of the Step II and Step III systems. The Entities have agreed (reference at Section 1.3(5)(a)) that, in the studies, all secondary hydro generation is used first for thermal displacement. As a result, the annual average usable energy for each system is the sum of:

- The annual firm hydro energy;
- The secondary hydro energy which can be used for thermal displacement; and
- The estimated amount of the remaining secondary generation which is agreed by the Entities to be usable, provided this amount does not exceed 40% of the remainder[6].

Prior to the 2003-04 Determination of Downstream Power Benefits, generation reductions of approximately 0.2% for step-up transformer losses were included at all U.S. federal projects. All plant data was updated in the 2003-04 studies to adjust for these losses, so this adjustment to study results is no longer necessary.

(2) Capacity Credit Limit

The capacity credit limit is described in Treaty Annex B, paragraph 2. and in the Protocol paragraph IX(2). These provisions specify that the capacity credit to Canadian Treaty Storage shall not exceed the difference between the firm load carrying capabilities of the projects and installations of the Step II and the Step III systems.

The capacity credit limit has not limited capacity entitlements in any Determination of Downstream Power Benefits carried out to-date, but it did apply in certain studies carried out to forecast the future levels of entitlement[7]. As such, detailed procedures for carrying out the studies required to determine the capacity credit limit have not been developed. Nevertheless, the general methodology to determine the capacity credit has been agreed to, as further described below.

The firm load carrying capability for each of the Step II and Step III systems is the greatest load that the system can serve, both peak and energy, while following the load shape of the Pacific Northwest Area. The firm load carrying capability may be limited by the system's installed capacity, its energy capability, or by a combination of these factors.

In the most recent Determination of Downstream Power Benefits (i.e. for the 2005/06 studies), the firm load carrying capability for the Step II and Step III studies was limited by the energy capability of those systems (see Table 7, line indicating "Surplus"). However, as thermal installations are added to these systems, the capacity surplus is expected to decline. When sufficient thermal resources are added, the capacity surplus will be reduced to zero and the installed capacity will begin to limit the firm load carrying capability. In such circumstances, the reservoir operation of the system may need to be changed to maximize the firm load carrying capability of the system. For example, when a system has an energy surplus and capacity is limiting (which is typical of systems that are predominately thermal), firm load carrying capability is maximized by ensuring hydro projects do not draft below elevations where their capacity is reduced. Such studies were called "critical head" studies in the original 1963 White Book forecast of entitlements.

Once installed capacity becomes limiting in both the Step II and Step III system, the capacity credit limit will diminish to zero. This is because both systems have the same installed capacity on the U.S. system, and if capacity is limiting, the firm load carrying capability of the systems will be identical. In this case, the Canadian Treaty Storage will continue to provide an energy benefit, but the capacity credit limit will limit the capacity entitlement to zero. Whether or not this will happen during the term of the Treaty will depend on actual load growth in the Pacific Northwest Area and the types of resources built to serve that load.

[6] In practice, the Entities have agreed that the 40% limit was applicable to all Downstream Power Benefit determinations to-date.

[7] For example, the capacity credit limit was applied in the "White Book" studies carried out in 1963 and in the "Entitlement Forecast Studies" undertaken by the Columbia River Treaty Operating Committee in April 1993.

The capacity credit limit is sensitive to the assumed level of required peak reserves and may be affected by the usability of the installed capacity and the scheduling of unit maintenance. Current studies include 8% peak reserve requirements[8], full usability of the installed hydro capacity and hydro maintenance modeled as a load adjustment in the Step I study only.

The following demonstrates how the capacity credit limit would be computed for the Determination of Downstream Power Benefits for 2005-06. The information for this example is taken from Table 7.

The firm load carrying capacity of Step II is the lesser of:

Step II capacity load	28,608	MW
Step II resources minus reserves	32,323	MW

Similarly, the firm load carrying capacity of Step III is the lesser of:

Step III capacity load	23,394	MW
Step III resources minus reserves	32,174	MW

Therefore, the capacity credit limit is (28,608 – 23,394) or	5,214	MW

The actual dependable capacity gain for this year was 2436 MW (see Table 9), well within the capacity credit limit.

(3) Minimum Permitted Downstream Power Benefits

Annex A, Paragraph 7, provides two specific limitations on any reduction in Downstream Power Benefits resulting from operating Canadian Treaty Storage to produce optimal power in both countries rather than optimal power in the U.S. alone. This limitation on the maximum reduction in Downstream Power Benefits can, in turn, be used to calculate the minimum permitted Downstream Power Benefits. As a result of these limitations, the actual Downstream Power Benefits must be not less than the higher of the two following values:

- The Downstream Power Benefits associated with 12.5 million acre-feet (15.4 cubic kilometers) of Canadian Treaty Storage; or
- The Downstream Power Benefits associated with the preceding year's benefits reduced by the effect of withdrawing 0.5 million acre-feet (0.6 cubic kilometers) of Canadian Treaty Storage.

A comparison of the YR-32 study to the YR-13 study provides the benefits of 12.5 million acre-feet (15.4 cubic kilometers) of Canadian Treaty Storage operated for optimum generation in the U.S. compared to the U.S. Base System operating alone. This limitation has not controlled the minimum permitted benefits through 2006, and the study has never come close to being the operative constraint, and is therefore rarely completed.

In addition to the allowable decrease equivalent to the withholding of 0.5 million acre-feet (0.6 cubic kilometers) of Canadian Treaty Storage, there is a normal decrease (or increase) from year-to-year due to changes in resources, irrigation depletions and other factors. Such increase/decrease is the difference between the benefits derived from the previous year's YR-12 and YR-13 studies, and the current year's YR-12 and YR-13 studies.

[8] Reserve requirements are generally established by each load serving entity in accordance with their own reliability criteria. For example, parties to the Pacific Northwest Coordination Agreement have adopted the "Loss of load expectation" methodology and have adopted a 1 in 20 years criteria. The required reserve can vary with the methodology employed and the adopted criteria. The 8% reserve requirement has been used in downstream benefit determinations since the earliest Treaty studies, and has not been reviewed for compliance with reliability criteria generally used in the Pacific Northwest Area.

Therefore, the minimum permitted benefit corresponding to the maximum annual reduction in benefits is computed as follows:

$DSB_{minimum}$ = Previous years benefits + natural change in benefits – reduction due to withdrawal of 0.5 million acre-feet (0.6 cubic kilometers) of Canadian Treaty Storage

Define:

X_p is the previous year's Downstream Power Benefits which were derived from the previous year's YR-42 study operated for optimum generation in both countries and the previous year's YR-13 study;

Y_p is derived from the previous year's YR-12 and YR-13 studies, both operated for optimum generation in the U.S.;

Y_c is derived from the current year's YR-12 and YR-13 studies, both operated for optimum generation in the U.S.; and

Z_c is derived from the current year's YR-22 study and the YR-13 study, both operated for optimum generation in the U.S.

Using the nomenclature above, $Yc\text{-}Y_p$ is the natural year-to-year change in Downstream Power Benefits, while $Yc\text{-}Z_c$ is the reduction in Downstream Power Benefits due to withdrawal of 0.5 million acre-feet (0.6 cubic kilometers) of Canadian Treaty Storage. As a result, the formula becomes:

$$\begin{aligned} DSB_{minimum} &= X_p + (Y_c - Y_p) - (Y_c - Z_c) \\ &= X_p - Y_p + Z_c \\ &= X_p - (Y_p - Z_c) \end{aligned}$$

The differences in capacity and energy derived from the YR-42 and YR-13 studies provide the computed Downstream Power Benefits for the year. The resulting benefits must not be less than the greater of the two minimum permitted benefits calculated above[9].

3.3.B DETAILS OF THE STEP II AND III STUDIES

(1) Resources

The Step II system resources include Canadian Treaty Storage, the Base System hydro projects, with the same installed capacity as in Step I, and the same Thermal Installations as were included in the Step I system. The Step III system resources are identical to the Step II system resources, except Canadian Treaty Storage is excluded.

The usable storage operated in the Step II and Step III studies for U.S. Base System projects shall be the amounts listed in Table 4 (under the heading "Base System"), except that Priest Lake is included and is regulated so as to model the effects of natural lake regulation on the inflows to downstream projects. This is accomplished by setting all rule curves to empty, so that only the channel outlet restriction causes a storage operation. Priest Lake inclusion is

[9] Another way to look at the limitation on Downstream Power Benefits is that the decrease in entitlement this year, due to re-operation of Canadian Treaty storage for joint optimum, must not be larger than the decrease last year, by more than the decrease this year due to a withdrawal of 0.5 million acre-feet (0.62 cubic kilometers) of Canadian Treaty Storage. The decrease last year can be derived from the previous years YR-12 and YR-42 studies (call this value U_p), the decrease this year is determined from the current years YR-12 and YR-42 studies (call this value U_c), and the decrease due to 0.5 Maf reduction in storage is determined from this years YR-12 and YR-22 studies (call this value V_c). This formula reduces to $U_c \leq U_p + V_c$

necessary because the 1960 Modified Flows mentioned in Protocol Paragraph VIII included the effect of natural lake regulation at Priest Lake, whereas modern Modified Flow reports do not.

In the YR-22 study, the Step II system Canadian Treaty Storage is reduced by 0.5 million acre-feet (0.6 cubic kilometers) (this is accomplished by restricting the minimum elevation at Mica). In the YR-32 study, the Step II system Canadian Treaty Storage is reduced by 3.0 million acre-feet (3.7 cubic kilometers). Again, this is accomplished by restricting the minimum elevation at Mica.

(2) Loads for Step II and Step III Studies

The firm energy load used in the Step II and Step III studies shall have the same monthly shape as the firm energy load of the Pacific Northwest Area (see Table 8).

The annual firm energy loads for Step II and Step III studies are set equal to the firm energy load carrying capabilities of those systems. The monthly firm energy loads for each system are determined using the iterative procedure described below and illustrated in Table 8:

1. Estimate the average hydro energy capability for the critical period of the system;
2. Add the corresponding critical period energy capability of the Thermal Installations to the critical period hydro energy capability above to obtain a total average critical period energy capability for the system;
3. Multiply the totals obtained in 2. above by the ratio

$$\frac{\text{PNW area average annual firm energy load}}{\text{PNW area average critical period firm energy load}}$$

   to obtain the average annual firm energy loads for the system;

4. Prorate the average annual firm energy loads determined in 3. in the ratio

$$\frac{\text{PNW area monthly firm energy load}}{\text{PNW area annual firm energy load}}$$

   to obtain the firm energy load for each month for the system; and

5. Subtract the monthly thermal energy capability to determine the monthly firm hydro energy loads for the system.

The average annual hydro energy loads for Step II and Step III systems also become the firm energy considered usable in the Downstream Power Benefit determination, as described in Section 3.3.A(1) and in accordance with Annex B, paragraph 3(a).

(3) Secondary Market

The secondary energy market limit used in the Step I study will also be used in the Step II and Step III studies.

(4) Thermal Displacement Market

The Thermal Displacement Market used in the computation of “average annual usable energy” is the displaceable portion of generation from the Step I Thermal Installations. The amount of Thermal Displacement Market for each month is defined by the following equation:

$$TD = TI - MG - SS$$

Where:

TD	=	The monthly thermal displacement market (only valid for positive numbers);
TI	=	The monthly generation capability of the Thermal Installations in the Step I system (the same installations are also used in the Step II and Step III systems);
MG	=	The monthly sum of the minimum amount of generation required from each Thermal Installation, as declared by the project operating agency or required by the minimum purchase provisions of a contract for a thermal resource; and
SS	=	The annual average amount of System Sales, prorated by month to give a uniform rate of delivery throughout the year.

3.3.C CONTENT OF THE DETERMINATION OF DOWNSTREAM POWER BENEFIT DOCUMENT

For convenience, this document is included as a component of the document titled "Assured Operating Plan And Determination Of Downstream Power Benefits". The Determination of Downstream Power Benefits Document shall include the following information:

1. The Canadian Entitlement, which is one-half the total computed Downstream Power Benefits for the adopted Assured Operating Plan;
2. One-half the minimum permitted Downstream Power Benefits, as indicated by Subsection 3.3.A.(3);
3. Tables and charts as follows (see examples following):
    - Determination of Firm Energy Hydro Loads for Step I Studies (Table 6A);
    - Determination of Firm Peak Hydro Loads for Step I Studies (Table 6B);
    - Determination of Thermal Displacement Market;
    - Summary of Power Regulations (Table 7);
    - Determination of Loads for Step II and III Studies (Table 8);
    - Computation of Canadian Entitlement (Table 9);
    - Duration Curves of Monthly Hydro Generation for the Step II and III systems (Chart 7); and
    - Text and tables supporting the computation of Downstream Power Benefits and illustrating the changes in Downstream Power Benefits over time;
4. Summary of changes to loads, resources, operating procedures and other data compared to the prior operating year; and
5. Documentation of any agreed deviations from the current Principles and Procedures agreements.

Table 6A

DETERMINATION OF FIRM ENERGY HYDRO LOADS FOR STEP I STUDIES (aMW)

Illustrative Data from the 2005/06 Determination of Downstream Power Benefits

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July	Annual Average	CP Ave 1/ (42.5 Mon)
1. Pacific Northwest Area (PNWA) Load	20911	20833	20401	21068	23016	24625	25199	24129	22794	21566	21655	21028	20876	21052	22214.7	22318.9
a) Annual Load Shape in Percent	94.13	93.78	91.83	94.84	103.61	110.85	113.43	108.62	102.61	97.08	97.48	94.66	93.97	94.76	100.0	100.5
2. Flows-Out of firm power from PNWA																
a) Canadian Entitlement Export (south+north)	269	269	269	269	269	269	269	269	269	269	269	269	269	269	268.6	268.6
b) Exports to the East	155	155	141	119	141	141	142	120	115	118	118	104	159	163	134.9	135.0
c) SW Seasonal Exchange Exports	195	195	229	14	0	0	0	0	0	0	0	24	155	166	65.6	63.6
d) Other SW Exports	574	574	568	514	471	479	481	462	388	385	421	469	594	594	500.0	500.3
e) Plant Sale Exports	106	106	106	106	106	106	106	106	106	106	101	88	106	106	104.5	104.8
f) Surplus Firm Energy Exports	700	700	600	0	0	0	0	0	0	0	2070	3740	2540	1845	876.9	765.2
g) Thermal Install. power used outside region	328	411	550	175	205	206	98	11	370	225	242	182	568	299	273.1	265.6
h) ...Subtotal	2327	2411	2462	1197	1192	1200	1095	967	1247	1103	3221	4876	4391	3443	2223.6	2103.2
i) Exclude Plant Sales	-106	-106	-106	-106	-106	-106	-106	-106	-106	-106	-101	-88	-106	-106	-104.5	-104.8
j) ...Total	2221	2304	2356	1091	1086	1094	989	861	1141	997	3120	4788	4285	3337	2119.1	1998.4
3. Load served by Flows-In of firm power except Step I thermal installations																
a) Non-thermal firm imports from north	-20	-20	-15	-21	-37	-47	-60	-69	-61	-29	-29	-28	-38	-26	-37.4	-37.7
b) Flows-in from SW seasonal exchanges	0	0	-1	-1	-162	-209	-179	-187	-39	-15	-6	0	0	0	-65.0	-72.3
c) Non-Coord. Thermal Resc. from SW (not TI)	-18	-18	-21	-33	-41	-41	-41	-41	-32	-31	-2	0	-7	-18	-25.8	-27.3
d) Added purchase/import of Sys Pwr from California	0	0	0	-500	-1078	-678	-1325	-1450	-925	-900	0	0	0	0	-528.0	-564.7
e) ...Total	-38	-38	-37	-554	-1318	-975	-1606	-1748	-1057	-975	-38	-28	-45	-44	-656.2	-702.0
4. Load served by non-Step I resources located within the PNWA																
a) Hydro Independents (1929 water)	-1282	-1255	-1175	-1201	-1231	-1159	-1102	-924	-1045	-1281	-1327	-1772	-1727	-1426	-1279.8	-1143.9
b) Non-Step I Coordinated Hydro (1929 water)	-511	-471	-556	-943	-956	-1007	-1046	-593	-688	-760	-789	-634	-1305	-792	-816.3	-842.5
c) Non-Thermal PURPA/NUGS	-107	-107	-99	-88	-95	-93	-94	-99	-96	-108	-107	-118	-117	-115	-102.4	-101.3
d) Miscellaneous Resources	-27	-27	-27	-27	-27	-27	-27	-27	-27	-27	-27	-27	-27	-27	-26.8	-26.8
e) ...Total (1929 water)	-1927	-1859	-1857	-2259	-2309	-2286	-2268	-1642	-1855	-2176	-2250	-2551	-3177	-2359	-2225.3	-2114.5
5. Total Step I System Firm Loads (1929 water) 2/	21167	21240	20863	19345	20474	22459	22314	21599	21022	19412	22486	23237	21939	21986	21452.4	21500.8
6. Step I Thermal Installations																
a) Large Thermal (includes plant sales)	4822	4822	4822	4822	4822	4822	4822	4822	4635	4587	4587	4275	4373	4822	4703.0	4721.2
b) Small Thermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2	0.2
c) Combustion Turbines	2026	2026	2029	2043	2045	2047	2057	2055	2052	1595	1243	1516	1748	1853	1907.4	1928.3
d) Cogeneration (includes plant sales)	1980	1979	1996	1985	1984	1980	1981	1983	1986	1994	1994	1763	1485	1975	1924.4	1933.5
e) Exclude Plant Sales	-106	-106	-106	-106	-106	-106	-106	-106	-106	-106	-101	-88	-106	-106	-104.5	-104.8
f) Thermal PURPA/NUGS	161	161	148	132	143	140	141	148	143	162	161	177	176	172	153.5	152.0
g) Thermals classified as Renewables	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63.2	63.2
h) Thermal Installation Imports from the East	1667	1667	1667	1616	1667	1667	1667	1667	1667	1335	1275	1457	1481	1667	1599.6	1608.7
i) ...Total	10612	10611	10619	10555	10617	10612	10625	10632	10440	9628	9222	9163	9219	10445	10246.8	10302.4
7. Total Step I Hydro Load (1929 water) 3/	10555	10629	10244	8790	9857	11846	11689	10968	10582	9783	13265	14075	12720	11541	11205.5	11198.4
a) Hydro Maintenance included as load	31	26	9	9	4	0	0	0	5	7	8	20	14	50	12.4	11.3
b) Coordinated Hydro Model Load (1929 water)	11097	11125	10809	9742	10817	12853	12735	11561	11275	10550	14061	14729	14039	12383	12034.2	12052.1

1/ The Step I critical period begins 16 August 1928 and ends 29 February 1932.

