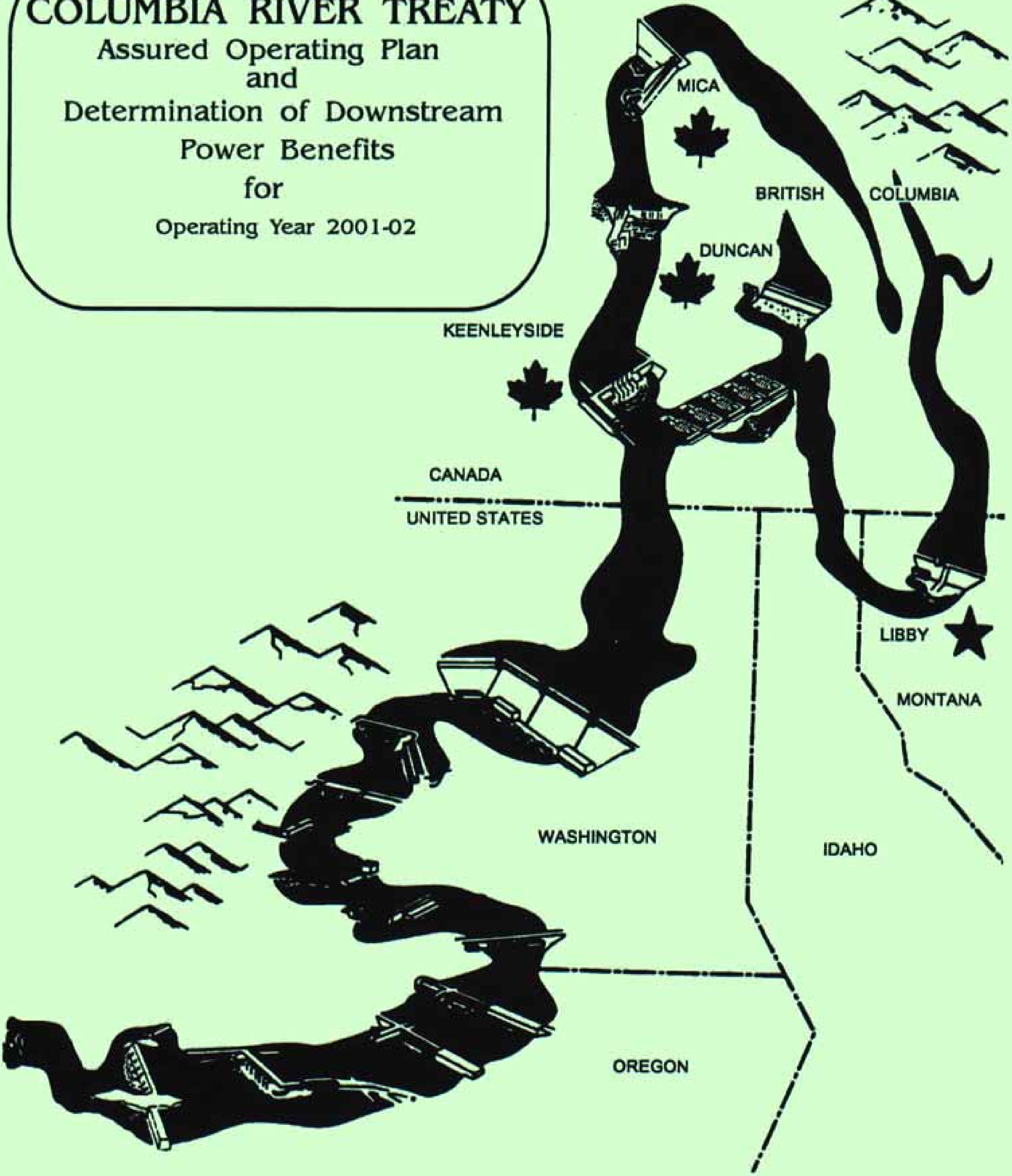
COLUMBIA RIVER TREATY

Assured Operating Plan and Determination of Downstream Power Benefits for

Operating Year 2001-02



Columbia River Treaty Operating Committee

January 2000

COLUMBIA RIVER TREATY ENTITY AGREEMENT ON THE ASSURED OPERATING PLAN AND DETERMINATION OF DOWNSTREAM POWER BENEFITS FOR THE 2001-02 OPERATING YEAR

The Columbia River Treaty between Canada and the United States of America requires that the Entities agree annually on an assured plan of operation for Canadian Treaty storage and on the resulting downstream power benefits six years in advance.

The Entities agree that the attached reports entitled "Columbia River Treaty Assured Operating Plan for Operating Year 2001-02" and "Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2001-02," both dated January 2000, shall be the Assured Operating Plan and Determination of Downstream Power Benefits for the Operating Year 2001-02.

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

Executed for the Canadian Entity this 16th day of February 2000.

By Brian Smith
Brian R.D. Smith, Chair

Executed for the United States Entity this 16th day of February 2000.

By Judi Johansen
Judith A. Johansen, Chairman

By Carl A. Strock
Brigadier General Carl A. Strock, Member

COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
FOR OPERATING YEAR 2001-02

TABLE OF CONTENTS

Section **Page**

1. Introduction 1
2. System Regulation Studies 2
3. Development of the Assured Operating Plan 2
   (a) Determination of Optimum Generation in Canada and the United States 3
   (b) Maximum Permitted Reduction in Downstream Power Benefits 3
4. Rule Curves 4
   (a) Critical Rule Curve 4
   (b) Refill Curve 4
      (1) Assured Refill Curve 4
      (2) Variable Refill Curve 4
   (c) Limiting Rule Curve (LRC) or Energy Content Curve Lower Limit (ECCLL) 5
   (d) Upper Rule Curve (Flood Control) 5
   (e) Operating Rule Curve 5
5. Operating Rules 6
   (a) Operation Above ORC 6
   (b) Operation Below ORC 6
   (c) Mica Project Operation 6
6. Implementation 7
7. Canadian Entitlement 8
   (a) Delivery of the Canadian Entitlement 8
   (b) Capacity/Energy Entitlement Scheduling Guidelines 8
8. Summary of Changes from Previous Year 8
   (a) Loads and Non-Hydro Resources 9
   (b) Operating Procedures 9

REFERENCES 11

Table 1 - Mica Project Operating Criteria (English Units) 13

Table 2 - Comparison of Assured Operating Plan Study Results (English Units) 14

Table 3 - Critical Rule Curves End of Period Treaty Storage Contents (English Units) 15

Table 4 - Mica Assured and Variable Refill Curves (English Units) 16

Table 5 - Arrow Assured and Variable Refill Curves (English Units) 17

Table 6 - Duncan Assured and Variable Refill Curves (English Units) 18

Table 7 - Mica Upper Rule Curves (Flood Control) (English Units) 19

Table 8 - Arrow Upper Rule Curves (Flood Control) (English Units) 20

Table 9 - Duncan Upper Rule Curves (Flood Control) (English Units) 21

Table 10 - Composite Operating Rule Curves for the Whole of Canadian Storage (English Units) 22

Table 11 - Comparison of Recent Assured Operating Plan Studies (English Units) 23

Table 1M - Mica Project Operating Criteria (Metric Units) 24

Table 3M - Critical Rule Curves End of Period Treaty Storage Contents (Metric Units) 25

Table 4M - Mica Assured and Variable Refill Curves (Metric Units) 26

Table 5M - Arrow Assured and Variable Refill Curves (Metric Units) 27

Table 6M - Duncan Assured and Variable Refill Curves (Metric Units) 28

Table 7M - Mica Upper Rule Curves (Flood Control) (Metric Units) 29

Table 8M - Arrow Upper Rule Curves (Flood Control) (Metric Units) 30

Table 9M - Duncan Upper Rule Curves (Flood Control) (Metric Units) 31

Table 10M - Composite Operating Rule Curves for the Whole of Canadian Storage (Metric Units) 32

Table 11M - Comparison of Recent Assured Operating Plan Studies (Metric Units) 33

Appendix A1 - Project Operating Procedures for the 2001-02 (English Units) A1

Appendix A2 - Project Operating Procedures for the 2001-02 (Metric Units) A2

HYDROELECTRIC OPERATING PLAN
ASSURED OPERATING PLAN
FOR OPERATING YEAR 2001-02

January 2000

1. Introduction

The treaty between Canada and the United States of America relating to the cooperative development of the water resources of the Columbia River Basin (Treaty) requires that each year an Assured Operating Plan (AOP) be agreed to by the Entities for the operation of the Columbia River Treaty storage in Canada during the sixth succeeding year. This plan will provide to the Entities information for the sixth succeeding year for planning the power systems in their respective countries which are dependent on or coordinated with the operation of the Canadian storage projects.