2/ Line 1+ line 2(j) + line 3(e) + line 4(e).

3/ Hydro load for U.S. projects located upstream of Bonneville Dam (except hydro independents), line 5 minus line 6(i).

Table 6B

DETERMINATION OF FIRM PEAK HYDRO LOADS FOR STEP I STUDIES (MW)
Illustrative Data from the 2005/06 Determination of Downstream Power Benefits

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July
1. Pacific Northwest Area (PNWA) Load	25829	25791	25657	28275	30423	32940	33621	32952	30597	28963	29035	27366	26356	25917
a) Annual Load Shape in Percent	80.80	80.80	79.51	74.51	75.65	74.76	74.95	73.22	74.50	74.43	74.43	76.84	79.21	81.23
2. Flows-Out of firm power from PNWA														
a) Canadian Entitlement Export (south+north)	588	588	588	588	588	588	588	588	588	588	588	588	588	588
b) Exports to the East	210	210	181	158	187	196	199	192	170	153	153	141	220	236
c) SW Seasonal Exchange Exports	465	465	465	120	15	15	15	15	15	15	15	60	450	465
d) Other SW Exports	937	937	970	944	843	810	810	769	769	769	819	920	927	927
e) Plant Sale Exports	122	122	122	122	122	122	122	122	122	122	122	51	122	122
f) Surplus Firm Peak Exports	866	866	755	0	0	0	0	0	0	0	2781	4867	3207	2271
g) Thermal Install. power used outside region	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h) ...Subtotal	3188	3188	3080	1932	1755	1731	1734	1686	1664	1647	4478	6627	5513	4610
i) Exclude Plant Sales	-122	-122	-122	-122	-122	-122	-122	-122	-122	-122	-122	-51	-122	-122
j) ...Total	3066	3066	2959	1810	1633	1609	1612	1564	1542	1525	4356	6577	5392	4488
3. Load served by Flows-In of firm power except Step I thermal installations														
a) Non-thermal firm imports from north	-146	-146	-146	-146	-155	-184	-207	-210	-212	-146	-146	-146	-146	-146
b) Flows-in from SW seasonal exchanges	0	0	0	0	-355	-376	-376	-376	-46	-12	-12	0	0	0
c) Non-Coord. Thermal Resc. from SW (not TI)	0	0	0	0	-3	-3	-3	-3	0	0	0	0	0	0
d) Added purchase/import of Sys Pwr from California	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) ...Total	-146	-146	-146	-146	-513	-563	-586	-589	-258	-158	-158	-146	-146	-146
4. Load served by non-Step I resources located within the PNWA														
a) Hydro Independents (1937 water)	-2050	-2028	-1937	-1787	-1633	-1594	-1548	-1664	-1787	-1995	-2003	-2169	-2209	-2116
b) Non-Step I Coordinated Hydro (1937 water)	-2579	-2495	-2598	-2548	-2447	-2372	-2241	-2054	-2048	-2074	-2113	-2228	-2395	-2581
c) Non-Thermal PURPA/NUGS	-114	-114	-108	-99	-102	-99	-98	-102	-105	-117	-117	-127	-129	-121
d) Miscellaneous Resources	-29	-29	-29	-29	-329	-329	-329	-329	-329	-29	-29	-29	-29	-29
e) ...Total (1937)	-4772	-4666	-4672	-4463	-4511	-4394	-4217	-4149	-4268	-4215	-4262	-4553	-4761	-4846
5. Total Step I System Firm Loads (1937water) 1/	23978	24046	23798	25477	27032	29593	30431	29778	27613	26116	28972	29244	26841	25413
6. Step I Thermal Installations														
a) Large Thermal (includes plant sales)	5365	5365	5365	5365	5365	5365	5365	5365	5100	5047	5047	4939	4847	5365
b) Small Thermal	38	38	38	41	41	41	41	41	41	38	38	38	38	38
c) Combustion Turbines	2125	2125	2134	2365	2376	2383	2396	2389	2380	2344	1905	1966	2139	2131
d) Cogeneration (includes plant sales)	2029	2029	2029	2018	2018	2018	2018	2018	2018	2029	2029	1784	1545	2029
e) Exlude Plant Sales	-122	-122	-122	-122	-122	-122	-122	-122	-122	-122	-122	-51	-122	-122
f) Thermal PURPA/NUGS	171	171	162	149	153	148	147	153	157	175	175	191	193	181
g) Thermals classified as Renewables	64	64	64	64	64	64	64	64	64	64	64	64	64	64
h) Thermal Installation Imports from the East	1463	1463	1407	1417	1524	1491	1578	1643	1320	1114	1114	1395	1084	1422
i) ...Total	11133	11133	11076	11296	11418	11387	11486	11550	10957	10689	10250	10326	9787	11108
7. Step I Hydro Load (1937 water) 2/	12845	12913	12722	14181	15614	18206	18944	18229	16656	15427	18722	18918	17054	14305
a) Hydro Maintenance included as load	4606	4043	3787	3208	2935	2037	1561	2289	2633	2751	2483	2360	2202	3721
b) Coordinated Hydro Model Load (1937 water)	20030	19451	19107	19937	20995	22615	22747	22572	21337	20251	23318	23505	21651	20607

1/ Line 1+ line 2(j) + line 3(e) + line 4(e).

2/ Hydro load for U.S. projects located upstream of Bonneville Dam (except hydro independents), line 5 minus line 6(i).

TABLE 7

SUMMARY OF POWER REGULATIONS
Illustrative Data from 2005/06 Determination of Downstream Power Benefits

PROJECTS	BASIC DATA				Step I		STEP II			STEP III		
	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE /4 kaf	hm^3	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	JANUARY 1945 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW
HYDRO RESOURCES												
CANADIAN												
Mica			7000	8635								
Arrow			7100	8758								
Duncan			1400	1727								
Subtotal			15500	19119								
BASE SYSTEM												
Hungry Horse	4	428	3072	3789	337	103	197	114	103	321	251	105
Kerr	3	160	1219	1504	179	116	175	112	129	174	160	123
Thompson Falls	6	85	0	0	85	53	85	53	58	85	66	57
Noxon Rapids	5	554	231	285	549	153	554	134	202	554	181	201
Cabinet Gorge	4	239	0	0	239	100	239	91	119	239	117	117
Albeni Falls	3	50	1155	1425	21	22	19	22	21	15	16	20
Box Canyon	4	74	0	0	71	45	70	45	48	69	57	47
Grand Coulee	24+3SS	6684	5185	6396	6365	2057	6364	1842	2393	5678	1243	2288
Chief Joseph	27	2535	0	0	2535	1069	2535	974	1308	2535	718	1239
Wells	10	840	0	0	840	421	840	390	490	840	292	443
Chelan	2	54	677	835	51	36	51	38	44	51	51	42
Rocky Reach	11	1267	0	0	1267	575	1267	533	694	1267	393	646
Rock Island	18	513	0	0	513	256	513	240	302	513	178	279
Wanapum	10	986	0	0	986	518	986	482	606	986	346	539
Priest Rapids	10	912	0	0	912	510	912	477	577	912	352	510
Brownlee	5	675	975	1203	675	240	675	313	323	675	274	321
Oxbow	4	220	0	0	220	99	220	124	128	220	121	128
Ice Harbor	6	693	0	0	693	212	693	231	302	693	168	302
McNary	14	1127	0	0	1127	622	1127	604	770	1127	465	718
John Day	16	2484	535	660	2484	939	2484	920	1254	2484	696	1216
The Dalles	22+2F	2074	0	0	2074	747	2074	730	992	2074	569	970
Bonneville	18+2F	1088	0	0	1047	566	1047	551	684	1047	440	642
Kootenay Lake	0	0	673	830	0	0	0	0	0	0	0	0
Coeur d'Alene Lake	0	0	223	275	0	0	0	0	0	0	0	0
Total Base and Canadian System Hydro 1/		23742	29445	36320	23268	9459	23126	9018	11546	22559	7154	10953
ADDITIONAL STEP I PROJECTS												
Libby	5	600	4980	6143	532	192						
Boundary	6	1055	0	0	855	368						
Spokane River Plants 2/	24	173	104	128	168	100						
Hells Canyon	3	450	0	0	450	192						
Dworshak	3	450	2015	2486	443	145						
Lower Granite	6	932	0	0	930	212						
Little Goose	6	932	0	0	928	204						
Lower Monumental	6	932	0	0	922	211						
Pelton, Rereg., & RB	7	423	274	338	420	128						
Total added step 1		5947	7373	9095	5649	1751						
THERMAL INSTALLATION					11486	10302	11486	10325		11486	10498	
RESERVES, HYDRO MAINTENANCE 3/					-4251	-11	-2289	0		-1872	0	
TOTAL RESOURCES					36152	21501	32323	19343		32174	17652	
STEP I, II, & III LOADS					30431	21501	28608	19343		23394	17652	
SURPLUS					5721	0	3715	0		8780	0	
CRITICAL PERIOD	Starts				August 16, 1928		September 1, 1943			November 1, 1936		
	Ends				February 29, 1932		April 30, 1945			April 15, 1937		
	Length (Months)				42.5 Months		20 Months			5.5 Months		
	Study Identification				06-41		06-42			06-13		

1/ The above totals are correct, but may not equal the sum of the above values due to rounding.

2/ Spokane River Plants include: Little Falls, Long Lake, Nine Mile, Monroe, U Falls, and Post Falls.

3/ Peak reserves for Step I, II, III are 8 percent of January peak load. Energy reserve deductions only include the hydro maintenance for Step I study (reserves have been included in thermal plant energy capability).

4/ Mica, Arrow and Duncan are not included in Step III studies. For Step II and III studies, the usable content at Hungry Horse is 3008 kaf, Grand Coulee is 5072 kaf, Brownlee is 974 kaf, Chelan is 676 kaf, and Noxon and John Day are zero (See Table 4).

Table 8

DETERMINATION OF LOADS FOR STEP II AND STEP III STUDIES

Illustrative Data from 2005/06 Determination of Downstream Power Benefits

		STEP I STUDY Critical Period: Aug 16, '28 - Feb 29, '32							ALL STUDIES	STEP II STUDY Critical Period: Sep 1, '43 - Apr 30, '45					STEP III STUDY Critical Period: Nov 1, '36 - Apr 15, '37				
Period	Days in Period 1/	Periods in 42.5 Month Critical Period	Leap Days	Days in Critical Period 2/	PNWA Energy Load (aMW) 3/	Annual Energy Load Shape 4/	PNWA Peak Load (MW) 3/	Load Factor 5/	Energy Capability of Step I Thermal Installations (aMW) 6/	Periods in 20 Month Critical Period	Leap Days	Days in Critical Period 2/	Total Load (aMW) 7/	Hydro Load (aMW) 8/	Periods in 5.5 Month Critical Period	Leap Days	Days in Critical Period 2/	Total Load (aMW) 7/	Hydro Load (aMW) 8/
August 1-15	15	3		45	20,911	94.13%	25,829	*80.80%*	10,612.0	1		15	17,999.1	7,387.1	0		0	15,548.7	4,936.6
August 16-31	16	4		64	20,833	93.78%	25,791	*80.80%*	10,611.0	1		16	17,932.0	7,321.0	0		0	15,490.7	4,879.7
September	30	4		120	20,401	91.83%	25,657	79.51%	10,618.9	2		60	17,560.1	6,941.2	0		0	15,169.4	4,550.5
October	31	4		124	21,068	94.84%	28,275	74.51%	10,554.7	2		62	18,134.1	7,579.3	0		0	15,665.3	5,110.5
November	30	4		120	23,016	103.61%	30,423	75.65%	10,617.3	2		60	19,810.9	9,193.6	1		30	17,113.8	6,496.5
December	31	4		124	24,625	110.85%	32,940	74.76%	10,612.3	2		62	21,196.3	10,584.0	1		31	18,310.6	7,698.3
January	31	4		124	25,199	113.43%	33,621	74.95%	10,624.8	2		62	21,690.4	11,065.6	1		31	18,737.4	8,112.7
February	28	4	1	113	24,129	108.62%	32,952	73.22%	10,631.8	2	1	57	20,768.9	10,137.2	1	0	28	17,941.4	7,309.6
March	31	3		93	22,794	102.61%	30,597	74.50%	10,440.3	2		62	19,619.9	9,179.6	1		31	16,948.8	6,508.5
April 1-15	15	3		45	21,566	97.08%	28,963	*74.43%*	9,628.4	2		30	18,563.2	8,934.7	1		15	16,035.9	6,407.5
April 16-30	15	3		45	21,655	97.48%	29,035	*74.43%*	9,221.9	2		30	18,639.5	9,417.6	0		0	16,101.9	6,880.0
May	31	3		93	21,028	94.66%	27,366	76.84%	9,162.6	1		31	18,099.8	8,937.2	0		0	15,635.7	6,473.1
June	30	3		90	20,876	93.97%	26,356	79.21%	9,219.3	1		30	17,969.4	8,750.1	0		0	15,523.0	6,303.7
July	31	3		93	21,052	94.76%	25,917	81.23%	10,445.0	1		31	18,120.5	7,675.4	0		0	15,653.5	5,208.5
Annual weighted average 1/ =					22,214.7	100.00%		76.66%	10,246.8			Sum=608	19,121.6	8,874.7			Sum=166	16,518.3	6,271.5
Step I CP weighted average 2/ =					22,318.9	100.47%		**76.54%**	10,302.4										
Step II CP weighted average 2/ =						101.16%		9/	10,324.8				19,343.3	**9,018.5**					
Step III CP weighted average 2/ =						106.86%			10,497.8									17,651.9	**7,154.1**
													Input 10/	9,018.5				Input 10/	7,154.1

1/ The Annual Weighted Average is for the non-leap-year 2005-06 operating year.
2/ The number of days used in computing weighted averages varies with the length of the critical periods determined for the Step I, II and III Studies.
3/ The Pacific Northwest Area (PNWA) firm load does not include exports, but does include pumping.
4/ The Step I study energy load shape is used to compute the Step II and III studies total energy loads.
5/ Whole month load factors for August and April are computed by dividing the whole month energy values by the larger of the two split month peak values.
6/ The thermal installations include all thermal used to meet the Step I system load.
7/ The annual average total energy load for the Step II and III studies is calculated from the estimated hydro CP energy load, plus the CP thermal energy capability, divided by the CP weighted average energy load shape. The monthly total loads are computed to have the same shape as the load of the PNWA (from Step I).
8/ The hydro load is equal to the total load minus the Step I study thermal installations for each period.
9/ The Step I CP weighted average load factor is used to calculate the Dependable Capacity Gain credited to Canadian Storage.
10/ The estimated CP weighted average generation for the Step II and Step III hydro studies is derived by inputing an initial guess, checking the output and iterating until input and output match

TABLE 9

COMPUTATION OF CANADIAN ENTITLEMENT
Illustrative Data from the 2005/06 Determination of Downstream Power Benefits

A. Joint Optimum Power Generation in Canada and the U.S. (From 06-42)
B. Optimum Power Generation in the U.S. Only (From 06-12)
C. Optimum Power Generation in the U.S. and a 0.5 Million Acre-Feet (0.6 km^3) Reduction in Total Canadian Treaty Storage (From 06-22)