This AOP was prepared in accordance with the Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans[1] (POP) and in accordance with the following Entity Agreements:

- The "Columbia River Treaty Entity Agreement on Resolving the Dispute on Critical Period Determination, the Capacity Entitlement for the 1998-99, 1990-00, and 2000-01 AOP/DDPB's, and Operating Procedures for the 2001-02 and Future AOP's," signed 29 August 1996;[2]
- Principles[3] and on Changes to Procedures[4] for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, signed 28 July and 12 August 1988, respectively.

POP is based on criteria contained in Annex A and Annex B of the Columbia River Treaty,[5] the Protocol,[6] the Terms of Sale,[7] and the Columbia River Treaty Flood Control Operating Plan.[8]

In accordance with the Protocol VII (2), this AOP provides a reservoir-balance relationship for each month for the whole of the Canadian storage. This relationship is determined from the following:

(a) The Critical Rule Curve (CRC) for each project, the individual project Upper Rule Curves (URC's), and the related rule curves and data used to compute the individual project Operating Rule Curves (ORC's).

(b) Operating Rules, that specifically designate criteria for operation of the Canadian storage in accordance with the principles contained in the above references.

(c) The supporting data and model used to simulate the 30-year operation for the Step I Joint Optimum hydroregulation study.[9]

This AOP includes both English and metric units.[10] For operational purposes, the English units should be used as having a degree of accuracy consistent with previous year's studies. Calculations based on metric units are approximations derived by rounding conversions from English units. Metric values are displayed with either one or two decimal places to assure consistency with English units and does not imply that level of precision. The inclusion of metric units complies with U.S. Federal statutory requirements. Tables referred to in the text are in English units. Metric tables use the same numbering system with the letter "M" after the table number.

2. System Regulation Studies

In accordance with Annex A, paragraph 7, of the Treaty, the Columbia River Treaty Operating Committee conducted system regulation studies reflecting Canadian storage operation for optimum generation in both Canada and the United States. Downstream power benefits were computed with the Canadian storage operation based on the operating rules specified herein.

System Regulation Studies for the AOP were based on 2001-02 estimated loads and resources in the United States Pacific Northwest System and hydro resources in the Columbia River Basin in British Columbia. In accordance with the Protocol VIII, the 2001-02 AOP is based on a 30-year streamflow period and the Entities have agreed to use an operating year of 1 August to 31 July. Historical flows for the period August 1928 through July 1958, modified by estimated irrigation depletions for the 1990 level and including the latest Grand Coulee pumping were used.[11] The 1990 level is considered the best estimate of irrigation depletions for the 2001-02 operating year.

The CRC's were determined from a critical period study of optimum power generation in both Canada and the United States. The study indicated a 42.5-month critical period for the United States system resulting from the low flows during the period from 16 August 1928 through 29 February 1932. With the major exception of Brownlee and Dworshak, it was assumed that all reservoirs, both in the United States and Canada, were full at the beginning of the critical period except where minimum release requirements made this impossible.

In the studies, individual project flood control criteria were followed. Flood Control and Variable Refill Criteria are based on historical inflow volumes. Although only 15.5 million acre-feet (Maf) (19.12 cubic kilometers (km^3)) of usable storage is committed for power operation purposes under the Treaty, the Columbia River Treaty Flood Control Operating Plan provides for the full draft of the total 20.5 Maf (25.29 km^3) of usable storage for on-call flood control purposes.

3. Development of the Assured Operating Plan

This AOP was developed in accordance with Annex A, paragraph 7 of the Treaty and was designed to produce optimum power generation at-site in Canada and downstream in

Canada and the United States. The Mica Operating criteria specified in Table 1 was evaluated using the two tests described below.

(a) Determination of Optimum Generation in Canada and the United States

To determine whether optimum generation in both Canada and the United States was achieved in the system regulation studies, the firm energy capability, dependable peaking capability, and average annual usable secondary energy were computed for both the Canadian and United States systems.

In the studies for the 2001-02 AOP, the Canadian storage operation was operated to achieve a weighted sum of the three quantities that was greater than the weighted sum achieved under an operation of Canadian storage for optimum generation in the United States of America alone.

In order to achieve a weighted value for the three quantities, the Columbia River Treaty Operating Committee agreed for the 2001-02 AOP that the three quantities would be assigned the following relative values:

Quantity	Relative Value
Firm energy capability (aMW)	3
Dependable peaking capability (MW)	1
Average annual usable secondary energy (aMW)	2

After weighting each quantity, the three quantities were added, resulting in a net gain to the combined Canadian and United States systems in the study designed for optimum generation in Canada and the United States.

Table 2 shows the results from studies adopted for the 2001-02 AOP and from studies designed to achieve optimum generation in the United States alone.

(b) Maximum Permitted Reduction in Downstream Power Benefits

Separate Step II system regulation studies were developed reflecting (i) Canadian storage operation for optimum generation in both Canada and the United States, using the Mica Project operating criteria described in section 5(c) below, and (ii) Canadian storage operation for optimum generation in the United States alone. Using these Mica Project operating criteria, there is a 0.4 aMW increase in the Canadian Entitlement for average annual usable energy and no change in the dependable capacity compared to an operation for optimum generation in the United States alone.

Since there is no reduction in entitlement, the Entities have determined that these changes are within the maximum permitted reduction in downstream power benefits specified by the Treaty.

4. Rule Curves

The operation of Canadian storage during the 2001-02 Operating Year shall be guided by an ORC for the whole of Canadian storage, Flood Control Storage Reservation Curves for the individual projects, CRC's, and operating rules for specific projects. The ORC is derived from the various curves described below. These ORC's are first determined for the individual Canadian projects and then summed to yield the Composite ORC for the whole of Canadian storage, in accordance with paragraph VII(2) of the Protocol.

(a) Critical Rule Curve

The CRC indicates the end-of-period storage content of Canadian storage during the critical period. It is designed to protect the ability of the United States system to serve firm load with the occurrence of flows during the most adverse historical streamflow period. A tabulation of the CRC's for Duncan, Arrow, Mica, and the Composite CRC's for the whole of Canadian storage is included as Table 3.

(b) Refill Curve

The Refill Curves are used to develop the ORC's. The end of the refill period is considered to be 31 July. There are two types of refill curves, the Assured Refill Curve (ARC) and the Variable Refill Curve (VRC), which are discussed in the following sections. In each case, adjustment is made for water required for refill of upstream reservoirs when applicable. Tabulations of the VRC's and outflow schedules used in determining the VRC's and ARC's for Mica, Arrow, and Duncan are provided in Tables 4 - 6, respectively.

(1) Assured Refill Curve

The ARC indicates the end-of-period storage content required to assure refill of Canadian storage based on the 1930-31 water year, which is the system's second lowest historical January through July volume of inflow at The Dalles, Oregon during the 30-year record. A tabulation of the ARC's for Mica, Arrow, and Duncan are included in Tables 4-6. The outflows, or Power Discharge Requirements (PDR's), used in developing these ARC's are also shown in these tables.

(2) Variable Refill Curve

The VRC is provided as a check to ensure that the ARC is not too conservative. The VRC's give end-of-period storage contents for the period January through July required to refill Canadian storage during the refill period. They were based on historical inflow volumes, upstream storage requirements, and PDR's determined in accordance with the POP. In the system regulation studies, the PDR's were made a function of the unregulated January through July runoff volume at The Dalles, Oregon. The PDR's used in computing the VRC's were interpolated linearly between the values shown in Tables 4-6. In those years when the January to July runoff volume at The Dalles was less than 80 Maf (98.68 km^3) or greater than 110 Maf (135.69 km^3), the discharge used was that specified for 80 and 110 Maf (98.68 and 135.69 km^3), respectively.

VRC's for Mica, Arrow and Duncan for the 30 years of historical record in Tables 4-6 illustrate the probable range of these curves based on historical conditions. In actual operation in 2001-02, the PDR's will be based on the forecast of unregulated runoff at The Dalles.

(c) Limiting Rule Curve (LRC) or Energy Content Curve Lower Limit (ECCLL)

The LRC's indicate 31 January through 15 April end-of-period storage contents. These contents must be maintained to protect the ability of the system to meet firm load during the period January through 30 April in the event that the VRC's permit storage to be emptied and sufficient natural flow is not available to carry the load prior to the start of the freshet. Such rule curves shall limit the VRC to be no lower than the LRC. The LRC is developed for 1936-37 water conditions. The LRC's for Mica, Arrow, and Duncan are shown in Tables 4-6, respectively.

(d) Upper Rule Curve (Flood Control)

The URC's indicate the end-of-period storage content to which each individual Canadian storage project shall be evacuated for flood control. The URC's used in the studies were based upon Flood Control Storage Reservation Diagrams contained in the Columbia River Treaty Flood Control Operating Plan[12] and analysis of system flood control simulations.[13] URC's for Mica, Arrow, and Duncan for the 30-year study period are shown on Tables 7 - 9, respectively. Tables 7 and 8 reflect an agreed transfer of flood control space in Mica and Arrow to maximum drafts of 2.08 Maf and 5.1 Maf (2.57 km^3 and 6.29 km^3) respectively. In actual operation, the URC's will be computed as outlined in the Flood Control Operating Plan, using the latest forecast of runoff available at that time.

(e) Operating Rule Curve

The ORC's define the normal limit of storage draft to produce secondary energy and provide a high probability of refilling the reservoirs. In general, the Operating Plan does not permit serving secondary loads at the risk of failing to refill storage and thereby jeopardizing the firm load carrying capability of the United States or Canadian systems during subsequent years.

During the period 1 August through 31 December, the ORC is defined as the CRC for the first year of the critical period or the ARC, whichever is higher. During the period 1 January through 31 July, the ORC is defined as the higher of the CRC and the ARC; unless the VRC is lower, then it defines the ORC. During the period 1 January through 15 April, the ORC will not be lower than the LRC. The ORC shall be less than or equal to the URC. The composite ORC for the whole of Canadian storage for 30 years of historical record are included in Table 10 to illustrate the probable future range of these curves based on historical conditions. The lower of the Energy Content Curves for United States reservoirs or the URC's are equivalent to ORC's.

5. Operating Rules

A 30-year System Regulation Study[14] was utilized to develop and test the operating rules and rule curves. It contains the agreed-upon operating and CRC's, operating rules and constraints, such as maximum and minimum project elevations, discharges, draft rates, etc. These constraints are included as part of this operating plan, as found in Appendix A1 (English units) or Appendix A2 (Metric units).

The following rules, used in the 30-year System Regulation Study, will apply to the operation of Canadian storage in the 2001-02 Operating Year.

(a) Operation Above ORC

The whole of the Canadian storage will be drafted to its ORC as required to produce optimum generation in Canada and the United States in accordance with Annex A, paragraph 7, of the Treaty, subject to project physical characteristics, operating constraints, and the criteria for the Mica project listed in section 5(c).

(b) Operation Below ORC

The whole of Canadian storage will be drafted below its ORC as required to produce optimum generation to the extent that a System Regulation Study determines that proportional draft below the ORC is required to produce the hydro firm energy load carrying capability (FELCC) of the United States system. FELCC is determined by the applicable Critical Period Regulation study. Proportional draft between rule curves will be determined as described in the POP.

Mica Reservoir will, however, continue to be operated in accordance with section 5(c) below, so as to optimize generation at site and at Revelstoke as well as downstream in the United States. In the event the Mica operation results in more or less than the project's proportional share of draft from the whole of Canadian storage, compensating changes will be made from Arrow to the extent possible.

(c) Mica Project Operation

Mica project operation will be determined by Arrow's storage content at the end of the previous period as shown in Table 1. Mica outflows will be increased above the values shown in the table in the periods from October through June if required to avoid storage above the URC.

Under this AOP, Mica storage releases in excess of 7.0 Maf (8.63 km^3) that are required to maintain the Mica outflows specified under this plan will be retained in the Arrow reservoir, subject to flood control and other project operating criteria at Arrow. The total combined storage draft from Mica and Arrow will not exceed 14.1 Maf (17.39 km^3), unless flood control criteria will not permit the additional Mica storage releases to be retained at Arrow. Should storage releases in excess of 14.1 Maf (17.39 km^3) be made, the target Mica operation will remain as specified in Table 1.

Revelstoke, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile, and Waneta have been included in the 2001-02 AOP and have been operated as run-of-river projects. Corra Linn and Kootenay Canal were included in the study and operated in accordance with criteria that closely approximates International Joint Commission rules for Kootenay Lake.

6. Implementation

The Entities have agreed that each year a Detailed Operating Plan (DOP) will be prepared for the immediately succeeding operating year. Such DOP's are made under authority of Article XIV 2.(k) of the Columbia River Treaty, which states:

"...the powers and the duties of the entities include:

(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."

The 2001-02 DOP will reflect the latest available load, resource, and other pertinent data to the extent the Entities agree these data should be included in the plan.

The data and criteria contained herein may be reviewed, and updated as agreed by the Entities, to form the basis for a 2001-02 DOP. Failing agreement on updating the data and/or criteria, the 2001-02 DOP will include the rule curves, Mica operating criteria, and other data and criteria provided in this AOP. Actual operation during the 2001-02 Operating Year shall be guided by the DOP.

The values used in the AOP studies to define the various rule curves were period-end values only. In actual operation, it is necessary to operate in such a manner during the course of each period that these period-end values can be achieved in accordance with the operating rules. Due to the normal variation of power load and streamflow during any period, straight-line interpolation between the period-end points should not be assumed.

During the storage drawdown season, Canadian storage should not be drafted below its period-end point at any time during the period unless it can be conservatively demonstrated that sufficient inflow is available, in excess of the minimum outflow required to serve power demand, to refill the reservoir to its end-of-period value as required. During the storage evacuation and refill season, operation will be consistent with the Flood Control Operating

Plan. When refill of Canadian storage is being guided by Flood Control Refill Curves, such curves will be computed on a day-by-day basis using the residual volume-of-inflow forecasts depleted by the volume required for minimum outflow, unless higher flows are required to meet firm load, from each day through the end of the refill season. [15]

7. Canadian Entitlement

On 1 April 1998 and on 1 April 1999, the portions of the Canadian Entitlement to downstream power benefits attributed to the operation of Duncan and Arrow dams, respectively, cease to be covered by the Terms of the Sale of the Canadian Entitlement in the United States of America authorized by an Exchange of Notes between Canada and the United States of America dated 16 September 1964.[16] This AOP has been prepared on the basis that the portion of the Canadian Entitlement attributable to Duncan (i.e., 1.4 Maf/ 15.5 Maf) [1.72 km^3/ 19.12 km^3] will be returned to Canada starting 1 April 1998, and the portion attributable to Arrow (i.e., 7.1 Maf/ 15.5 Maf) [8.76 km^3 / 19.12 km^3] will be returned starting 1 April 1999.