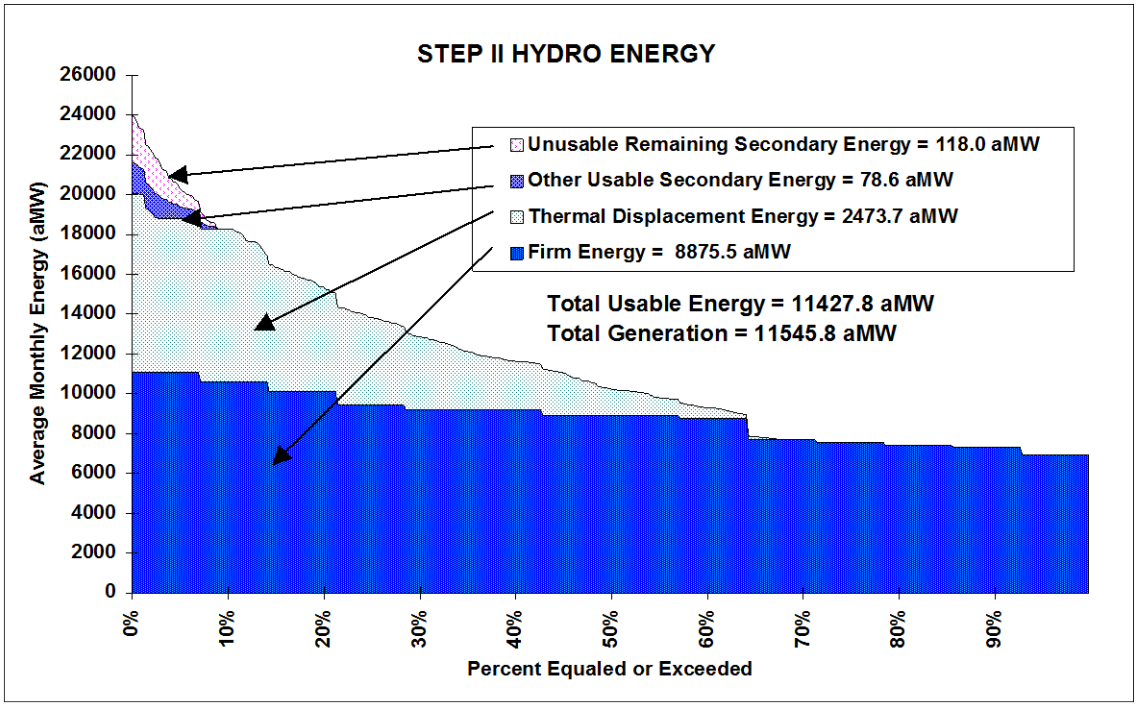
Determination of Dependable Capacity Credited to Canadian Storage (MW)	CAPACITY ENTITLEMENT		
	(A)	(B)	(C)
Step II - Critical Period Average Generation 1/	9018.5	9018.5	8976.4
Step III - Critical Period Average Generation 2/	7154.1	7154.1	7154.1
Gain Due to Canadian Storage	1864.4	1864.4	1822.3
Average Critical Period Load Factor in percent 3/	76.54	76.54	76.54
Dependable Capacity Gain 4/	2436.0	2436.0	2381.0
Canadian Share of Dependable Capacity 5/	1218.0	1218.0	1190.5

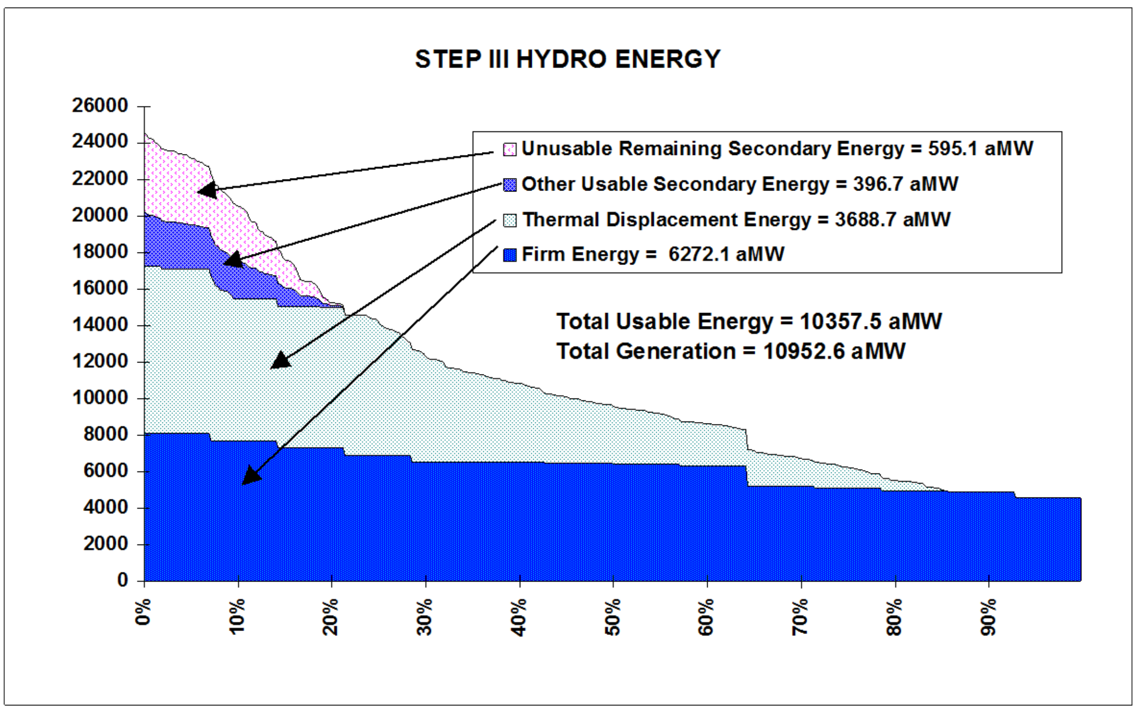
Determination of Increase in Average Annual Usable Energy (aMW)	ENERGY ENTITLEMENT		
Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Annual Firm Hydro Energy 6/	8875.5	8875.5	8833.9
Thermal Displacement Energy 7/	2473.7	2469.7	2500.8
Other Usable Secondary Energy 8/	78.6	78.9	81.3
System Annual Average Usable Energy	11427.8	11424.1	11416.0
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6272.1	6272.1	6272.1
Thermal Displacement Energy 7/	3688.7	3688.7	3688.7
Other Usable Secondary Energy 8/	396.7	396.7	396.7
System Annual Average Usable Energy	10357.5	10357.5	10357.5
Average Annual Usable Energy Gain 9/	1070.3	1066.6	1058.5
Canadian Share of Average Annual Energy Gain 5/	535.1	533.3	529.3

1/ Step II values were obtained from the 06-42, 06-12, and 06-22 studies, respectively.
2/ Step III values were obtained from the 06-13 study.
3/ Critical period load factor of PNW area load from Step I study.
4/ Dependable Capacity Gain credited to Canadian storage equals gain in critical period average generation divided by the average critical period load factor.
5/ One-half of Dependable Capacity or Usable Energy Gain.
6/ From 30-year average firm load served, which includes 7 leap years (29 days in February).
7/ Average secondary generation limited to Potential Thermal Displacement market.
8/ Forty percent (40%) of the remaining secondary energy.
9/ Difference between Step II and Step III Annual Average Usable Energy.

Chart 7

DURATION CURVES OF 30 YEARS MONTHLY HYDRO GENERATION (aMW)
Illustrative Data from 2005/06 Downstream Power Benefit Studies





4 DETAILED OPERATING PLAN

4.1 GENERAL

Each year a Detailed Operating Plan may be developed for the whole of the Canadian Treaty Storage, including constraints and operating criteria that may apply to individual reservoirs. The Detailed Operating Plan shall be developed, as described below, from the Assured Operating Plan previously agreed to for that operating year, unless otherwise agreed. Planning for the Detailed Operating Plan generally begins in December for the August through July operating year immediately following, with the intent of completing the plan prior to the start of the operating year.

4.2 DEVELOPMENT OF THE DETAILED OPERATING PLAN

The process for development of the Detailed Operating Plan has evolved over time and is designed to identify and evaluate proposed changes to the Assured Operating Plan that would be mutually advantageous to the Entities. The process is illustrated in Chart 8. This process provides for the potential inclusion of operating procedures to address non-power issues that may be precluded from inclusion in the Assured Operating Plan. The Detailed Operating Plan generally includes implementation procedures that allow for the further refinement of the operating plan throughout the operating year as more information becomes available about the current stream flow conditions.

The process begins with a review of the Assured Operating Plan for the next operating year. A number of system regulation studies are then carried out to evaluate proposed changes to the operating plan. Coincident with this process, the U.S. Entity carries out a parallel operations planning process required by the Pacific Northwest Coordination Agreement. Although this is not part of the Treaty process, information developed during the development of the Detailed Operating Plan is essential for the Pacific Northwest Coordination Agreement process and information developed in the Pacific Northwest Coordination Agreement process, if advantageous to both Entities, may contribute to the Detailed Operating Plan.

4.2.A REVIEW OF THE ASSURED OPERATING PLAN

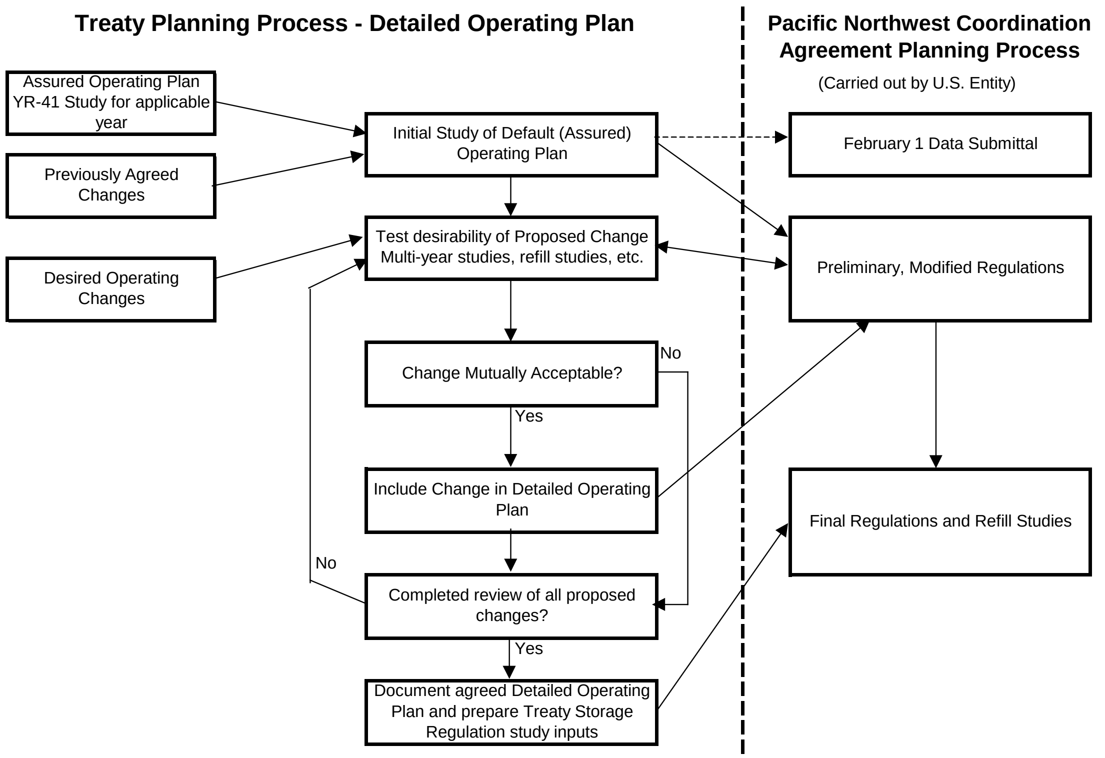
The Canadian and U.S. Entities shall review the Assured Operating Plan applicable to the immediately ensuing operating year. Changes in system load estimates, energy shifting assumptions, resources, duration of the critical period, flood control criteria, irrigation depletions, non-power requirements, and any other pertinent data shall be considered in this review using the latest available data in comparison with that used in the original study. If the Entities agree that these changes warrant further investigation, joint studies analyzing the impacts of implementing the proposed change shall be made.

The Entities shall agree on the need for revisions to the Critical Period Rule Curves or other operating criteria for Canadian Treaty Storage. To facilitate U.S. planning studies, the Entities shall make all reasonable effort to agree by 1 February. If the necessity for revised Critical Period Rule Curves and operating criteria for Canadian Treaty Storage cannot be agreed upon, the Detailed Operating Plan shall be based on the Assured Operating Plan referenced in the first paragraph of this section (recognizing that the U.S. Entity may have an option to implement alternative shift or non-shift firm energy operating criteria in accordance with Appendix 3).

In accordance with Section 6-6 of the Flood Control Operating Plan, the Canadian Entity may exercise an option to operate to a flood control allocation between Mica and Arrow that is different than that which was used in the Assured Operating Plan referred to in the first paragraph of this section. If the Canadian Entity exercises this option, then the Entities will agree on procedures to ensure the same Treaty flows at the U.S.-Canada border as that provided in the Assured Operating Plan referred to in the first paragraph of this section, unless otherwise mutually agreed.

Chart 8

Process Flow Overview - Detailed Operating Plan



4.2.B SYSTEM REGULATION STUDIES

A number of system regulation studies are used to test the default operating criteria and to develop potential new operating criteria. Such studies typically include the following:

(1) Historic Water Sequence System Regulation Study

A "Historic Water Sequence System Regulation Study" is the primary tool used to evaluate current and proposed operating criteria. This study is similar to the 30-year regulation studies carried out for the Assured Operating Plan except that, by agreement, additional water years from the historical record may be included. In recent years, most Historic Water Sequence System Regulation Studies have included 50 or 60 years of historical modified flow data. These studies cycle through all years of data in a "continuous" study – i.e. the same load and resource conditions are applied to all operating years and the ending elevations for each historical water year become the starting elevations for the next water year.

A preliminary Historic Water Sequence System Regulation Study shall be made by using the Assured Operating Plan Step I hydro regulation (-41) study. In general, the following adjustments are made to facilitate using the most recent information and computer models:

- changes to plant characteristics;
- agreed updates to current operating data relating to the current version of the computer model; and
- revised Upper Rule Curves, if applicable, incorporating updated flood control requirements, for all historic water sequences.

In addition, certain data that cannot be duplicated in actual operations, or is not readily available in a timely manner during the operating year, is replaced with a best estimate. The purpose of these changes is to incorporate into this study all data changes expected to be implemented in the Treaty Storage Regulation (see Section 4.2.C) which will guide the operation of Canadian Treaty Storage during the operating year. This allows all potential operation changes to be evaluated with the best estimate of the expected operation of Canadian Treaty Storage. These changes are as follows:

- fixed project operations are removed and a secondary market is included in the critical period of the study (in Assured Operating Plan studies, during the critical period, projects are forced to follow their Critical Rule Curves even if normal operating criteria would indicate otherwise);
- Brownlee reservoir is operated to its proportional draft point instead of any fixed operation that may have been included in the Assured Operating Plan; and
- the energy production of the independent hydro resources for each year of the Historic Water Sequence System Regulation Study is replaced with the 60-year median values for the projects that do not have forecasted data in the Treaty Storage Regulation study.

Several other studies may also be required to test and evaluate proposed changes to the operating criteria (any changes from the original Assured Operating Plan study must be agreed to by the Entities).

The final study provides the Entities with a good estimate of the potential range of Canadian Treaty Storage draft rights and obligations for the next operating year. After the study is agreed to by the Operating Committee, the operating criteria and data inputs for both Canadian and U.S. projects will be used to determine Canadian Treaty Storage operation based on the unregulated stream flows that actually develop during the operating year and the Upper Rule Curves and Variable Refill Curves that are computed during the year. The method for determining Canadian Treaty Storage operation in this manner is described in greater detail in Sections 4.2.C and 4.4.

(2) Pacific Northwest Coordination Agreement Studies

The agreed Canadian Treaty Storage operation is used by the U.S. Entity to develop operating plans for the U.S. system. The operating plans are developed by the U.S. Entity as part of the Pacific Northwest Coordination Agreement. During the study process, the U.S. Entity may propose to the Canadian Entity suggested changes in Canadian Treaty Storage operation. Such changes will be incorporated into the Detailed Operating Plan and corresponding Multi-year System Regulation Studies only by mutual agreement.