(a) Delivery of the Canadian Entitlement

The Treaty specifies return of the Canadian Entitlement at a point near Oliver, British Columbia, unless otherwise agreed by the Entities. Because no cross border transmission exists at any point on the Canada-United States of America boundary near Oliver, the Entities completed an agreement on Aspects of the Canadian Entitlement Return for 1 April 1998 through 31 March 2003,[17] executed 28 July 1992. This agreement has now been replaced by the Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for 1 April 1998 through 15 September 2024, dated 29 March 1999.[18] This arrangement covers the full 1 August 2001 through 31 July 2002 period covered by this AOP.

(b) Capacity/Energy Entitlement Scheduling Guidelines

The Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for 1 April 1998 through 15 September 2024,[19] specifies the scheduling guidelines for delivery of the Canadian Entitlement.

8. Summary of Changes from Previous Year

Data from the five most recent AOP's are summarized in Table 11. Firm energy shifting was not included in the 1997-98, 1998-99, 1999-00, 2000-01 and the 2001-02 operating plan studies. An explanation of the more important changes compared to last year's studies follows.

(a) Loads and Non-Hydro Resources

Loads for the 2001-02 AOP were based on the 1995 Whitebook medium case forecast developed by BPA in November 1995. Compared to the previous AOP, The Pacific Northwest Area (PNWA) firm energy load increased by 534 aMW. The total exports, not including firm surplus energy, increased by 89 aMW. The increase in exports is mainly due to the increased Canadian Entitlement Return. It was assumed that all of the Entitlement Return was exported to B.C. with one-half of the amount imported back to meet load in the PNWA. The surplus firm energy decreased by 426 aMW and was shaped only in May and June.

The beginning of the Step I critical period study changed from 1 September to 16 August 1928 because of an increase in firm energy load in August compared to loads in the previous year's study.

The total annual energy capability of the thermal installations decreased by 8 aMW. Major thermal resource changes included (see Table 1A of DDPB document):

- Combustion Turbine resources decreased by 139 aMW due to removal of BPA's Tenaska and Idaho's Wood River projects, and removal of maintenance at PGE's Beaver and Unnamed projects;

- Cogeneration decreased 42 aMW due to the removal of the Klickitat SDS Lumber project and a change in the maintenance schedule for PGE's Coyote Springs;

- Boardman Coal increased by 107 aMW due to a change in maintenance schedule and an upgrade;

- Thermal Non-Utility Generation (NUGs) decreased by 34 aMW mostly due to the termination of Springfield's and Clallam County's NUG's, and a decrease in WWP's;

- Thermal Imports increased by 107 aMW due to changes in the Southern California Edison (SCE) to BPA imports, and addition of a new import from Imperial to BPA. Montana Thermal Import decreased and showed different monthly shaping from the previous year's data; and

- Plant Sales increased by 8 aMW due to a change in the maintenance schedule for Boardman, thus PGE's share which was sold to San Diego also increased. This amount is subtracted from the thermal installations.

(b) Operating Procedures

Plant data for Waneta, 7-Mile, Arrow, Rock Island, and the Lower Snake projects were revised. Generation increased due to an upgrade at Waneta and an expansion at 7-Mile. The addition of generators at Arrow is assumed not to be completed by

2002. The generation vs. discharge (MW/cfs) table was updated for Rock Island. The end storage vs. elevation and head vs. H/K (kW/cfs) tables were updated for Ice Harbor. Lower Monumental, Little Goose, and Lower Granite had minor changes to the end storage vs. elevation tables.

The established operating procedures for Base system projects were agreed to by an Entity Agreement signed on 29 August 1996.[20] These requirements are essentially the nonpower requirements included in the 1979-80 and prior AOP/DDPB studies. Major changes from the previous studies included:

- Hungry Horse minimum flow requirement increased to 400 cfs (11.33 m^3/s) from 145 cfs (4.11 m^3/s), all periods. The requirement to meet Columbia Falls minimum flow of 3500 cfs (99.11 m^3/s), and the maximum of 4500 cfs (127.43 m^3/s) was eliminated;

- Kerr minimum flow decreased to 1500 cfs (42.47 m^3/s) in all periods. In the previous year's AOP, minimum flow ranged from 3200 cfs (90.61 m^3/s) in most periods to a high of 7742 cfs (219.23 m^3/s) in May;

- Only the 1240 ft (377.95 m) pumping requirement in May remained for Grand Coulee. The 1285 ft (391.67 m) minimum storage for recreation, and 1220 ft (371.86 m) minimum for Ferry operations were eliminated;

- All fish spill was eliminated for base system projects (not including fish ladders, lockage, sluiceway); and

- John Day was operated to pre-2001 operation with minimum operating pool of 265-ft (80.77 m).

Other notable changes in non-power constraints for non-base system projects include revision of last year's spill data, and Dworshak outflows. For further details, see Appendix A1 (English units) or Appendix A2 (Metric units).

REFERENCES

1 "Columbia River Treaty Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans, Columbia River Treaty Operating Committee," dated December 1991.

2 "Columbia River Treaty Entity Agreement on Resolving the Dispute on Critical Period Determination, the Capacity Entitlement for the 1998-99, 1990-00, and 2000-01 AOP/DDPB's, and Operating Procedures for the 2001-02 and Future AOP's," signed 29 August 1996.

3 "Columbia River Treaty Entity Agreement on Principles for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies," dated 28 July 1988.

4 "Columbia River Treaty Entity Agreement on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies," dated 12 August 1988.

5 "Treaty between the United States of America and Canada relating to Cooperative Development of the Water Resources of the Columbia River Basin," dated 17 January 1961.

6 "Protocol - Annex to Exchange of Notes," dated 22 January 1964.

7 "Attachment Relating to Terms of Sale - Attachment to Exchange of Notes," dated 22 January 1964.

8 "Columbia River Treaty Flood Control Operating Plan," dated October 1972, as amended by the "Review of Flood Control, Columbia River Basin, Columbia River and Tributaries Study, CRT-63," dated June 1991.

9 BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 02-41," dated 9 January 1997.

10 The conversion factors used are: (a) million acre-feet (Maf) times 1.2335 equals cubic kilometers (km^3); (b) thousand second-foot-days (ksfd) times 2.4466 equals cubic hectometers (hm^3); (c) cubic feet per second (cfs) divided by 35.3147 equals cubic meters per second (m^3/s); and (d) feet (ft) times 0.3048 equals meters (m).

11 "Report on 1990 Level Modified Streamflows, 1928 to 1989, Columbia River and Coastal Basins, prepared for BPA," dated July 1993.

12 See footnote 8.

13 Summary of "End-of-Period Reservoir Storage Requirement from Columbia River Flood Regulation Studies," dated July 1996.

14 See footnote 9.

15 See footnote 8.

16 Exchange of notes "Regarding the Disposal of the Canadian Entitlement to Downstream Power Benefits," dated 16 September 1964.

17 Columbia River Treaty Entity Agreement on Aspects of the Canadian Entitlement Return for 1 April 1998 through 31 March 2003," executed 28 July 1992.