The process used to develop the U.S. operating plans requires the development of three Critical Period System Regulation studies and a Refill Study as follows

- a Preliminary Regulation study to test the initial data submitted, determine the critical period, determine the preliminary maximum critical period energy capability, and to develop suggested changes for inclusion in later studies;
- a Modified Regulation study to test proposed data changes, improve distribution of energy over the critical period, and to further develop suggested changes to operation;
- a Final Regulation study which may improve the regulation for each individual party's system, and to demonstrate the operation for the final accepted data; and
- a Refill Study with the original objective of reducing refill failures[10] caused by producing non-firm energy, thereby protecting the system's ability to produce next year's firm energy load carrying capability.

In recent years, due largely to non-power constraints on the reservoir system, the U.S. system has adopted a one-year critical period for its planning studies. As a result, any proposed changes from the Pacific Northwest Coordination Agreement process, can be accommodated within the Detailed Operating Plan for the next operating year. If the U.S. studies produced a multi-year critical period (as generally occurred prior to 1995), the U.S. Entity may request changes to Assured Operating Plan requirements for several future years. This process is described in further detail in Appendix 4.

Pacific Northwest Coordination Agreement planning studies for the operation of U.S. projects currently include many fisheries objectives. Canadian Treaty Storage operation as determined by the Assured Operating Plans does not include system-wide fisheries objectives, although certain at-site non-power requirements related to fisheries are included. Fisheries objectives are only included in the Detailed Operating Plan by mutual agreement and, in general, agreement has not been obtained until later in the operating year (see Section 4.4.D on Supplemental Operating Agreements). As a result, the agreed Canadian Treaty Storage operation defined in the Detailed Operating Plan agreed to at the beginning of the operating year is maintained in any subsequent U.S. studies by fixing the Canadian operation to the agreed Detailed Operating Plan.

4.2.C ARRANGEMENTS FOR IMPLEMENTATION

The operating criteria from the final agreed-upon Historic Water Sequence System Regulation Study will be incorporated into a one-year system regulation study referred to as the Treaty Storage Regulation. This system regulation study will be used to guide actual operation of Canadian Treaty Storage during the year as further described in Section 4.4. During the course of the year, the unregulated stream flow data, the Variable Refill Curves, and the Upper Rule Curves input to the Treaty Storage Regulation study will be modified to reflect actual conditions. The Treaty Storage Regulation will use this data, along with all of the other project operating data previously incorporated in the study, to determine the Canadian Treaty Storage operation consistent with the Detailed Operating Plan.

[10] The ability of the reservoir system to meet the original refill objectives is limited due to the major U.S. projects operating for fisheries objectives, therefore, Refill Studies are currently only conducted to measure the ability to refill under current operating criteria.

4.2.D DELIVERY OF POWER AND ENERGY

If necessary, prior to the operating year, the Entities shall agree on procedures for scheduling the delivery of any exchanges of energy or power included in the Detailed Operating Plan and/or other agreements between the Entities.

4.3 CONTENT OF DETAILED OPERATING PLAN

The Detailed Operating Plan shall be compiled by the Entities by 1 August, and shall consist of at least the data and criteria listed below:

1. Distribution of usable Canadian Treaty Storage available for power and flood control purposes;
2. The amount and procedures for delivery of any power deliveries between the Entities required by the operating plan and/or agreements between the Entities;
3. Operation authority and objectives for Canadian Treaty Storage;
4. Description of the arrangements for implementation of the Detailed Operating Plan, including agreed Treaty Storage Regulation study inputs;
5. Agreed operating rules, project operating criteria and project operating limits for Canadian Treaty Storage;
6. Procedure for determining the Operating Rule Curves for inclusion in the Treaty Storage Regulation (see Section 4.4) for each of the Canadian reservoirs;
7. Critical Rule Curves for each of the Canadian reservoirs and for the whole of the Canadian Treaty Storage tabulated in terms of end-of-month storage contents, as agreed to by the Entities;
8. Assured Refill Curves for each of the Canadian Treaty Storage reservoirs tabulated in terms of month-end storage contents, as agreed to by the Entities;
9. Data required for determining the Variable Refill Curves;
10. Reference to the Treaty Storage Regulation study model, the firm loads and resources and any other data including any significant change from the Assured Operating Plan;
11. Any additional supplementary text or tables required to limit or clarify the intended operation of Canadian Treaty Storage;
12. Storage-elevation tables for Mica, Arrow and Duncan projects; and
13. Documentation of any agreed deviations from current Principles and Procedures documents.

4.4 DETAILED OPERATING PLAN IMPLEMENTATION

4.4.A TREATY STORAGE REGULATION STUDY

Implementation of the Detailed Operating Plan is achieved through a Treaty Storage Regulation study run to determine monthly storage rights and obligations for the Canadian reservoirs Mica, Arrow, and Duncan. The Operating Committee must agree to procedures used to derive all inputs to Treaty Storage Regulation studies. These procedures are documented in Assured Operating Plans, Detailed Operating Plans, Hydrometeorological Committee reports or procedures agreed to by the Operating Committee, or Operating Committee agreements.

The following sections describe the processes and procedures used by the Operating Committee to develop the Treaty Storage Regulation studies. Although the Entities are jointly responsible for development of these studies, for greater clarity the text in this section specifies the various agencies that are currently responsible for providing the necessary inputs and running the necessary studies.

(1) Treaty Storage Regulation Input

Treaty Storage Regulation studies are prepared using a hydroregulation model to simulate the Columbia River system operation for power, flood control, and agreed-to non-power purposes. End-of-month storage contents for Canadian Treaty project reservoirs are determined from the results of the model simulation for the current operating year.

Data Requirements

Input data to a Treaty Storage Regulation study are either pre-defined or variable for a given operating year. Some input data for Treaty Storage Regulation studies are defined in the appropriate Assured Operating Plan final Step I Joint Optimum (-41) study. Assured Operating Plan inputs may be modified in the corresponding Detailed Operating Plan or by Operating Committee agreement. The hydroelectric operating plan includes pre-defined Treaty Storage Regulation inputs as follows:

Pre-defined Treaty Storage Regulation input data

- firm and secondary loads
- thermal and miscellaneous resources
- agreed-to non-power requirements
- other plant and operating data
- Assured Refill Curves
- Critical Rule Curves
- Operating Rule Curve Lower Limits
- end-of-July through end-of-November Upper Rule Curves

Inputs expected to vary each year are related to hydrological conditions in the Columbia River basin during the operating year. Details on preparing and coordinating variable input data to the Treaty Storage Regulation study are described in Section 4.4B of this document.

Variable Treaty Storage Regulation input data

- unregulated observed and forecast stream flow

- Variable Refill Curves
- end-of-December through end-of-June Upper Rule Curves
- hydro-independent generation

(2) Operational Treaty Storage Regulation studies

The Bonneville Power Administration obtains pre-defined input data to Treaty Storage Regulation studies, as described in Section 4.4A(1), from appropriate Assured Operating Plan and Detailed Operating Plan studies or from Operating Committee agreements.

The Bonneville Power Administration coordinates the collection of all variable input requirements to the model. Observed and forecasted stream flow data are retrieved from the Northwest Power Pool, who receives them from both individual project owners and the Bonneville Power Administration. Variable Refill Curves are collected from the various parties responsible for their development. Upper Rule Curves are provided by the U.S. Army Corps of Engineers.

The Bonneville Power Administration is responsible for running Treaty Storage Regulation studies, but both Entities will review input data and study results to assure consistency with the Detailed Operating Plan.

a) Treaty Storage Regulation Schedules

Under the direction of the Operating Committee, the Treaty Storage Regulation study is normally performed twice each calendar month. The first study is conducted within the first nine working days, while the second is run during the last eight working days of each month. At the request of either section of the Operating Committee, additional Treaty Storage Regulation studies shall be performed to reflect the most current unregulated stream flow forecasts and rule curves. The Operating Committee shall agree on procedures for preparing stream flow forecasts and rule curves at that time.

b) Time Periods of Treaty Storage Regulation studies

A Treaty Storage Regulation determines the end-of-month storage contents for a duration into the future that varies throughout the year. The end-of-month storage contents required for each Treaty Storage Regulation study can be determined from the following tables by looking at the stream flow data requirements for the Treaty Storage Regulation. As an example, the first Treaty Storage Regulation of the month in November, highlighted in the first table, confirms the end-of-October storage contents, and determines the end-of-November and end-of-December storage contents.

Table 10

Time Periods for Treaty Storage Regulation Studies

First Treaty Storage Regulation of the Calendar Month:

Storage contents for the end of period indicated →

TSR Date	Jul	Au1	Au2	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Ap1	Ap2	May	Jun	Jul	Au1	Au2
Au1	Obs	F/C	F/C	F/C													
Sep			Obs	F/C	F/C												
Oct				Obs	F/C	F/C											
Nov					Obs	F/C	F/C										
Dec						Obs	F/C	F/C									
Jan							Obs	F/C	F/C	F/C	F/C	F/C	F/C	F/C	F/C		
Feb								Obs	F/C	F/C	F/C	F/C	F/C	F/C	F/C		
Mar									Obs	F/C	F/C	F/C	F/C	F/C	F/C		
Ap1										Obs	F/C	F/C	F/C	F/C	F/C		
May												Obs	F/C	F/C	F/C		
Jun													Obs	F/C	F/C		
Jul														Obs	F/C	F/C	F/C

Second Treaty Storage Regulation of the Calendar Month:

Storage contents for the end of period indicated →

TSR Date	Au1	Au2	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Ap1	Ap2	May	Jun	Jul	Au1	Au2	Sep
Au2	Obs	F/C	F/C	F/C													
Sep			F/C	F/C	F/C												
Oct				F/C	F/C	F/C											
Nov					F/C	F/C	F/C										
Dec						F/C	F/C	F/C									
Jan							F/C	F/C	F/C	F/C	F/C	F/C	F/C	F/C			
Feb								F/C	F/C	F/C	F/C	F/C	F/C	F/C			
Mar									F/C	F/C	F/C	F/C	F/C	F/C			
Ap2										Obs	F/C	F/C	F/C	F/C			
May												F/C	F/C	F/C			
Jun													F/C	F/C	F/C	F/C	
Jul														F/C	F/C	F/C	F/C

Obs: Observed monthly stream flow

F/C: Forecasted monthly stream flow that may incorporate observed stream flow to the Treaty Storage Regulation date

c) Failure to Meet Load

If, as a result of low water conditions, the Treaty Storage Regulation shows deficits in any period, the storage operation, within the Treaty Storage Regulation study, of projects that fail to draft empty because of storage lower limits will be adjusted to utilize the maximum storage of the Base System in a manner consistent with the operation of those projects in the corresponding Assured Operating Plan. Projects that typically require adjustment include: Long Lake, Coeur d'Alene Lake, Albeni Falls, and Corra Linn.

The storage operation adjustments may require the following multi-step process to complete the Treaty Storage Regulation:

i) Note any deficits in the Treaty Storage Regulation, and identify any unused storage available to meet firm energy load carrying capability in the deficit period.

ii) For those projects that have unused storage capability because of storage lower limits, adjust the storage limits and/or remove specific target operations for the period of deficit as was done in the Assured Operating Plan. It may be necessary to over-ride the simulation model logic to accomplish this. Previous period results must not be altered.

iii) Set fixed operations for projects that were drafted further in Step ii above and re-run the Treaty Storage Regulation. Continue on proportional draft of the system through the end of the study so that the adjusted projects recover first; that is, keep the storage minimums for other periods.

4.4.B VARIABLE INPUTS TO TREATY STORAGE REGULATION STUDIES

The Operating Committee is responsible for coordinating stream flow and volume forecasts for Treaty purposes. The Committee has delegated the responsibility for developing forecast procedures and providing operational stream flow forecasts for Treaty projects to the Hydrometeorological Committee.

The Operating Committee is responsible for submitting observed stream flow, stream flow forecasts, and rule curves for all projects for the Treaty Storage Regulation. However, providing observed runoff, stream flow forecasts, and seasonal volume forecasts is a combined effort of numerous other agencies, including; the Bureau of Reclamation, the Northwest River Forecast Center, the Natural Resources Conservation Service, non-federal project owners, and the Northwest Power Pool.

Variable input data to Treaty Storage Regulation studies were identified in section 4.4.A.(1) of this document. The following sections describe these input requirements in more detail.

a) Observed Unregulated Stream flows

Observed unregulated stream flows used in the Treaty Storage Regulation are obtained from the Northwest River Forecast Center. BC Hydro verifies unregulated inflows to Mica, Arrow, and Duncan prior to use in the Treaty Storage Regulation study.

b) Volume Forecasts

Seasonal volume forecasts for various periods are required to compute Variable Refill Curves and Upper Rule Curves for Treaty Storage Regulation studies. The Operating Committee must first agree to any forecast procedure before the procedure is implemented into Treaty Storage Regulation studies. Either Section of the Operating Committee proposing to revise current forecast procedures for Treaty Storage Regulation purposes must provide the Operating Committee with adequate documentation and give the Committee sufficient time for review and comment. Due to the independent relationship of the NW River Forecast Center and the U.S. Bureau of Reclamation from the Treaty Entities, seasonal volume forecast procedures developed and revised by these agencies are considered agreed upon by the Operating Committee.

The Operating Committee has agreed to the following forecast procedures developed for use during the January-July season:

Sources for Seasonal Volume Forecasts agreed to by the Operating Committee

U.S. Army Corps of Engineers	**BC Hydro**	**U.S. Bureau of Reclamation**	**Natural Resources Conservation Service**	**Northwest River Forecast Center (Final Volume Forecasts)**
Dworshak (1) Libby (2)	Mica (3) Arrow (3) Duncan (3)	Hungry Horse (4)	The Willamette Projects (4)	All other required seasonal volume points, including Columbia River at The Dalles (4)

(1) Approved. 1995. Columbia River Water Management Group, Forecast Committee
(2) Approved. 1986. R. Wortman, U.S. Army Corps of Engineers
(3) Approved. 1997. "VOLCAST, Runoff volume forecast program for Canadian Columbia River International Treaty project reservoirs", W. Luo, BC Hydro
(4) Independent procedure

Adoption of new or revised forecast procedures will be documented in the Operating Committee meeting notes and annual reports.

The priority of seasonal volume forecasts used for Treaty Storage Regulation studies is as follows:

- Volume forecasts generated from seasonal volume forecast procedures agreed to by the Operating Committee;
- If the required volume forecasts are unavailable for any project, the default volume forecast becomes the median volumes for the 60-year period (1929-1988) from the 1990 Level Modified Flow Study (or its Operating Committee approved successor); and
- The Operating Committee may agree to override any default for a given Treaty Storage Regulation study

Should either Section of the Operating Committee wish to deviate from the results of agreed-to or default forecast procedures, then that Section will initiate a discussion with the other Section in order to gain agreement on the volumes to be used in the Treaty Storage Regulation.

c) *Monthly-Unregulated Streamflow Forecasts*

The responsibility for development of monthly-shaped, unregulated streamflow forecasts for the Treaty Storage Regulation is as follows:

U.S. Army Corps of Engineers	**Bonneville Power Administration**	**Northwest Power Pool and Non-Federal Project Owners**
Libby	Hungry Horse	Non-Federal projects
Dworshak	Grand Coulee	
Albeni Falls	Mica	
McNary	Arrow	
Lower Granite	Duncan	
John Day	Kootenay	
The Dalles	Kerr	
Bonneville	Brownlee	
Willamette projects		

Because median or historically based monthly distribution factors may not capture the hydrology of the current runoff shape, "best science" may dictate deviating from the default forecasts. Therefore, the monthly streamflow forecasts will be coordinated prior to each Treaty Storage Regulation study. The Bonneville Power Administration and the U.S. Army Corps of Engineers will coordinate their respective forecast points to preserve hydrologic consistency throughout the Columbia Basin system for each Treaty Storage Regulation study. The Bonneville Power Administration will also provide their forecasts for Mica, Arrow, and Duncan to BC Hydro for review and approval prior to each Treaty Storage Regulation study. During the January-through-June period, coordinating involves preserving the seasonal volume forecasts as well as the hydrologic consistency of all the forecast points. If a consensus cannot be reached for any of the forecast points, the default forecasts will be applied.

Default monthly stream flows are as follows:

- During the July-through-December period, the default flows are the median stream flows for the 60-year period (1929-1988) from the 1990 Level Modified Flow Study (or its Operating Committee approved successor).
- During the January-through-June period, the default stream flow forecast is the monthly distribution factors documented in the Assured Operating Plan and Detailed Operating Plan studies as applied to the seasonal volume forecasts.

The Operating Committee may agree to override any default for a given Treaty Storage Regulation study.

d) Rule Curves

Variable Refill Curves and Upper Rule Curves for submittals to January-through-June Treaty Storage Regulations are based on the appropriate seasonal volume forecasts agreed to by the Operating Committee. (See 4.4B(b))

Variable Refill Curves: The responsibility for computing the Variable Refill Curves for the first Treaty Storage Regulation of each month is as follows:

- BC Hydro computes the Variable Refill Curves for Canadian Projects. If the Operating Committee has agreed to use the Arrow Local method, Arrow Local Variable Refill Curves are also computed. Monthly shaping of the seasonal volume forecasts is based on the distribution factors documented in the Detailed Operating Plan.
- The U.S. Army Corps of Engineers computes Variable Refill Curves for Libby and Dworshak. Monthly shaping of seasonal volume forecasts is based on the distribution factors developed by the U.S. Army Corps of Engineers.
- The Bonneville Power Administration computes the Variable Refill Curves for Grand Coulee and Hungry Horse. Monthly shaping of the seasonal volume forecasts is based on the distribution factors developed by the Bureau of Reclamation.

Generally, Variable Refill Curves for the second Treaty Storage Regulation study each month are assumed to be the same as those computed for the first Treaty Storage Regulation study of the month. However, the Operating Committee may agree to deviate from the first of the month computations. If applicable, the Arrow local Variable Refill Curve is re-computed to reflect Mica’s new discharge from the Treaty Storage Regulation study.

Upper Rule Curves: The U.S. Army Corps of Engineers computes Upper Rule Curves for all projects based on the results of agreed-to seasonal volume forecast procedures for the first Treaty Storage Regulation of the month. The Upper Rule Curves used in the first Treaty Storage Regulation of the month are also used for the second Treaty Storage Regulation of the month, unless the seasonal volume forecasts were unavailable when the first of the month Upper Rule Curves were computed. In this event, the Upper Rule Curves will be recomputed using the latest available seasonal volume forecast for the second Treaty Storage Regulation of the month.

e) Hydro-independent generation

Hydro-independent generation is updated from the best available forecasts. Normally, this is provided from the Northwest Power Pool that either obtains data from the project owners or estimates generation as a percent of median based on stream flow forecasts for that or nearby basins. The U.S. Army Corps of Engineers provides stream flow and elevation forecasts and generation for the Willamette projects to the Northwest Power Pool.

4.4.C TREATY STORAGE REGULATION STUDY RESULTS

The Treaty Storage Regulation provides the Entities[11] with the required composite operation of Canadian Treaty Storage for the end of the current month and information on the subsequent two months to plan the near term operation of the system. Except for operations required in accordance with Section 4.4.E. (Operation for Flood Control), the Entities have agreed since 1967 to implement the indicated composite operation of Canadian Treaty Storage through weekly agreements on the required operation of Canadian Treaty Storage – the weekly Treaty Storage Operation Agreements. Unless otherwise agreed, the weekly Treaty Storage Operation Agreements are based on operating Canadian Treaty Storage to the end-of-month elevations determined in the current Treaty Storage Regulation study as modified by any Supplemental Operating Agreements (see Section 4.4.D of this document).

The Treaty Storage Regulation study results are distributed to U.S. and Canadian sections of the Operating Committee. The Operating Committee also submits the Treaty Storage Regulation month-end elevations for Canadian Treaty Storage to the Northwest Power Pool for input as a fixed operation to the Actual Energy Regulation[12] study, as outlined in Table 10.

4.4.D SUPPLEMENTAL OPERATING AGREEMENTS

The operation of Canadian Treaty Storage shall be guided by the Detailed Operating Plan and any Supplemental Operating Agreements[13] approved by the Entities during the operating year. Consistent with the operating principles, the Entities may agree to mutually beneficial arrangements for storage above and below the Treaty Storage Regulation levels to meet power and non-power objectives. In recent Detailed Operating Plans, the Entities have delegated the authority to implement such agreements to the Operating Committee. In this event, any agreed changes implemented by the Operating Committee, will be documented and reported back to the Entities.

The Supplemental Operating Agreements are generally designed to fine-tune the operation of Canadian Treaty Storage to address a number of power and non-power objectives as more information is obtained on the actual stream flows and operating conditions. When appropriate, the Entities will make suitable arrangements for delivery of power relating to any agreed sharing of power benefits from Supplemental Operating Agreements.

Examples of Supplemental Operating Agreements implemented in recent years include:

- **Arrow Lakes Local Method**: changes the method for determining the Variable Refill Curve for Arrow (see Appendix 5 for additional information on the Arrow Lakes Local Method). Improves the power operation of Arrow, consistent with the refill objectives at that project, whenever Mica's project operating criteria cause it to draft below its Variable Refill Curve;
- **Libby – Canadian Storage Exchange**: provides for exchange of storage between Libby and Canadian Treaty Storage to enhance power and environmental objectives;

[11] In practice, the Entities leave the day-to-day implementation of the Detailed Operating Plan to the Operating Committee.
[12] The Actual Energy Regulation is a computer hydro regulation study used by the Northwest Power Pool to determine U.S. project rights and obligations as defined by the Pacific Northwest Coordination Agreement
[13] Each Supplemental Operating Agreement can be considered a "detailed operating plan" in accordance with Article XIV(2)(k) of the Treaty. However, for greater clarity, the term Detailed Operating Plan is generally used to refer to the plan put in place at the start of the operating year and "Supplemental Operating Agreements" generally refers to those agreements implemented during the operating year.

- **Non-power Uses Agreement**: provides for smoothing of project operations to meet several objectives including trout spawning downstream of Arrow, salmon spawning at Vernita Bar, Arrow reservoir level enhancement for dust control and improved recreation, and flow augmentation for downstream migration of salmon;
- **Whitefish agreement**: provides January flow reductions to reduce impact of subsequent flow reductions on Whitefish spawning downstream of Arrow; and
- **Summer Treaty Storage Agreement**: provides for storage above the Treaty Storage Regulation to enhance U.S. system reliability and to provide various non-power benefits to Canadian Treaty Storage (implemented once in recent low flow (2001) conditions).

4.4.E OPERATION FOR FLOOD CONTROL

The regulation of Canadian Treaty Storage for system flood control may require that outflows be specified from individual projects on a daily basis. Such regulation shall be in accordance with the applicable Flood Control Operating Plan.

5 PROCEDURE FOR CALCULATING HYDROELECTRIC POWER LOSSES IN CANADA AS A RESULT OF OPERATING ON-CALL STORAGE

5.1 CONSIDERATIONS FOR ON-CALL STORAGE

The Treaty describes the obligation to provide “On-Call” flood control in Articles IV and VI and in Protocol I and II. The Flood Control Operating Plan (see reference at Section 1.3(4)) describes the procedure for implementing an on-call request in section 10-5 of that document.

In accordance with the Flood Control Operating Plan, consideration for the need for On-Call storage shall be initiated by the U.S. Section of the Operating Committee in consultation with the Canadian Section as soon as conditions indicate that use of On-Call storage may be necessary. Results of these considerations shall be reported to the respective Entities, together with the assessment of the effects of the drawdown on the production of power. A written request for On-Call storage space may be made by the U.S. Entity following the above consultation.

5.2 STUDIES REQUIRED UPON INITIATION OF ON-CALL REQUEST

Upon acceptance of a request for On-Call storage use by the U.S. Entity, the Operating Committee shall guide the preparation of a set of monthly system regulation studies for the period 1 January to 31 August or such later date that all Canadian Treaty Storage projects have recovered to where they would have been in absence of the On-Call evacuation. The purpose of the studies is to estimate the monthly outflows for Canadian Treaty Storage as if On-Call storage were not requested.

- The system regulation studies shall incorporate the rule curves, operating rules, etc., for Canadian Treaty Storage contained in the current Detailed Operating Plan and Supplemental Operating Agreements adjusted for current conditions, except that On-Call flood control storage shall not be included. The studies shall include all projects in Canada at-site or downstream from Canadian Treaty Storage, and all other Canadian projects coordinated in the Assured Operating Plan for applicable operating years.
- The studies will be updated at least monthly to reflect current forecasts and actual inflows for prior months.

If the On-Call storage request is accepted after 1 January, system studies shall be performed utilizing the most current conditions relating to initial reservoir elevations and outflows and the study period may be shortened accordingly.

The studies above shall be completed in a timely manner so that U.S. liabilities for capacity and energy may be computed as indicated in Section 5.3.

5.3 PROCEDURE FOR ESTIMATING POWER LOSSES

The Canadian Section of the Operating Committee shall perform the following daily calculations from the time that On-Call storage evacuation of Canadian Treaty Storage is initiated until all Canadian Treaty Storage projects have recovered to where they otherwise would have been in the absence of the On-Call evacuation (“the period of the On-Call request”).

(A) The energy and capacity without the On-Call request at all Canadian projects coordinated in the Assured Operating Plan for that period shall be calculated based on actual recorded inflows and the monthly outflows computed in the studies described in Section 5.2.

(B) The energy and capacity with the On-Call request at all Canadian projects coordinated in the Assured Operating Plan for that period, shall be computed as the sum of the actual daily energy and capacity at those projects.

Energy and capacity computations shall take into account the actual availability of generating units. The daily capacity loss (or gain) in Canada shall be computed on a daily basis by subtracting the capacity with the On-Call request from the capacity without the On-Call request. Similarly, the daily energy loss (or gain) in Canada shall be computed on a daily basis by subtracting the energy with the On-Call request from the energy without the On-Call request. Such daily energy differences will be accumulated throughout the period of the On-Call request.

If the volume runoff forecast at The Dalles changes significantly after initiation of the daily calculations, target and actual monthly outflows may be adjusted accordingly at the request of either Entity. Such adjustment shall consider Mica project at-site volume forecasts as well as Canadian system energy/capacity requirements.

5.4 DELIVERY OF CAPACITY AND ENERGY TO CANADA

At the initiation of an On-Call request, the Entities shall immediately develop detailed scheduling procedures to implement any required capacity and energy deliveries in accordance with the general principles described in Sections 5.4.A and 5.4.B below.

5.4.A CAPACITY DELIVERIES

If a capacity loss occurs based on the computations of Section 5.3 above, then daily capacity deliveries equal to the daily loss shall be made available by the U.S. Entity based on the need as stated by the Canadian Entity. If agreed to by both Entities, loss in capacity can be offset by gains in energy if energy is usable in the Canadian system.

5.4.B ENERGY DELIVERIES

It will normally not be possible to determine whether a net loss of energy has occurred until the end of the operating year, or until all Canadian Treaty Storage projects have recovered to where they otherwise would have been in the absence of the On-Call evacuation. Nevertheless, estimated energy deliveries shall be scheduled as agreed by the Entities, to compensate for any reduction in energy in Canada in the interim period.

5.5 LIABILITY OF UNITED STATES ENTITY

The procedure established in this Section 5.3 and 5.4 is intended as a practical means of estimating, measuring, and offsetting power losses in Canada which could reasonably be considered as a result of On-Call operation.

However, there remains the possibility that some combination of unforeseen circumstances, coupled with an operation of On-Call storage, could prevent the Canadian Treaty Storage from refilling during the current operating year. In that event, special procedures based on the particular circumstances may have to be instituted by the Entities to cover any losses not covered by the procedures outlined above.

The period of potential liability of the U.S. Entity to offset capacity and energy losses in Canada shall begin when On-Call storage evacuation begins, and shall end when the Canadian Treaty Storage recovers to where it otherwise would have been, unless the Entities otherwise agree.

6 CANADIAN ENTITLEMENT

Pursuant to Article V(2) and Article XIV(2)(j) of the Treaty, the Entities have agreed to detailed arrangements for delivery of the Canadian Entitlement to Canada or, alternatively, for disposal of all or portions of the Entitlement within the United States. The "Aspects Agreement" (see reference at Section 1.3(5)(e)) and the "Disposal Agreement" (see reference at Section 1.3(5)(d)) spell out the obligations on the Canadian and U.S. Entities. Although, for convenience, a number of these provisions are repeated below, the obligations on the Entities remain as indicated in the Aspects Agreement and the Disposal Agreement.

Under emergency conditions the operating personnel of the Entities are authorized to agree to deviate from the terms and conditions of this Section 6 during the period of the emergency. Each Entity will be responsible for any actions or authorizations necessary to implement such arrangements as may be required within their jurisdiction.

Notice provisions for scheduling to points of delivery in the U.S. are specified in the terms and conditions of the Disposal Agreement or may be specified in subsequent agreements made pursuant to the Disposal Agreement.

The Canadian and U.S. Entities agree to use reasonable efforts to alleviate any administrative difficulties created by scheduling under these guidelines.

6.1 INTERPRETATIONS

In this Section 6, the following terms shall have the indicated meanings:

"**Entitlement Delivery Amount**" shall mean that portion of the total Canadian Entitlement that is to be delivered to Canada, after consideration of any sales directly within the U.S. pursuant to the Terms of Sale or the Disposal Agreement, and adjusted for losses in accordance with Section 6.5;

"**Equal amounts each month**" will be interpreted as "constant average kilowatts" which means the amount of Canadian Entitlement energy for any given month is the average annual Canadian Entitlement energy pro rated based on the number of days in that month;

"**Points of Delivery**" shall mean the current points of delivery for the Canadian Entitlement, which, pursuant to the Aspects Agreement are:

- 3/14ths of the Entitlement Delivery Amount capacity is to be delivered to the Nelway Point of Delivery and the Waneta Point of Delivery (as defined in the Aspects Agreement); and
- 11/14ths of the Entitlement Delivery Amount capacity is to be delivered to the Blaine No. 1 Point of Delivery and the Blaine No. 2 Point of Delivery (as defined in the Aspects Agreement);

"**Month or months**", in this section only, shall mean calendar months; and

Use of the word "**scheduling**" in conjunction with "Canadian Entitlement" shall mean generation scheduling; use of the word "scheduling" with "transmission" shall mean transmission scheduling; and use of "scheduling" on its own shall mean both generation and transmission scheduling.

6.2 DELIVERY OF THE CANADIAN ENTITLEMENT

Subject to the Aspects Agreement, the U.S. Entity is required to deliver the Entitlement Delivery Amount to the Canadian Entity, and the Canadian Entity shall accept, the Entitlement Delivery Amount at those Points of Delivery as scheduled by the Canadian Entity. The U.S. will not impose any cost on Canada for such deliveries.

Alternatively, the Canadian Entity may elect to dispose of all or portions of Canadian Entitlement directly in the U.S. under the terms and conditions set forth in the Disposal Agreement. All transmission schedules to points other than those above must meet the requirements of the transmission provider that apply to all transmission customers at the time of the schedule.

Deliveries of the Entitlement shall not be interrupted or curtailed except for reasons of uncontrollable force or maintenance and then only on the same basis as deliveries of firm power from the Federal Columbia River Power System to Pacific Northwest customers of the Bonneville Power Administration or any successor. To the extent the Entities are unable to effect delivery of that part of the Entitlement that is to be delivered at Nelway/Waneta, the part not able to be so delivered shall be added to the amount to be delivered at Blaine. Notwithstanding the foregoing, the Entities agree that at any time, and from time to time, the portions of the Entitlement to be delivered to the respective Points of Delivery specified in the Aspects Agreement may be changed temporarily for operational reasons upon agreement by the Columbia River Treaty Operating Committee, representing the Entities.

6.3 ENTITLEMENT SCHEDULING

6.3.A DAILY PRE-SCHEDULING

The Canadian Entitlement is scheduled on a daily pre-scheduled basis. The Canadian Entity will use best efforts to schedule in each month all of the Canadian Entitlement energy for that month unless prevented from doing so by a forced outage or emergency conditions at B.C. transmission or generation facilities.

6.3.B SCHEDULING PROCEDURE

Prior to 1000 hours each Friday, or the last working day of the week if Friday is not a working day, the Canadian Entity will provide the U.S. Entity with an estimate (the "Initial Weekly Estimate") of the amount of Entitlement Delivery Amount energy that will be scheduled during the week commencing 2400 hours that day through 2400 hours the following Friday. Prior to 1000 hours each Monday, or the following working day if Monday is not a working day, the Canadian Entity will provide the U.S. Entity with a mid-week estimate (the "Mid-Week Estimate") of the Entitlement Delivery Amount energy that will be scheduled for the balance of the week commencing 2400 hours that day, added to the actual energy delivered or scheduled up to 2400 hours that day.

Prior to 1000 hours each Friday, or the last working day of the week if Friday is not a working day, the Canadian Entity will notify the U.S. Entity of the amount, if any, of available Entitlement Delivery Amount capacity that the Canadian Entity determines in good faith that it does not require during the following week, and the U.S. Entity will not, therefore, need to make available such Entitlement Delivery Amount capacity.

The Canadian Entity will each working day, on or before 0930 hours, provide the U.S. Entity with schedules specifying the hourly Entitlement Delivery Amount deliveries for the following day. If the following day is not a working day, the Canadian Entity will also provide the U.S. Entity with schedules for the day or days up to and including the next following working day.

The schedules may specify hourly deliveries of any amount up to the maximum set by the Entitlement Delivery Amount capacity. Unless otherwise agreed by the Entities' operating personnel, schedules provided pursuant to this Section 6.3.B will not be changed by the Canadian Entity, except as may be necessary or advisable due to outage or emergency conditions on the transmission system of an electric utility or other entity receiving deliveries of Canadian Entitlement.