18 "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.

19 See footnote 18.

20 See footnote 2.

TABLE 1
(English Units)
MICA PROJECT OPERATING CRITERIA
2001-02 ASSURED OPERATING PLAN

Period	End of Previous Period Arrow Storage Content (ksfd)	Target Operation: Period Average Outflow (cfs)	Target Operation: End-of-Period Treaty Content 1/ (ksfd)	Minimum Outflow (cfs)	Minimum Treaty Storage Content 2/ (ksfd)
August 1-15	2600 - FULL	-	3486.2	15000	0.0
	1650 - 2600	16000			
	0 - 1650	26000			
August 16-31	3400 - FULL	-	3529.2	15000	0.0
	1450 - 3400	21000			
	0 - 1450	26000			
September	3460 - FULL	-	3529.2	10000	0.0
	1810 - 3460	22000			
	0 - 1810	27000			
October	3095 - FULL	-	3396.2	10000	0.0
	2030 - 3095	21000			
	0 - 2030	28000			
November	2900 - FULL	20000		12000	0.0
	2620 - 2900	22000			
	950 - 2620	24000			
	0 - 950	29000			
December	3050 - FULL	22000		21000	207.0
	2510 - 3050	25000			
	1000 - 2510	27000			
	0 - 1000	29000			
January	2570 - FULL	24000		15000	106.2
	2490 - 2570	23000			
	1512 - 2490	26000			
	0 - 1512	28000			
February	1510 - FULL	21000		15000	0.0
	380 - 1510	23000			
	365 - 380	21000			
	0 - 365	28000			
March	1285 - FULL	22000		15000	0.0
	740 - 1285	20000			
	675 - 740	24000			
	0 - 675	27000			
April 1-15	1655 - FULL	-	326.2	13000	0.0
	1450 - 1655	-	16.2		
	1000 - 1450	18000			
	0 - 1000	-	0.0		
April 16-30	2780 - FULL	-	56.2	10000	0.0
	2590 2780	-	0.0		
	800 - 2590	10000			
	0 - 800	13000			
May	300 - FULL	10000		8000	0.0
	295 - 300	8000			
	194 - 295	14000			
	0 - 194	22000			
June	1280 - FULL	10000		8000	0.0
	1160 - 1280	8000			
	480 - 1160	12000			
	0 - 480	17000			
July	1940 - FULL	-	3456.2	8000	0.0
	1800 - 1940	17000			
	0 - 1800	24000			

Notes:

1/ A maximum outflow of 34000 cfs will apply if the target end-of-period storage content @ Mica is less than 3529.2 ksfd in every month except April, May, and June. For these periods, the maximum outflow is 32000 cfs in April 1-15, 27000 cfs in April 16-30, 30000 cfs in May, and 33000 cfs in June.

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

TABLE 2
COMPARISON OF 2001-02 ASSURED OPERATING PLAN
STUDY RESULTS

Study 02-41 provides Optimum Generation in Canada and in the United States.
Study 02-11 provides Optimum Generation in the United States only.

	Study No. 02-41	Study No. 02-11	Net Gain	Weight	Value
1. Firm Energy Capability (aMW)					
U.S. System 1/	12020.5	12020.3	0.2		
Canada 2/, 3/	2830.0	2781.7	48.3		
Total	14850.5	14802.0	48.5	3	145.5
2. Dependable Peaking Capacity (MW)					
U.S. System 4/	31244.0	31244.0	0.0		
Canada 2/, 5/	5622.0	5597.0	25.0		
Total	36866.0	36841.0	25.0	1	25.0
3. Average Annual Usable Secondary Energy (aMW)					
U.S. System 6/	3243.4	3218.5	24.9		
Canada 2/, 7/	240.9	270.6	-29.7		
Total	3484.3	3489.1	-4.8	2	-9.6
			Net Change in Value =		160.9

1/ U.S. System firm energy capability was determined over the U.S. system critical period beginning 16 August 1928 and ending 29 February 1932.

2/ Canadian system includes Mica, Arrow, Revelstoke, Kootenay Canal, Corra Linn, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile, and Waneta.

3/ Canadian system firm energy capability was determined over the Canadian system critical period beginning 1 October 1940 and ending 30 April 1946.

4/ U.S. system dependable peaking capability was determined from January 1937.

5/ Canadian system dependable peaking capability was determined from December 1944.

6/ U.S. system 30-year average secondary energy limited to secondary market.

7/ Canadian system 30-year average generation minus firm energy capability.

TABLE 3
(English Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2001 - 02 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	3529.2	3529.2	3340.9	3109.0	3007.9	2594.8	1779.8	1221.4	1225.8	523.5	204.3	664.5	2312.0	3374.7
1929-30	3511.0	3478.7	3110.6	2577.7	1732.4	1675.2	712.6	565.8	561.7	39.7	12.9	651.9	1858.2	2969.9
1930-31	3118.2	3047.5	2992.4	2567.8	1727.1	1521.1	676.8	559.4	546.2	65.9	1.1	0.0	778.7	1703.1
1931-32	1718.6	1563.1	1511.2	1360.4	1022.3	176.1	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	3579.6	3575.0	3406.3	3222.4	2994.6	2295.6	1542.9	1352.6	1362.7	817.3	334.0	1075.9	2406.5	3372.8
1929-30	3543.3	3506.7	3208.9	3199.4	2860.8	1717.5	801.5	848.8	774.0	426.1	284.7	689.0	1801.4	3005.2
1930-31	3166.6	3092.2	3055.2	3095.0	2869.1	1560.3	800.8	592.5	561.0	360.7	25.2	486.8	1652.3	1698.8
1931-32	1722.3	1653.1	1607.0	1323.7	696.9	614.5	99.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	705.8	702.0	665.0	640.0	472.3	420.0	240.0	170.0	123.0	117.9	126.3	243.8	518.6	705.5
1929-30	705.8	684.8	685.5	660.2	476.9	240.0	63.8	40.0	2.1	11.9	21.6	118.6	329.4	523.7
1930-31	586.6	653.7	660.0	640.0	470.6	240.3	61.1	40.0	1.8	8.6	8.3	70.0	307.9	510.0
1931-32	480.0	450.0	430.0	250.0	100.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	7814.6	7806.2	7412.2	6971.4	6474.8	5310.4	3562.7	2744.0	2711.5	1458.7	664.6	1984.2	5237.1	7453.0
1929-30	7760.1	7670.2	7005.0	6437.3	5070.1	3632.7	1577.9	1454.6	1337.8	477.7	319.2	1459.5	3989.0	6498.8
1930-31	6871.4	6793.4	6707.6	6302.8	5066.8	3321.7	1538.7	1191.9	1109.0	435.2	34.6	556.8	2738.9	3911.9
1931-32	3920.9	3666.2	3548.2	2934.1	1819.2	792.6	110.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 4
(English Units)
MICA
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2001 - 02 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	1164.0	1728.2	2331.5	2509.8	2575.1	2591.6	2586.4	2099.0	1578.8	1349.0	1127.2	1315.1	2460.4	3529.2
VARIABLE REFILL CURVES (KSFD)														
1928-29							2977.6	2676.1	2423.2	2297.3	2247.9	2145.7	2830.8	3529.2
1929-30							1953.6	1612.5	1349.0	1242.6	1325.2	1533.1	2546.6	..
1930-31							2213.1	1880.9	1613.2	1484.8	1497.9	1553.2	2621.8	..
1931-32							833.4	704.3	659.7	562.6	647.9	1044.4	2440.3	..
1932-33							737.7	644.0	616.7	517.6	556.7	940.7	2276.9	..
1933-34							651.6	399.3	0.0	0.1	0.0	686.7	2529.6	..
1934-35							1369.5	1181.0	1081.9	990.8	1005.9	1230.5	2379.5	..
1935-36							1244.8	1033.9	901.7	787.4	828.8	1195.2	2644.6	..
1936-37							2965.8	2643.7	2376.0	2239.3	2238.2	2159.4	2863.1	..
1937-38							1110.9	998.8	954.6	861.5	909.7	1269.6	2531.8	..
1938-39							2017.2	1753.5	1499.5	1397.2	1432.7	1576.7	2854.6	..
1939-40							1804.2	1496.6	1259.7	1151.5	1209.1	1369.6	2614.4	..
1940-41							2395.0	2083.7	1835.7	1726.4	1821.0	1933.5	2844.6	..
1941-42							1880.0	1691.8	1567.6	1447.6	1460.7	1654.7	2709.1	..
1942-43							1746.6	1612.4	1570.6	1467.4	1563.7	1902.4	2770.2	..
1943-44							3080.1	2735.3	2481.4	2347.7	2324.8	2266.6	3001.8	..
1944-45							2904.1	2622.6	2403.9	2289.7	2251.2	2172.5	2914.7	..
1945-46							651.6	399.3	340.9	231.9	289.8	737.6	2434.7	..
1946-47							..	560.0	542.5	454.8	533.1	1004.2	2505.2	..
1947-48							..	488.3	455.5	341.9	386.3	797.9	2391.9	..
1948-49							2293.9	2159.4	2101.3	1997.1	2010.2	2185.9	3163.4	..
1949-50							953.3	804.4	748.2	638.9	682.6	1021.0	2203.2	..
1950-51							944.5	843.3	819.2	727.6	798.3	1141.2	2564.7	..
1951-52							1351.2	1207.4	1158.2	1042.7	1076.5	1439.2	2712.0	..
1952-53							1632.3	1506.5	1467.1	1363.9	1370.6	1595.7	2678.9	..
1953-54							651.6	399.3	378.7	283.1	332.1	713.3	2175.3	..
1954-55							1268.0	1170.2	1146.9	1056.9	1095.1	1364.8	2369.7	..
1955-56							816.5	701.0	656.5	549.9	599.1	1038.2	2479.2	..
1956-57							985.0	862.3	832.6	738.0	784.6	1125.1	2809.8	..
1957-58							818.8	709.0	685.6	596.5	661.2	1020.9	2572.3	..
LIMITING RULE CURVE (KSFD)							651.6	399.3	0.0	0.1				