The Entities acknowledge and agree that, except as may be agreed by the Entities' operating personnel:

1. total deliveries of Canadian Entitlement in any hour will not exceed the Entitlement Delivery Amount capacity;
2. Canadian Entitlement capacity is fully discharged when the U.S. Entity makes such capacity available, whether or not the Canadian Entity schedules hourly deliveries up to this capacity; and
3. to the extent that all of the Entitlement Delivery Amount energy in respect of any month is not or cannot be scheduled during that month by the Canadian Entity, then the undelivered energy will be scheduled by the U.S. Entity for return to the Nelway/Waneta and Blaine points of delivery. When the remaining energy to be delivered in any month exceeds the amount of energy that can be scheduled by full use of the capacity available to the Canadian Entity, the U.S. Entity may schedule delivery of excess energy to the Nelway/Waneta and Blaine points of delivery. The U.S. Entity will endeavor to schedule such energy during the month to the extent possible but may, at its option, schedule such energy up to 7 days into the subsequent month. In making such deliveries, the U.S. Entity will take reasonable account of constraints on the transmission and generation systems in B.C. accepting such energy.

Canadian Entitlement required to be delivered and not delivered due to uncontrollable force will be delivered within 7 days following the outage at times and rates determined by the Canadian Entity but limited by the Entitlement Delivery Amount capacity, unless otherwise agreed.

Canadian Entitlement required to be delivered to points other than the Points of Delivery, and not delivered due to uncontrollable force, may, at the option of the U.S. Entity, be delivered to the Points of Delivery if possible and subject to adjustments needed by the Canadian Entity in order to accept the energy that day due to system constraints.

Canadian Entitlement scheduled to be delivered to points other than the Points of Delivery, which cannot be delivered due to recall of non-firm transmission, or due to failure by British Columbia to schedule transmission which it was responsible for arranging, shall be deemed delivered.

6.4 SCHEDULE VARIATIONS

6.4.A DIFFERENCES BETWEEN THE INITIAL AND MID-WEEK ESTIMATES

If (a) the Mid-Week Estimate of the amount of Canadian Entitlement that will be scheduled for the week differs from the Initial Weekly Estimate by the equivalent of at least 28.3 cubic meters per second (1000 cubic feet per second) in weekly average flow in the Columbia River at the international boundary and (b) notwithstanding reasonable efforts the U.S. Entity determines it cannot accommodate the revised schedule within existing contractual and system operating constraints, then (c) the U.S. Entity may request a mid-week adjustment to the Treaty flow request equivalent to the difference between the Initial and Mid-Week Entitlement Estimates. For purposes of determining the flow equivalent to the difference between the Initial and Mid-Week estimates, the estimated weekly effective incremental total U.S. main stem Columbia generation/discharge factor will be used unless that value is below 60 megawatts per thousand cubic feet per second. If the generation/discharge factor is below 60 megawatts per thousand cubic feet per second, a generation/discharge factor of 60 megawatts per thousand cubic feet per second will be used. If the U.S. Entity determines an adjustment is needed, the U.S. Entity will notify the Canadian Entity by 1600 hours Monday (or, if Monday is not a working day, the next available working day) of the U.S. Entity's request for a mid-week adjustment. The Canadian Entity will at its option, either:

1. provide or accept an amount of energy equal to the difference between the Initial Weekly Estimate and the Mid-Week Estimate, or other mutually-agreed amount to be delivered Wednesday through Saturday; or
2. make a mid-week flow change for the period 0800 Tuesday through 0800 Saturday, equivalent to the difference between the Initial Weekly Estimate and the Mid-Week Estimate based on the estimated effective incremental total U.S. main stem generation versus generation/discharge factor for that period.

If a flow change is not made in accordance with 6.4.A(2) above, then energy deliveries in accordance with 6.4.A(1). above will be prescheduled by the delivering Entity on Tuesday for Wednesday through Saturday in accordance with normal preschedule procedures, unless adjustments are needed by the receiving Entity in order to accept the energy due to system constraints. Energy received will be returned during the following week on like hours, unless otherwise agreed. Each Entity will bear all costs of transmitting such energy in its own country.

EXAMPLE:	Mid-Week – Initial:	23,040 MWh
	Estimated US h/k:	57 MW/kcfs, therefore use minimum of 60
	Flow Equivalent:	23,040 / (60 x 7 days x 24 hours) = 2.3 kcfs
	Mid-Week Flow Option =	23,040 / (60 x 4days x 24 hours) = 4 kcfs
	Energy Delivery Option =	23,040 / (4 days x 24 hours) = 240 MW (BCH to BPA)

6.4.B DIFFERENCES BETWEEN THE ACTUAL SCHEDULE AND THE MID-WEEK ESTIMATE

If (a) the actual scheduled entitlement for the week differs from the Mid-Week Estimate by the energy equivalent of at least 28.3 cubic meters per second (1,000 cubic feet per second) in flow (weekly average in the Columbia River at the Canada – U.S. border) as determined using the estimated weekly effective incremental U.S. generation/discharge factor or an generation/discharge factor of 60 megawatts per thousand cubic feet per second, whichever is greater, and (b) notwithstanding reasonable efforts the U.S. Entity determines it cannot accommodate the revised schedule within existing contractual and system operating constraints, then (c) the U.S. Entity may request an adjustment equivalent to the difference between the Mid-Week Entitlement Estimate and the Actual Schedule.

If the U.S. Entity determines an adjustment is needed, the U.S. Entity will notify the Canadian Entity by 1600 hours Thursday of the U.S. Entity's request for an actual schedule adjustment. The Canadian Entity will at its option:

1. provide or accept an amount of energy equal to the difference between the Mid-Week Estimate and the Actual Schedule, or other mutually-agreed amount, to be delivered Saturday through Friday at a constant MW level over all hours unless otherwise agreed; or

2. make an adjustment to the weekly Treaty request for the following week 0800 Saturday through 0800 Saturday, equivalent to the difference between the Mid-Week Estimate and the Actual Schedule based on the maximum of the estimated weekly effective

incremental total US main stem generation/discharge factor (h/k) and an h/k of 60 MW/kcfs; or

3. follow any other adjustment method mutually agreed to by the US Entity and Canadian Entity;

If a flow change is not made in accordance with 6.4B(2) or 6.4.B (3), then energy deliveries under 6.4.B.(1) will be prescheduled by the delivering Entity on Friday for Saturday through Friday delivery in accordance with normal preschedule procedures, unless adjustments are needed by the receiving Entity in order to accept the energy due to system constraints. Energy received will be returned during the following week on like hours, unless otherwise agreed. Each Entity will bear all costs of transmitting such energy in its own country.

Example: Actual – Mid-Week: -28,560 MWh
Estimated US h/k: 85 MW/kcfs
Flow Equivalent = Treaty Flow Option = -28,560/(85 x 7days x 24 hours) = -2 kcfs
Energy Deliver Option = -28,560 / (7 days x 24 hours) = -170 MW (BPA to BCH)

6.4.C DIFFERENCES BETWEEN ACTUAL AND PRESCHEDULED DELIVERIES

If actual deliveries deviate from the prescheduled energy entitlement amounts, revised adjustments may be agreed to by the Entities.

6.5 LOSSES

Losses associated with Canadian Entitlement deliveries will be applied as follows:

- for deliveries of the Canadian Entitlement to the Points of Delivery the losses will be deducted at the time of delivery, and the resulting net Canadian Entitlement will be scheduled and delivered to the Points of Delivery;
- for deliveries of the Canadian Entitlement to points other than the Points of Delivery, the full amount scheduled will be delivered with losses being scheduled for return exactly 7 days later during the same hour as that during which the losses were incurred, or as otherwise agreed by the Entities.

During the period commencing on 1 April 1998 and ending on 15 September 2024 the transmission loss referred to in Article V(2)(a) of the Treaty, applicable to energy returned to the Canada-U.S. border, shall be calculated as 3.4% of the Canadian Entitlement energy from which first has been subtracted the amounts described in Article V(2)(b) (those amounts disposed of within the U.S. pursuant to the Disposal Agreement)[14].

Transmission losses applicable to Entitlement capacity deliveries to the Canada-U.S. border will be in accordance with the Bonneville Power Administration transmission loss tariff (currently 1.9%) or as established by the applicable transmission service provider.

Losses of power disposed of within the U.S. pursuant to the Disposal Agreement will have energy and capacity provisions as mutually agreed by the Entities (for disposals in the U.S. in accordance with Section 5 of the Disposal Agreement) or as established from time to time by

[14] As an historical note, for energy returned to the Canada-U.S. border, prior to 1 August 2003 (the Operating Year 2003-04 studies), an additional 0.2% of the Canadian Entitlement was also subtracted. This 0.2% adjustment is applied to reflect the fact that step-up transformation from federal generators to the U.S. federal transmission system were not included in the plant data used in the Determination of Downstream Power Benefits prior to the 2003-04 studies, as previously discussed in Section 3.3.A(1).

the applicable transmission service provider (for disposals in the U.S. in accordance with Section 4 of the Disposal Agreement).

APPENDIX 1 –REFILL CURVES

Procedures For Determining Assured Refill Curves and Variable Refill Curves that Optimize Power Generation

1. **Assured Refill Curves:** Initialize Assured Refill Curves at levels that optimally meet firm load during the refill period, and that pass the Refill Test (as described in Section 2.3.B(3)) when only these Assured Refill Curves are incorporated into the study (i.e. Variable Refill Curves are not included).
   a) Use the critical period optimizer to determine an optimum power operation for each storage project that meets the firm energy load carrying capability and refills, during January-July 1931. Firm loads in the fall may be raised or lowered to enable the system to meet firm load in January-July.
   b) Determine the end of the drawdown period for each project as the period with the lowest content during January-June, from the optimizer study. For the periods after the end of the drawdown period, the Assured Refill Curve shall be the contents from the optimizer study. During the drawdown periods, the Assured Refill Curve is determined using a minimum flow discharge requirement and upstream refill requirements, working backward from the first Assured Refill Curve period after the end of the drawdown periods.
   c) Perform a Refill Study, incorporating the trial Assured Refill Curve, but excluding Variable Refill Curves, to determine if the trial Assured Refill Curve needs to be adjusted upward to pass the Refill Test. The Refill Study uses PNCA procedures, except that Variable Refill Curves are not included and changes to projects that refill (e.g. Grand Coulee) may be required if it improves refill at other projects.
2. **Variable Refill Curve:** The Variable Refill Curve is developed in the manner outlined in Section 2.3.B(2) of this document, except that a Lower Limit is developed for the Variable Refill Curve at the three different volume runoff levels corresponding to the Power Discharge Requirement levels. Specifically:
   a) Use the critical period optimizer to determine three optimum power operations that meet non-power constraints and refill at the 98.68 cubic kilometer, 117.18 cubic kilometer, and 135.68 cubic kilometer (80, 95, and 110 million acre-foot, respectively) levels. Use 1940 flows for 98.68 cubic kilometers (80 million acre-foot), 1955 for 117.18 cubic kilometer (95 million acre-foot), and 1946 for the 135.68 cubic kilometer (110 million acre-foot) level. (These flow years were chosen as representative of flow volumes and distributions for flows at The Dalles of the indicated volume.) Optimum power objectives are:
      i) Meet firm energy load carrying capability during January-July. Firm load may be lowered or raised in the fall to enable the system to meet these objectives.
      ii) Minimize May-July secondary energy by drafting as low as possible by April 30th.
      iii) Subject to i) and ii), maximize January-July secondary energy.
   b) Crossovers between the indicated Lower Limit for the 98.68 cubic kilometer, 117.18 cubic kilometer, and 135.68 cubic kilometer (80, 95, and 110 million acre-foot, respectively) level optimum power operations and the greater of the Assured Refill Curve and the first year Critical Rule Curve will be eliminated by lowering the

135.68 cubic kilometer (110 million acre-foot) level to the 117.18 cubic kilometer (95 million-acre-foot) level, the 117.18 cubic kilometer (95 million acre-foot) level to the 98.68 cubic kilometer (80 million acre-foot) level, and lowering the 98.68 cubic kilometer (80 million acre-foot) level to the greater of the Assured Refill Curve and the first year Critical Rule Curve. Eliminate crossovers between the first-year rule curve and Variable Refill Curve Lower Limits as needed to allow duplication of the critical period, by raising the Variable Refill Curve Lower Limits (generally for 98.68 cubic kilometers (80 million-acre-feet) at Grand Coulee only) to the Critical Rule Curve 1 (or the higher of Critical Rule Curve 1, 2, or 3).

c) Use the 98.68 cubic kilometers (80 million acre-feet) January-July optimum power/refill operation as a Variable Refill Curve Lower Limit during periods when the January-July volume runoff at The Dalles is less than or equal to 98.68 cubic kilometers (80 million acre-feet). Similarly, use the 135.68 cubic kilometers (110 million acre-feet) optimum power/refill operation for years when the forecast is greater than or equal to 135.68 cubic kilometers (110 million acre-feet), and interpolate between 80-95 or 95-110 for years when the forecast is between 98.68 and 135.68 cubic kilometers (80 and 110 million acre-feet).

d) Include the Assured Refill Curve and January-June Variable Refill Curve Lower Limits in the computation of Variable Refill Curves for the Refill Study. Variable Refill Curve Lower Limits apply only to individual months and do not require raising prior months by the same amount.

3. **Refill Study**: If Variable Refill Curves at all projects that fail to refill are raised to their Assured Refill Curve, and the Refill Test is not satisfied, it may be necessary to raise the Assured Refill Curve and/or Variable Refill Curves further to pass the Refill Test. For example, in the Assured Operating Plan for 2005/06, when the respective Variable Rule Curve was lower than the first year Critical Rule Curve, the 98.68 cubic kilometers (80 million acre-feet) Variable Refill Curve Lower Limits were raised to the first year Critical Rule Curve for that project and period[15]. Once these adjustments were made, the refill test was repeated and adjustments made to the Assured Refill Curves, Variable Refill Curves and Power Discharge Requirements as necessary. No changes were made to the computation or use of Operating Rule Curve Lower Limits.

[15] After checking all projects in the 2006 AOP studies, the only adjustment was Grand Coulee in the Step I study.

APPENDIX 2 - NON-POWER REQUIREMENTS AND ADDITIONAL PROJECT OPERATING PROCEDURES

Project Non-Power Requirements

Project non-power requirements that have been adopted for use in Treaty studies are provided in the table contained in this Appendix 2. These tables make reference to the following abbreviations:

AOPnn	Assured Operating Plan for year “nn”
Apr	April 1 through April 30
Apr 15	April 1 through April 15
Apr 30	April 16 through April 30
Aug	August 1 through August 31
Aug 15	August 1 through August 15
Aug 31	August 16 through August 31
BECC	Base Energy Content Curve (Higher of Critical Rule Curve and Assured Refill Curve)
cfs	Cubic feet per second
CP	Critical period
CRTOC	Columbia River Treaty Operating Committee
FERC	Federal Energy Regulatory Commission
ft	Feet
hm^3	Cubic hectometers
IJC	International Joint Commission
IPC	Idaho Power Company
ksfd	Thousands of cubic feet per second days of content (not space)
LT	Long-term study (30-year study)
m	Meters
m^3/s	Cubic Meters per second
MOP	Minimum operating pool elevation
MPC	Montana Power Company
PDP	Proportional Draft Point
PNCA	Pacific Northwest Coordination Agreement
TSR	Treaty Storage Regulation
SMIN	Minimum storage content
URC	Upper rule curve

The notes below provide additional clarification for the correspondingly numbered items referenced in the tables:

1) Not a change from the studies run in 1996, but newly listed from the 29 August 1996 Entity Agreement.
2) Data new since the 29 August 1996 Entity Agreement.
3) Data correction.
4) Non-Base System projects (except Libby) should be updated every year to the best estimate of expected operation.

Project Operating Procedures for the 2005-06 Assured Operating Plan and Determination of Downstream Power Benefits

Project		Applicable Period	Requirements				Elevation Equivalent		
	Constraint Type	or other explanation	English		Metric		Feet	Meters	Source/Comments
Canadian Projects									
Mica									
	Minimum Flow		3000	cfs	84.95	m^3/s			In place in AOP79, AOP80, AOP84
Arrow									
	Minimum Flow		5000	cfs	141.59	m^3/s			In place in AOP79, AOP80, AOP84
	Draft Limit		1	ft/day	0.30	m/day			
Duncan									
	Minimum Flow		100	cfs	2.83	m^3/s			In place in AOP79, AOP80, AOP84
	Maximum Flow		10000	cfs	283.18	m^3/s			
	Draft Limit		1	ft/day	0.30	m/day			
	Other	Operate to meet IJC orders for Corra Linn							CRTOC agreement on procedures to implement 1938 IJC order
Base System									
Hungry Horse									
	Minimum Flow	Minimum project discharge	400	cfs	11.33	m^3/s			In place in AOP79, AOP80, AOP84
	Maximum Flow	None							
	Minimum Content	None							
	Other	No VECC limit							VECC limit not in place in AOP79
Kerr									
	Minimum Flow	All periods	1500	cfs	42.48	m^3/s			In place in AOP80, AOP84
	Maximum Flow	None							
	Minimum Content	Jun - Sep	614.7	ksfd	1504.0	hm^3	2893.0	881.80	MPC 2-1-92, PNCA submittal. Similar operation, Jun-Aug 15, in AOP80
		May	426.3	ksfd	1043.0	hm^3	2890.0	880.88	
		Empty Apr 15	0.0	ksfd	0.0	hm^3	2883.0	878.75	FERC, AOP80
	Maximum Content [1]	March (Included to help meet the Apr 15 FERC requirement.)	58.6	ksfd	143.4	hm^3	2884.0	879.05	In place in AOP80 and AOP84
	Other	Conditions permitted, should be on or about, empty Mar and Apr 15.	0.0	ksfd	0.0	hm^3	2883.0	878.75	FERC, AOP80
Thompson Falls									
	None Noted								

Project Operating Procedures for the 2005-06 Assured Operating Plan and Determination of Downstream Power Benefits

Project	Constraint Type	Applicable Period or other explanation	Requirements English		Requirements Metric		Elevation Equivalent Feet	Elevation Equivalent Meters	Source/Comments
Noxon Rapids									
	Minimum Content								
	For Step I:	May - Aug 31,	116.3	ksfd	284.6	hm^3	2331.0	710.50	In place in AOP84,
		Sep - Jan,	112.3	ksfd	274.8	hm^3	2330.0	710.19	similar operation in
		Feb,	78.7	ksfd	192.6	hm^3	2321.0	707.45	AOP80
		Mar,	26.5	ksfd	64.8	hm^3	2305.0	702.57	
		Empty Apr 15, Apr 30, and end of CP.	0.0	ksfd	0.0	hm^3	2295.0	699.52	
	Minimum & Maximum Content								
	For Steps II & III:	All periods	116.3	ksfd	284.6	hm^3	2331.0	710.50	In place in AOP79, AOP84
Cabinet Gorge									
	None Noted								
Albeni Falls									
	Minimum Flow	All periods	4000	cfs	113.27	m^3/s			In place in AOP80, AOP84
	Minimum Content		(Dec may fill on restriction, note below)						
		Jun - Aug 31	582.4	ksfd	1425.0	hm^3	2062.5	628.66	In place in AOP80,
		Sep	465.7	ksfd	1139.4	hm^3	2060.0	627.90	AOP84
		Oct	190.4	ksfd	465.8	hm^3	2054.0	626.07	
		Nov-Apr 15	57.6	ksfd	140.9	hm^3	2051.0	625.15	
		Apr 30 (empty at end of CP)	190.4	ksfd	465.8	hm^3	2054.0	626.07	
		May	279.0	ksfd	682.6	hm^3	2056.0	626.68	
	For Steps I & II: [1]		Optimum to run CP & LT to Jun-Oct SMINs.						
	For Step III: [1]		Keep full at beginning of CP. Often (not always) optimum to run higher than SMIN in CP & LT						
			(except when occasionally drafting below SMIN to meet load).						
		Nov - Mar	57.6	ksfd	140.9	hm^3	2051.0	625.15	
		May	458.4	ksfd	1121.6	hm^3	2059.8	627.83	
		Sep	582.4	ksfd	1425.0	hm^3	2062.5	628.66	
		Oct	465.7	ksfd	1139.4	hm^3	2060.0	627.90	
	Kokanee Spawning		Draft no more than 1 ft below Nov 20 elevation through Dec 31.						In place before AOP80 and supported by minimum contents noted above.
			If project fills, draft no more than 0.5 ft.						
			Dec 31 - Mar 31 operate between SMIN and URC within above noted draft limits.						
	Other Spill	All periods	50	cfs	1.42	m^3/s			
Box Canyon									
	None Noted								

Project Operating Procedures for the 2005-06 Assured Operating Plan and Determination of Downstream Power Benefits

Project	Constraint Type	Applicable Period or other explanation	Requirements English		Requirements Metric		Elevation Equivalent Feet	Elevation Equivalent Meters	Source/Comments
Grand Coulee									
	Minimum Flow	All periods	30000	cfs	849.55	m^3/s			In place in AOP79, AOP80, AOP84
	Minimum Content								
		Empty at end of CP	0.0	ksfd	0.0	hm^3	1208.0	368.20	
	Step I only:	May and June	843.9	ksfd	2064.8	hm^3	1240.0	377.96	Retain as a power operation (for pumping)
	Steps II & III only: [1]	May and June	857.9	ksfd	2099.0	hm^3	1240.0	377.96	
	Maximum Content	Operating Room							
	Step I only:	Sep					1288.0	0.61	In place in AOP89. Retain as a power operation
		Dec-Feb					1287.0	0.91	
	Steps II & III:	Aug-Nov	2557.1	ksfd	6256.4	hm^3	1288.0	392.59	
	[1]	Dec-Feb	2518.3	ksfd	6161.5	hm^3	1287.0	392.28	
	Draft Rate Limit	(bank sloughage)	1.3	ft/day	0.40	m/day			
			1.5	ft/day	0.46	m/day			Constraint submitted as 1.5 ft/day interpreted as a monthly average of 1.3 ft/day
Chief Joseph									
	Other Spill	All periods	500	cfs					
Wells									
	Other Spill	All periods	1200	cfs					With fish ladder
	Fish Spill	Removed							
Rocky Reach									
	Fish Bypass								Bypass not modeled.
	Fish Spill	Removed							
	Other Spill [3]	Aug 16 - Apr 15 (leakage)	200	cfs	5.66364	m^3/s			
Rock Island									
	Fish Bypass	Bypass not modeled (installation date set to year 2010 in input file).							
	Fish Spill	Removed							
Wanapum									
	Fish Bypass								Bypass not modeled.
	Fish Spill	Removed							
	Other Spill	All periods	2200	cfs	62.3	m^3/s			With fish ladder

Project Operating Procedures for the 2005-06
Assured Operating Plan and Determination of Downstream Power Benefits

Project	Constraint Type	Applicable Period or other explanation	Requirements English		Requirements Metric		Elevation Equivalent Feet	Elevation Equivalent Meters	Source/Comments
Priest Rapids									
	Minimum Flow	Limit removed							
	Fish Bypass								Bypass not modeled.
	Fish Spill	Removed							
	Other Spill	All periods	2200	cfs	62.3	m^3/s			With fish ladder
Brownlee									
	Minimum Flow	All periods	5000	cfs	141.591	m^3/s			In place in AOP79, AOP80, AOP84
	Power Operation	Agree to use “old” power operation (fixed operation) provided by IPC and used in AOP since AOP97 for CP.							2-1-91 PNCA submittal
	[2]	LT run to PDP using rule curves from CP with BECC created from regulation spreadsheet to meet flow requirements at Lime Pt., and Brownlee and mimic the "old" historic fixed operation on a 60 year average and median comparison. Consistent with TSR.							7-00 See Special Operating Procedures #1 following this table.
Oxbow									
	Other Spill	All periods	100	cfs	2.83	m^3/s			
Ice Harbor									
	Minimum Flow	None							
	Fish Bypass								Bypass not modeled.
	Other Spill	All periods	740	cfs	20.96	m^3/s			
	Incremental Spill	None							
	Fish Spill	None							
	Other	Run at all periods	204.8	ksfd	501.1	hm^3	440.0	134.11	
McNary									
	Other Spill	All periods	3475	cfs	98.41	m^3/s			
	Incremental Spill	None							
John Day									
	Minimum Flow	Mar - Nov	50000	cfs	1415.91	m^3/s			
		Dec - Feb	12500	cfs	353.98	m^3/s			
	Fish Bypass								Bypass not modeled.
	Fish Spill	Removed							
	Incremental Spill	None							
	Other Spill	All periods	800	cfs	22.65	m^3/s			
	Other								
	Step I: [2]	June - Aug 15	269.7	ksfd	659.9	hm^3	268.0	81.69	In place AOP80
		Aug 31 - Sep	242.5	ksfd	593.3	hm^3	267.0	81.38	
		Oct - Mar	153.7	ksfd	376.1	hm^3	263.6	80.35	
		Apr 15 - May	114.9	ksfd	281.1	hm^3	262.0	79.86	
	Steps II & III:	Use John Day as run-of-river plant.	190.0	ksfd	265.0	ft			

Project Operating Procedures for the 2005-06 Assured Operating Plan and Determination of Downstream Power Benefits

Project		Applicable Period	Requirements				Elevation Equivalent		
	Constraint Type	or other explanation	English		Metric		Feet	Meters	Source/Comments
The Dalles									
	Minimum Flow	Mar - Nov	50000	cfs	1415.91	m^3/s			
		Dec - Feb	12500	cfs	353.98	m^3/s			
	Fish Bypass								Bypass not modeled.
	Fish Spill	Removed							
	Incremental Spill	None							
	Other Spill	All periods	1300	cfs	36.81	m^3/s			
Bonneville									
	Fish Bypass								Bypass not modeled.
	Fish Spill	Removed							
	Incremental Spill	None							
	Other Spill	All periods	8040	cfs	227.68	m^3/s			
Corra Linn (Kootenay Lake)									
	Minimum Flow	All periods	5000	cfs	141.59	m^3/s			BC Hydro agreements 1969
	Other	Operate to IJC orders.							CRTOC agreement on procedures to implement 1938 IJC order
Chelan									
	Minimum Flow	All periods	50	cfs	1.42	m^3/s			In place in AOP79, AOP80, AOP84
	Minimum Content	Jul - Sep (except as needed to empty at end of critical period).	308.5	ksfd	754.8	Hm^3	1098.0	334.67	In place in AOP79, AOP80, AOP84
Couer d'Alene Lake									
	Minimum Flow	All periods	50	cfs	1.42	m^3/s			
	Minimum Content	May - Aug	112.5	ksfd	275.3	Hm^3	2128.0	648.62	In place in AOP79
Post Falls									
	Minimum Flow	All periods	50	cfs	1.42	m^3/s			In place in AOP79,
									AOP80, AOP84

Project Operating Procedures for the 2005-06 Assured Operating Plan and Determination of Downstream Power Benefits

Project	Constraint Type	Applicable Period or other explanation	Requirements English		Requirements Metric		Elevation Equivalent Feet	Elevation Equivalent Meters	Source/Comments

Other Major Step I Projects [4]

Project	Constraint Type	Applicable Period or other explanation	English		Metric		Feet	Meters	Source/Comments
Libby									
	Minimum Flow	All periods	4000	cfs	113.27	m^3/s			
	Other Spill	All periods	200	cfs	5.66	m^3/s			
	Minimum Content		By contract year: Aug-Jul i.e., 1929 = Aug 1928 - Jul 1929						
		1929 Dec	776.9	ksfd	1900.8	hm^3	2363.0	720.25	2-1-93 PNCA
		1929 Jan	676.5	ksfd	1655.2	hm^3	2355.0	717.81	submittal, in place
		1929 Feb	603.6	ksfd	1476.8	hm^3	2349.0	715.98	in AOP99
		1929 Jul	2147.7	ksfd	5254.8	hm^3	2443.0	744.64	
		1930 Dec	652.0	ksfd	1595.2	hm^3	2353.0	717.20	
		1930 Jan	433.2	ksfd	1059.9	hm^3	2334.0	711.41	
		1930 Feb	389.3	ksfd	952.5	hm^3	2330.0	710.19	
		1930 Mar	348.5	ksfd	852.7	hm^3	2326.0	708.97	
		1930 Apr 15	297.4	ksfd	727.6	hm^3	2321.0	707.45	
		1930 Apr 30	444.2	ksfd	1086.8	hm^3	2335.0	711.72	
		1930 May	499.1	ksfd	1221.1	hm^3	2340.0	713.24	
		1930 Jun	1344.6	ksfd	3289.8	hm^3	2402.0	732.14	
		1930 Jul	1771.9	ksfd	4335.3	hm^3	2425.0	739.15	
		1931 Dec	317.8	ksfd	777.6	hm^3	2323.0	708.06	
		1931 Jan	192.2	ksfd	470.3	hm^3	2310.0	704.10	
		1931 Feb-Apr 30	103.1	ksfd	252.3	hm^3	2300.0	701.05	
		1931 May	192.2	ksfd	470.3	hm^3	2310.0	704.10	
		1931 Jun	676.5	ksfd	1655.2	hm^3	2355.0	717.81	
		1931 Jul	868.0	ksfd	2123.7	hm^3	2370.0	722.38	
		1932 Dec	174.4	ksfd	426.7	hm^3	2308.0	703.49	
		1932 Jan	103.1	ksfd	252.3	hm^3	2300.0	701.05	
		Empty at end of CP***	0.0	ksfd	0.0	hm^3	2287.0	697.09	
		All Dec	776.9	ksfd	1900.8	hm^3	2363.0	720.25	
			July 1930 - No more than 373.1 ksfd lower than July 1929						2-1-94 PNCA
			July 1931 - No more than 857.1 ksfd lower than July 1930						submittal, in place
			March - Implement PNCA 6(c)2(c).						in AOP00 and
									AOP01
	Maximum Summer Draft		5	ft	1.5240	m			
	Other	Operate to meet IJC orders for Corra Linn							CRTOC agreement on procedures to implement 1938 IJC order

Project Operating Procedures for the 2005-06
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Project		Applicable Period	Requirements				Elevation Equivalent		
	Constraint Type	or other explanation	English		Metric		Feet	Meters	Source/Comments
Dworshak									
	Minimum Flow	All periods	1300	cfs	36.81	m^3/s			2-1-99 PNCA submittal
	Maximum Flow	Apr 15 - Aug31	14000	cfs	396.45	m^3/s			2-1-99 PNCA submittal
		(Model requirement includes Maximum flow for all periods but URC generally overrides.)							
		Maximum release for flood control all periods.	25000	cfs	707.95	m^3/s			
	Minimum Content	SMIN Apr 15 - Aug 31	395.8	ksfd	968.4	hm^3	1520.0	463.30	
	Start 3 yr CP at:	Aug 15	395.8	ksfd	968.4	hm^3	1520.0	463.30	
	End 3 yr CP at:	Feb	218.4	ksfd	534.4	hm^3	1490.2	454.22	
	Other	Run on minimum flow or flood control observing maximum & minimum flow requirements all periods except to meet Lower Granite Target flows (based on sliding scale below):							2-1-99 PNCA submittal
	Lower Granite Target Flow		**Lower Bound**		**Upper Bound**				
			cfs	m^3/s	cfs	m^3/s			
		Apr 15	75200	2129.5	88200	2497.7			Refill Studies [(2x11500)+(13x100000)]/15
		Apr 15	75200	2129.5	93333	2643.0			Long Term Studies [(2x50000)+(13x100000)]/15
		Apr 30 - May 30	85000	2407.0	100000	2831.8			
		Jun 30	73333	2076.7	85000	2407.0			
		Jul - Aug 31	50000	1415.9	55000	1557.5			
	Other Spill	All periods	100	cfs	2.83	m^3/s			
Lower Granite									
	Minimum Flow	Mar-Nov	11500	cfs	325.66	m^3/s			
	Fish Spill	(only if regulated flow $\geq$ 85000 cfs)							2-1-99 PNCA submittal
		Apr 15 [22500*13/15]	19500	cfs	552.20	m^3/s			
		Apr 30 & May	22500	cfs	637.16	m^3/s			
		Jun [22500*20/30]	15000	cfs	424.77	m^3/s			
	Maximum Fish Spill		22500	cfs	637.16	m^3/s			
	Incremental Spill	Removed							
	Other Spill	All periods	670	cfs	18.97	m^3/s			
	Other	On MOP Apr 15 - Oct 31.	224.9	ksfd	550.3	hm^3	733	223.42	
		On full pool Nov 30 - Mar 31.	245.8	ksfd	601.4	hm^3	738	224.95	

Project Operating Procedures for the 2005-06
Assured Operating Plan and Determination of Downstream Power Benefits

Project	Constraint Type	Applicable Period or other explanation	Requirements English		Requirements Metric		Elevation Equivalent Feet	Elevation Equivalent Meters	Source/Comments
Little Goose									
	Minimum Flow	Mar - Nov	11500	cfs	325.66	m^3/s			
	Bypass Date	None							
	Fish Spill	(only if regulated flow at Lower Granite ≥ 85000 cfs)							2-1-99 PNCA submittal
		Apr 15 [30000*13/15]	26000	cfs	736.27	m^3/s			
		Apr 30 & May	30000	cfs	849.55	m^3/s			
		Jun [30000*20/30]	20000	cfs	566.36	m^3/s			
	Maximum Fish Spill		30000	cfs	849.55	m^3/s			
	Incremental Spill	Removed							
	Other Spill	All periods	630	cfs	17.84	m^3/s			
	Other	On MOP Apr 15 - Aug 31.	260.5	ksfd	637.4	hm^3	633.0	192.94	
		On full pool Sep 30 - Mar 31.	285.0	ksfd	697.3	hm^3	638.0	194.46	
Lower Monumental									
	Minimum Flow	Mar-Nov	11500	cfs	325.66	m^3/s			
	Bypass Date								A bypass date of 2010 was assumed
	Fish Spill	(only if regulated flow at Lower Granite ≥ 85000 cfs)							2-1-99 PNCA submittal
		Apr 15 [20000*13/15]	17333	cfs	490.84	m^3/s			
		Apr 30 & May	20000	cfs	566.36	m^3/s			
		Jun [20000*20/30]	13333	cfs	377.57	m^3/s			
	Maximum Fish Spill		20000	cfs	566.36	m^3/s			
	Other Spill	All periods	750	cfs	21.24	m^3/s			
	Other	On MOP Apr 15 - Aug 31.	180.5	ksfd	441.6	hm^3	537.0	163.68	
		On full pool Sep 30 - Mar 31.	190.1	ksfd	465.1	hm^3	540.0	164.59	
Cushman									
	Other Spill	All periods	100	cfs	2.83	m^3/s			
LaGrande									
	Other Spill	All periods	30	cfs	0.85	m^3/s			
White River									
	Other Spill	All periods	130	cfs	3.68	m^3/s			
Round Butte									
	Other Spill	All periods	200	cfs	5.66	m^3/s			
	Minimum Content	All periods	118.7	ksfd					2-1-99 PNCA submittal

ADDITIONAL PROJECT OPERATING PROCEDURES

1. Brownlee

Unlike all other U.S. Base System projects, Brownlee's power operation is not influenced by the Pacific Northwest Coordination Agreement operating procedures that provide guidance for a system-wide optimum power generation. Instead, the project is operated by Idaho Power Company (IPC) to meet non-power requirements and IPC loads. Prior to the 2005-06 Assured Operating Plan (AOP), AOP hydroregulation studies included a fixed 50 or 60-year operation based on operating criteria provided by IPC in 1986, except that Brownlee was drafted empty at the end of the critical period, and, for Step II/III studies the project was filled prior to the start of the critical period.