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVES														
	3000	3000	3000	3000	3000	3000	3000	20000	20000	20000	22000	22000	22000	22000
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
80 MAF --							3000	10000	10000	10000	12000	20000	20000	20000
95 MAF --							3000	3000	3000	8000	10000	12000	15000	18000
110 MAF --							3000	3000	3000	8000	10000	12000	15000	18000

TABLE 5
(English Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2001 - 02 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	141.3	1062.9	2293.4	2825.7	3061.3	3526.9	3579.6	3290.2	2807.7	2598.0	2377.3	2750.5	3514.2	3579.6
VARIABLE REFILL CURVES (KSFD)														
1928-29							3213.3	3086.3	3030.7	2992.8	3285.9	3450.4	3579.6	3579.6
1929-30							2216.7	1974.8	1746.6	1619.9	2050.2	2841.9	3578.6	..
1930-31							2424.9	2137.0	1886.6	1870.6	2254.4	2676.7	3579.6	..
1931-32							771.0	435.5	0.0	210.5	555.5	1384.4	2904.7	..
1932-33							..	682.6	667.9	702.4	927.1	1556.5	2853.2	..
1933-34							..	435.5	194.9	289.4	814.4	1970.1	3371.3	..
1934-35							1264.9	1161.6	1148.5	1154.8	1333.9	1920.6	3042.2	..
1935-36							1397.3	1182.1	990.0	921.6	1078.8	1931.4	3489.4	..
1936-37							3533.5	3352.7	3297.2	3220.0	3522.2	3579.6	3579.6	..
1937-38							1290.1	1222.3	1216.1	1284.7	1490.0	2042.5	3213.3	..
1938-39							2352.7	2053.1	1764.4	1669.7	2142.0	2761.8	3579.6	..
1939-40							2085.5	1832.4	1596.9	1567.8	1916.3	2541.9	..	..
1940-41							2876.1	2617.5	2610.6	2711.9	3304.5	3579.6	..	..
1941-42							2433.2	2280.2	2170.6	2226.5	2630.3	3008.1	..	..
1942-43							2479.2	2344.1	2306.1	2417.4	2870.5	3388.4	..	..
1943-44							3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	..	..
1944-45							3255.7	3207.2	3253.3	3254.1	3527.8	..	..	..
1945-46							771.0	592.8	579.5	617.4	864.7	1550.7	3053.7	..
1946-47							1178.8	1031.3	1006.7	1063.4	1308.6	1946.5	3181.1	..
1947-48							931.1	873.9	850.6	854.5	1033.1	1631.9	3056.3	..
1948-49							1555.9	1503.6	1967.0	2115.3	2544.8	3078.8	3579.6	..
1949-50							899.0	795.7	796.4	833.4	1036.2	1573.2	2738.6	..
1950-51							1187.8	1131.2	1140.8	1144.3	1375.4	1917.9	3316.3	..
1951-52							1237.0	1134.4	1129.7	1139.6	1317.6	2099.8	3430.6	..
1952-53							1623.0	1522.6	1515.8	1550.7	1917.9	2381.1	3378.4	..
1953-54							771.0	435.5	382.0	435.4	652.6	1255.3	2727.4	..
1954-55							949.7	910.7	926.9	943.1	1150.7	1684.6	2704.9	..
1955-56							771.0	572.7	562.9	595.1	830.0	1615.7	3071.5	..
1956-57							..	606.6	588.9	609.8	848.0	1456.5	3525.5	..
1957-58							..	435.5	455.6	557.8	850.9	1484.3	3187.5	..
LIMITING RULE CURVE (KSFD)							771.0	435.5	0.0	0.6				
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVES														
	5000	5000	5000	5000	5000	5000	5000	40000	40000	40000	50000	50000	51000	52000
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
80 MAF --							5000	18000	20000	20000	22000	30000	42000	44000
95 MAF --							5000	5000	5000	8000	20000	27000	37000	37000
110 MAF --							5000	5000	5000	8000	20000	27000	37000	37000