Beginning with the 2005-06 Assured Operating Plan, critical rule curves, operating rule curves, and non-power requirements were used to guide the operation of Brownlee in a manner similar to all other U.S. Base System projects. The reason for the change in operating procedures was to assure consistency between the AOP and the Detailed Operating Plan (DOP) Treaty Storage Regulation (TSR) study, since an IPC operation with 1986 procedures is not available for the TSR. The Project minimum outflows were 6,500 cfs during July through September and 5,850 cfs during October through June, except when higher minimum outflows were needed to assure 13,000 cfs downstream at Lime Point. The Critical Rule Curves were set equal to the IPC fixed operation during the critical period, and the Assured and Variable Refill Curves were set by trial-and-error to levels that result in a storage operation that minimizes deviations from the 60-year fixed operation. The same Variable Refill Curve is used for every year.

2. Corra Linn (Kootenay Lake)

The International Joint Commission (IJC) procedures that limit the operation of Kootenay Lake cannot be directly implemented in the monthly hydroregulation models used for AOP and DOP studies. This is because the IJC procedures require parallel studies based on maximum flow capabilities prior to the deepening of the outlet channel. The following procedures are used in AOP and DOP related hydroregulation studies, and are designed to produce an operation that approximately follows the IJC requirements.

a). Target Kootenay Lake elevation/storage operation, for every year, regardless of water condition, to the following end-of-month storage/elevation levels, subject to the limits in paragraphs b) and c) below. All Critical Rule Curves and the Operating Rule Curve are set to the following levels regardless of the actual critical period operation.

Month-end for:	Elevation		Storage Content	
	Feet	Meters	ksfd	hm^3
Sept. through December	1745.32	531.97	396.9	971.1
January	1744.0	531.57	322.8	789.8
February	1742.4	531.08	234.8	574.5
March, April 15 & 30	1739.32	530.14	69.8	170.8
May through August	1743.32	531.36	285.4	698.3

b) Kootenay Lake operation to the above target contents is limited to a 141.58 cubic meters per second (5 thousand cubic feet per second) minimum outflow and a maximum outflow determined by the channel outlet restriction. The maximum flow always controls in May, usually in April 15-30 and June, sometimes in February, March, April 1-15, and July, and rarely other months. Some maximum channel outlet capabilities are:

Elevation		Maximum capability	
feet	Meters	Thousand Cubic Feet per Second	Cubic Meters per Second
1739.30	530.14	18.69	529.2
1743.30	531.36	36.41	1031.0
1745.30	531.97	46.26	1309.9
1748.00	532.79	61.65	1745.7

c) During all months, reduce Libby and Duncan outflows to the extent that their combined outflow in excess of inflow (i.e. net draft) causes Kootenay Lake to exceed the above Target Contents because of channel outlet restriction. Allocate the reduction first to Duncan, limited to 28.3 cubic meters per second (1 thousand cubic feet per second) minimum flow, then Libby to 113.3 cubic meters per second (4 thousand cubic feet per second), then Duncan to 2.8 cubic meters per second (100 cubic feet per second), all limited to flood control. If Kootenay Lake is still above the target elevation, then reduce any Duncan plus Libby outflows greater than natural flow by first violating flood control at Libby subject to local minimum flow and then violating flood control at Duncan subject to local minimum flow. If these procedures are implemented and Kootenay Lake is still above the target elevation, then these IJC exceedances are accepted as unavoidable.

The above procedures do not interpret or modify the actual IJC procedures, and are not intended for use in actual operations of Libby, Duncan, and Kootenay Lake. The procedures are designed solely for use in the Treaty hydroregulation studies.

3. Kerr

Kerr has a non-power requirement to draft empty by April 15th every year, and because it is an annual project, its critical and operating rule curves are set empty on March 31st and April 15th. The ability to meet these targets is significantly limited by powerhouse maximum capability and maximum channel outflow capability, which are a function of reservoir elevation. Large inflows and/or high reservoir elevations in prior months can prevent the project from reaching empty. To help Kerr reach near empty on April 15th, the upper rule curve is set equal to 143.4 cubic meters per second (58.6 thousand cubic feet per second) on March 31st for every water year.

4. Priest Lake

Priest Lake was a natural lake and has been regulated since 1950 by a low head dam that generally controls lake levels and outflows. During times of high inflow and/or low reservoir levels, however, a channel outlet restriction controls levels and outflows. Priest Lake is modeled similar to other U.S. projects in the Step I studies.

Priest Lake is not included in the Base System. However, Priest Lake is included in Step II/III studies and is regulated so as to model the effects of natural lake regulation on the inflows at downstream projects. This is accomplished by setting all operating and critical rule curves to empty, so that only the channel outlet restriction causes a storage operation. Priest Lake is included in Step II/III studies because the 1960 Modified Flows (mentioned in Protocol VIII) included the effect of natural lake regulation at Priest Lake, whereas modern Modified Flows do not.

APPENDIX 3 - FIRM ENERGY SHIFTING

Shifting of firm energy between years of the critical period may be included in the Assured Operating Plan and Determination of Downstream Power Benefits studies in the manner described in this section. This option has been available since the 1993-94 Assured Operating Plan, but thus far only 1993-94, 1994-95, and the rollover of 1994-95 to the 1995-96 Assured Operating Plans have included firm energy shifting.

Firm energy shifting is an operation designed to increase the reliable energy production in most conditions, at the expense of reduced energy capability in later periods of extended low flow conditions. For example, if a utility is forecasting energy surpluses in future (due to new resources becoming operational), it may choose to draft the reservoir system deeper in the current year. Such drafts will increase the firm energy that may be produced in the first year, but reduce the firm energy that can be produced in subsequent years if low water conditions do develop. During most conditions, inflows will be sufficient to meet the higher firm energy demands and refill the reservoirs, however during low inflow periods surplus resources may need to be called on so that energy supply from the hydro system can be reduced. In the right circumstances, this type of operation can enhance overall power generation.

When the U.S. Entity determines that shifting will produce optimum power in the U.S., the Entities shall conduct additional studies that determine the changes to the Assured Operating Plan and the Downstream Power Benefits that would occur if shifted firm energy had not been included.

The purpose of these studies is:

- to provide a non-shifted firm energy operating plan that the U.S. Entity may elect to implement in the Detailed Operating Plan; and
- to define the incremental change in the Downstream Power Benefits due to the inclusion of shifted firm energy.

If the U.S. Entity does not determine that shifting may produce optimum power in the U.S. at the time of preparation of the Assured Operating Plan, the Entities may prepare additional studies that determine the changes to the Assured Operating Plan and the Downstream Power Benefits that would occur if shifted energy had been included. The purpose of these studies is:

- to provide a shifted firm energy operating plan that the Entities may elect to implement in the Detailed Operating Plan; and
- to define the incremental change in Downstream Power Benefits due to the inclusion of shifted firm energy.

If shifted firm energy is included in either the Assured Operating Plan or the Detailed Operating Plan, the Downstream Power Benefits to which Canada is entitled shall be those which include the effect of shifting.

Assured Operating Plan and Downstream Power Benefits studies that include shifted energy shall be similar to other Assured Operating Plan and Downstream Power Benefits studies. The Step I study firm energy load carrying capability may be increased in the first year of the critical period by shifting energy capability uniformly from latter years of the critical period, if:

- the rate of return energy in the latter years of the critical period can be served by critical period surplus firm energy, a backup thermal resource, or a firm load reduction; and

- the amount of energy shifting does not cause the Canadian Treaty Storage to draft more than the following amounts at the end of the first year of the Step I critical period (31 July 1929).

Project	Maximum Permitted Draft	
	ksfd	hm^3
Mica	700	1713
Arrow	300	734
Duncan	143	350

The shifted firm energy shall be used either to meet Pacific Northwest Area firm loads or to increase the initial firm surplus. During the 30-year System Regulation Studies the surplus firm energy shall be shifted into water years that begin on August 1st with the reservoir system energy content at or above a point halfway between full and the first Critical Rule Curve for 31 July. Shifted firm energy shall be returned at uniform monthly rates in all water years that begin with the reservoir system energy content below that point.

Any firm energy shifted in the Step I study shall also be shifted in the Step II study by using the same rate of return energy in both studies. The rate of return of shifted firm energy in the Step I study shall determine the amount of shifting used in the first year of the critical period of the Step II study. The increased firm load in the first year of the Step II critical period study shall be shaped the same as the Pacific Northwest Area load. The Step III study does not have shifted energy because the critical period is less than one year in length.

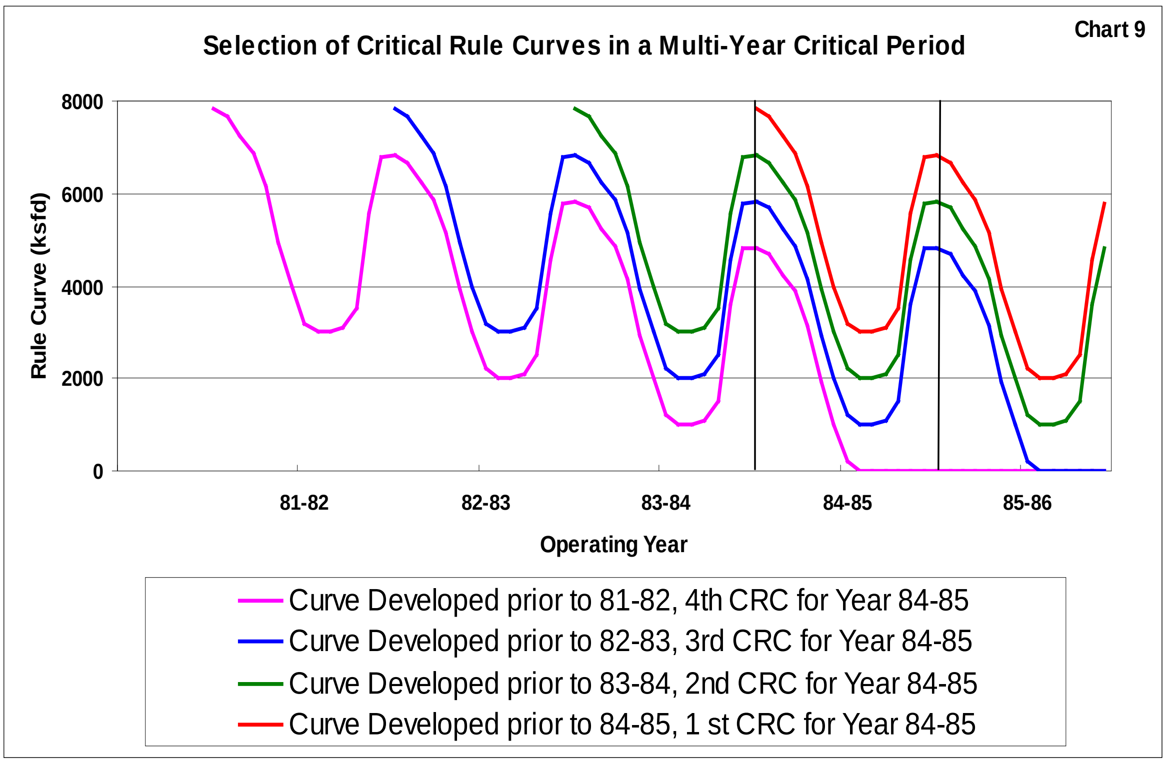
The Step II 30-year System Regulation Study shall raise and lower the firm load using the same criteria as the Step I study. If a backup thermal resource is included to meet loads in latter years of the Step I critical period when shifted energy is returned, it shall be included in the determination of displaceable thermal resources for the Step II study.

APPENDIX 4 – MULTI-YEAR CRITICAL PERIODS

In recent years, studies carried out for the Detailed Operating Plan have indicated that the energy capability of the U.S. reservoir system is limited by a one year critical period of inflows. In such cases, only data for the single Assured Operating Plan for the next year of operation is required to carry out the Detailed Operating Plan studies.

One year critical periods have not always been the norm, however. Prior to 1995, critical period studies of the U.S. system indicated longer critical periods, typically 3.5 years in length. These longer critical periods frequently required updates for rule curves for several Assured Operating Plans to fully optimize future storage operation, particularly if firm energy-shifting operations had been implemented. Such updates can be (and have been) accommodated within the Detailed Operating Plan, if the revisions are mutually beneficial.

For example, with reference to Chart 9, the four Critical Rule Curves for a particular operating year (in this case 1984-85) may come from changes that were agreed to when studies were undertaken in each of the 3 preceding years.



APPENDIX 5 – ARROW LOCAL METHOD

For Computation of Arrow Variable Refill Curve

In several of the past years, the Entities have determined that it is mutually advantageous to modify the methodology for computation of the Variable Refill Curve for the Arrow reservoir.

Rationale

The rationale for this modification is that the upstream Mica project is generally operated to fixed operating rules as described in Section 2.6. As a result, Mica may, at times, draft significantly below its computed Variable Refill Curve. When this occurs, because Canadian Treaty Storage is operated to its composite Operating Rule Curve (see Section 2.4.A), Arrow will generally be required to store significantly above its Variable Refill Curve. This additional storage in Arrow may result in unnecessary power losses in the U.S. system, particularly when the fixed operation at Mica does not allow that project to refill by 31 July.

To address this concern, the Entities have developed the "Arrow Local Method" for determining a modified Variable Refill Curve at Arrow, which may be implemented by mutual agreement. The details of the computation of the Arrow Local Variable Refill Curve have varied slightly over the years, but the general philosophy behind the computation has been to compute a rule curve reflecting the expected outflow from Mica, based on its fixed operation, and to reflect the variability associated with only the local, rather than the total, inflow.

The Arrow Local Method is generally only implemented if the current Treaty Storage Regulation study shows for the end of the current month that (1) the project Mica Treaty storage content is lower than its Operating Rule Curve, and (2) the coordinated system draft point is on the Operating Rule Curve. In addition, during any period when the Arrow Local Method is used, the Mica/Arrow balancing (as described in Section 2.4.A) is not used.

Methodology

The most recent detailed procedures, as described in the most recent Detailed Operating Plan, for computing the Arrow Local Variable Refill Curve for Arrow are as follows:

(a) The forecast volume of inflow for Arrow will exclude the volume of inflow above the Mica project. This Arrow local inflow volume will be reduced by a forecast error such that there is a 95 percent probability that the reduced forecast is equaled or exceeded;

(b) In computing the forecast inflow for Arrow, the 95% local inflow forecast, computed in (a) above, will be increased by the expected Mica target outflow, as determined by the applicable Mica operating criteria; and

(c) In computing the water available for refill of Arrow, the Power Discharge Requirements will be deducted from the forecast inflow for Arrow, determined in (b) above.