TABLE 6
(English Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2001 - 02 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	114.3	185.2	251.5	282.2	299.7	310.9	321.1	291.1	261.8	254.0	246.2	360.0	540.9	705.8
VARIABLE REFILL CURVES (KSFD)														
1928-29							449.0	439.3	442.7	449.8	454.2	490.4	616.9	705.8
1929-30							447.3	437.3	440.4	447.2	465.6	511.1	628.3	"
1930-31							391.9	383.1	389.7	401.7	412.5	460.0	616.9	"
1931-32							64.2	56.3	70.1	87.4	136.9	274.4	529.1	"
1932-33							59.1	16.0	0.0	0.0	0.0	96.6	394.7	"
1933-34							"	63.7	82.8	106.1	182.7	334.6	587.1	"
1934-35							165.3	163.9	180.9	192.9	216.1	323.0	526.4	"
1935-36							121.9	115.0	121.8	131.6	157.2	295.6	560.5	"
1936-37							396.9	387.1	392.2	399.2	404.5	452.4	599.1	"
1937-38							134.9	134.3	146.0	162.2	198.7	330.3	553.7	"
1938-39							243.9	240.5	249.3	260.4	281.6	371.8	599.7	"
1939-40							227.3	229.3	245.4	266.1	288.7	373.9	588.3	"
1940-41							309.3	308.1	320.2	342.1	371.9	451.3	612.0	"
1941-42							272.4	273.5	285.9	298.9	322.8	418.6	591.9	"
1942-43							265.7	260.6	270.5	281.3	316.1	441.3	586.6	"
1943-44							465.1	460.8	469.1	478.3	484.2	523.5	647.1	"
1944-45							382.2	378.3	387.3	396.6	403.1	452.4	605.1	"
1945-46							59.1	16.0	12.6	24.1	65.5	220.1	522.5	"
1946-47							"	40.2	51.3	65.3	108.6	263.2	535.2	"
1947-48							92.1	88.8	101.2	111.7	145.1	280.3	545.5	"
1948-49							320.7	312.4	318.8	326.7	352.6	454.6	647.4	"
1949-50							123.7	116.4	125.4	134.3	165.2	289.1	489.7	"
1950-51							59.1	42.9	58.5	68.2	110.0	254.7	520.7	"
1951-52							153.2	147.4	159.5	169.9	202.4	339.7	565.8	"
1952-53							152.1	146.6	157.9	169.0	199.5	318.0	532.1	"
1953-54							59.1	16.0	0.0	0.0	36.1	181.7	462.8	"
1954-55							89.9	86.3	97.6	110.1	142.2	267.6	466.5	"
1955-56							59.1	16.0	9.0	19.9	59.7	228.3	518.4	"
1956-57							104.3	94.5	103.0	114.2	150.9	281.8	582.7	"
1957-58							59.1	16.0	19.4	33.3	73.4	219.0	534.5	"
LIMITING RULE CURVE (KSFD)							59.1	16.0	0.0	0.0				

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVES	100	100	100	100	100	100	100	1500	1500	1500	1500	1500	2000	2000
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
80 MAF --							100	100	100	100	1500	1800	2700	2900
95 MAF --							100	100	100	100	400	600	2700	2900
110 MAF --							100	100	100	100	400	600	2700	2900

TABLE 7
(English Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2001 - 02 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	3529.2	3529.2	3529.2	3428.4	3428.4	3428.4	3385.7	3347.2	3304.6	3304.6	3304.6	3369.1	3447.9	3529.2
1929-30	"	"	"	"	"	"	3352.6	3284.4	3208.7	3208.7	3208.7	3300.7	3413.2	"
1930-31	"	"	"	"	"	"	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	"
1931-32	"	"	"	"	"	"	3105.7	2803.2	2480.5	2480.5	2480.5	2781.5	3149.6	"
1932-33	"	"	"	"	"	"	3101.7	2807.2	"	"	"	"	"	"
1933-34	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1934-35	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1935-36	"	"	"	"	"	"	3105.7	2803.2	"	"	"	"	"	"
1936-37	"	"	"	"	"	"	3330.6	3242.3	3144.5	3144.5	3144.5	3323.3	3398.4	"
1937-38	"	"	"	"	"	"	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	"
1938-39	"	"	"	"	"	"	3193.8	2981.4	2746.8	2746.8	2746.8	2971.4	3246.0	"
1939-40	"	"	"	"	"	"	3274.3	3130.5	2976.4	2976.4	2976.4	3135.1	3329.1	"
1940-41	"	"	"	"	"	"	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	"
1941-42	"	"	"	"	"	"	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	"
1942-43	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1943-44	"	"	"	"	"	"	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	"
1944-45	"	"	"	"	"	"	3193.1	2980.2	2745.0	2745.0	2745.0	2970.0	3245.3	"
1945-46	"	"	"	"	"	"	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1947-48	"	"	"	"	"	"	3105.7	2803.2	"	"	"	"	"	"
1948-49	"	"	"	"	"	"	3101.7	2807.2	"	"	"	"	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1951-52	"	"	"	"	"	"	3105.7	2803.2	"	"	"	"	"	"
1952-53	"	"	"	"	"	"	3101.7	2807.2	"	"	"	"	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1955-56	"	"	"	"	"	"	3105.7	2803.2	"	"	"	2695.5	3172.7	"
1956-57	"	"	"	"	"	"	3101.7	2807.2	"	"	"	2781.5	3149.6	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	"	"	"

TABLE 8
(English Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2001 - 02 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	3579.6	3579.6	3579.6	3453.6	3453.6	3075.4	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	3579.6
1929-30	"	"	"	"	"	"	2998.3	2928.3	2851.2	2870.1	2902.9	3082.8	"	"
1930-31	"	"	"	"	"	"	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	"	"
1931-32	"	"	"	"	"	"	2371.6	1712.7	1008.3	1016.0	1126.6	2224.5	"	"
1932-33	"	"	"	"	"	"	2363.5	1720.2	"	1008.3	1036.6	1761.7	3034.5	"
1933-34	"	"	"	"	"	"	"	"	"	"	1784.9	2327.4	3579.6	"
1934-35	"	"	"	"	"	"	"	"	"	"	1008.3	1725.7	3034.5	"
1935-36	"	"	"	"	"	"	2371.6	1712.7	"	1070.0	1373.5	2134.5	3579.6	"
1936-37	"	"	"	"	"	"	2940.8	2818.8	2684.1	2707.4	2755.8	3266.2	"	"
1937-38	"	"	"	"	"	"	2363.5	1720.2	1008.3	1082.9	1278.3	1831.1	3147.6	"
1938-39	"	"	"	"	"	"	2584.5	2141.3	1650.3	1719.8	1843.2	2661.3	3579.6	"
1939-40	"	"	"	"	"	"	2793.3	2529.4	2247.3	2287.2	2380.5	2913.4	"	"
1940-41	"	"	"	"	"	"	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	"	"
1941-42	"	"	"	"	"	"	2363.5	1720.2	1008.3	1064.9	1149.8	1934.0	"	"
1942-43	"	"	"	"	"	"	"	"	"	1111.2	1322.0	1440.3	2389.1	"
1943-44	"	"	"	"	"	"	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	"
1944-45	"	"	"	"	"	"	2582.9	2138.0	1645.5	1672.5	1744.1	2368.8	3347.5	"
1945-46	"	"	"	"	"	"	2363.5	1720.2	1008.3	1072.6	1242.3	2201.4	3579.6	"
1946-47	"	"	"	"	"	"	"	"	"	1075.2	1360.6	2147.4	"	"
1947-48	"	"	"	"	"	"	2371.6	1712.7	"	1036.6	1183.2	2216.8	"	"
1948-49	"	"	"	"	"	"	2363.5	1720.2	"	1144.6	1376.0	2494.5	"	"
1949-50	"	"	"	"	"	"	"	"	"	1008.3	1008.3	1113.8	2232.3	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	1355.5	3337.9	"
1951-52	"	"	"	"	"	"	2371.6	1712.7	"	1070.0	1345.2	1792.6	3013.9	"
1952-53	"	"	"	"	"	"	2363.5	1720.2	"	1057.2	1172.9	1476.3	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	1134.3	1628.0	1898.0	"
1954-55	"	"	"	"	"	"	"	"	"	1075.2	1090.6	1653.7	3224.8	"
1955-56	"	"	"	"	"	"	2371.6	1712.7	"	1008.3	1216.6	1990.6	2993.4	"
1956-57	"	"	"	"	"	"	2363.5	1720.2	"	1077.8	1224.3	2651.4	3579.6	"
1957-58	"	"	"	"	"	"	"	"	"	1046.9	1190.9	2242.5	"	"

TABLE 9
(English Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2001 - 02 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	705.8	705.8	705.8	705.8	705.8	504.1	418.3	340.8	340.8	348.1	360.5	443.7	574.4	705.8
1929-30	"	"	"	"	"	"	408.4	322.1	322.1	329.8	342.8	430.3	567.7	"
1930-31	"	"	"	"	"	"	391.0	288.9	288.9	297.2	311.4	406.4	555.7	"
1931-32	"	"	"	"	"	"	277.3	65.5	65.5	80.9	109.1	281.3	609.8	"
1932-33	"	"	"	"	"	"	273.7	"	"	75.1	94.3	191.6	573.3	"
1933-34	"	"	"	"	"	"	"	"	"	65.5	127.0	339.6	605.3	"
1934-35	"	"	"	"	"	"	"	"	"	"	83.5	187.2	488.1	"
1935-36	"	"	"	"	"	"	277.3	"	"	71.3	119.3	351.7	705.8	"
1936-37	"	"	"	"	"	"	377.7	263.6	263.6	272.5	287.5	388.3	546.6	"
1937-38	"	"	"	"	"	"	293.0	102.3	102.3	113.1	119.2	245.3	551.9	"
1938-39	"	"	"	"	"	"	288.0	92.7	92.7	109.3	132.6	399.3	705.8	"
1939-40	"	"	"	"	"	"	303.2	115.4	115.4	127.2	150.9	410.6	"	"
1940-41	"	"	"	"	"	"	345.5	202.1	202.1	212.2	229.3	344.2	524.5	"
1941-42	"	"	"	"	"	"	328.5	169.9	169.9	179.0	201.5	438.9	705.8	"
1942-43	"	"	"	"	"	"	333.0	178.4	178.4	192.2	221.1	289.2	653.1	"
1943-44	"	"	"	"	"	"	416.4	334.7	334.7	342.1	354.7	439.4	572.2	"
1944-45	"	"	"	"	"	"	384.9	277.3	277.3	278.6	279.4	493.7	705.8	"
1945-46	"	"	"	"	"	"	273.7	65.5	65.5	75.7	95.6	322.3	647.5	"
1946-47	"	"	"	"	"	"	"	"	"	77.0	102.0	314.0	629.6	"
1947-48	"	"	"	"	"	"	277.3	"	"	65.5	65.5	300.5	705.8	"
1948-49	"	"	"	"	"	"	371.1	251.0	251.0	256.9	277.0	434.3	"	"
1949-50	"	"	"	"	"	"	273.7	65.5	65.5	65.5	65.5	183.9	525.3	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	285.1	534.2	"
1951-52	"	"	"	"	"	"	277.3	"	"	"	67.4	92.4	255.0	"
1952-53	"	"	"	"	"	"	273.7	"	"	71.9	84.7	234.6	522.7	"
1953-54	"	"	"	"	"	"	"	"	"	73.2	84.1	237.1	547.6	"
1954-55	"	"	"	"	"	"	"	"	"	71.9	80.9	154.5	488.8	"
1955-56	"	"	"	"	"	"	277.3	"	"	65.5	84.7	266.6	585.4	"
1956-57	"	"	"	"	"	"	273.7	"	"	74.5	89.9	376.1	655.8	"
1957-58	"	"	"	"	"	"	"	"	"	77.0	96.3	359.4	705.8	"

TABLE 10
(English Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2001 - 02 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7806.2	7412.2	6971.4	6541.5	6090.2	5982.9	5465.5	4648.3	4201.0	3750.7	4425.6	6515.5	7814.6
1929-30	"	"	"	"	"	"	4491.4	3878.4	3357.4	3116.5	3423.6	4425.6	6515.5	"
1930-31	"	"	"	"	"	"	4959.1	4306.8	3727.2	3473.6	3627.8	4351.8	6515.5	"
1931-32	"	"	"	"	"	"	1668.6	1196.1	725.2	854.0	1312.5	2703.2	5874.1	"
1932-33	"	"	"	"	"	"	1567.8	1342.6	1284.6	1220.0	1483.8	2593.8	5524.8	"
1933-34	"	"	"	"	"	"	1481.7	898.5	260.4	355.0	941.4	2991.4	6372.6	"
1934-35	"	"	"	"	"	"	2799.7	2408.1	2155.7	2064.6	2097.7	3143.4	5902.1	"
1935-36	"	"	"	"	"	"	2764.0	2281.5	1957.2	1780.3	2026.9	3422.2	6490.7	"
1936-37	"	"	"	"	"	"	5848.3	5181.4	4524.7	4201.0	3750.7	4425.6	6515.5	"
1937-38	"	"	"	"	"	"	2535.9	2323.4	2065.2	2057.5	2307.2	3346.0	6148.9	"
1938-39	"	"	"	"	"	"	4613.8	3899.3	3242.5	3128.0	3103.0	4336.4	6515.5	"
1939-40	"	"	"	"	"	"	4117.0	3444.4	2972.0	2846.5	3194.4	4217.0	6515.5	"
1940-41	"	"	"	"	"	"	5580.4	4903.3	4391.5	4159.2	3733.8	4409.8	6499.1	"
1941-42	"	"	"	"	"	"	4515.9	3581.9	2745.8	2592.9	2478.5	3609.1	6515.5	"
1942-43	"	"	"	"	"	"	4375.8	3511.0	2757.3	2652.4	2670.3	3044.6	5390.4	"
1943-44	"	"	"	"	"	"	5982.9	5465.5	4648.3	4201.0	3750.7	4425.6	6515.5	"
1944-45	"	"	"	"	"	"	5490.4	4514.3	3486.1	3275.5	3117.5	4043.9	6348.8	"
1945-46	"	"	"	"	"	"	1481.7	1008.1	933.0	873.4	1220.0	2508.4	6010.9	"
1946-47	"	"	"	"	"	"	1889.5	1631.5	1600.5	1583.5	1943.7	3213.9	6176.7	"
1947-48	"	"	"	"	"	"	1674.8	1427.7	1371.6	1261.9	1484.9	2710.1	5989.1	"
1948-49	"	"	"	"	"	"	4170.5	3853.6	2838.1	2747.6	2749.4	4169.6	6515.5	"
1949-50	"	"	"	"	"	"	1976.0	1665.6	1610.1	1537.8	1756.4	2318.7	4925.2	"
1950-51	"	"	"	"	"	"	2191.4	2017.4	1886.0	1801.4	1872.1	2751.4	6297.4	"
1951-52	"	"	"	"	"	"	2741.4	2407.3	2232.0	2178.2	2461.5	3200.1	5729.3	"
1952-53	"	"	"	"	"	"	3407.4	3094.6	2540.9	2478.1	2384.8	3026.0	5997.0	"
1953-54	"	"	"	"	"	"	1481.7	850.8	760.7	718.5	1020.8	2150.3	4536.1	"
1954-55	"	"	"	"	"	"	2307.6	2146.4	2139.3	2071.9	2266.6	3123.3	5541.1	"
1955-56	"	"	"	"	"	"	1646.6	1289.7	1228.4	1164.9	1488.8	2882.2	5972.2	"
1956-57	"	"	"	"	"	"	1860.3	1534.4	1487.0	1422.3	1722.5	2863.4	6515.5	"
1957-58	"	"	"	"	"	"	1648.9	1160.5	1160.6	1187.6	1585.5	2724.2	6182.4	"

Note: The above ORC's are limited to individual project flood control rule curves.

TABLE 11
(English Units)
COMPARISON OF
RECENT ASSURED OPERATING PLAN STUDIES

	1997-98	1998-99	1999-00	2000-01	2001-02
MICA TARGET OPERATION					
(ksfd[xxxx.x] or cfs [xxxxx])					
AUG 15	3456.2	3456.2	3456.2	3486.2	3486.2
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	15000	11000	3428.2	3386.2	3396.2
NOV	19000	3256.2	3176.2	3056.2	20000
DEC	23000	2676.2	24000	25000	22000
JAN	24000	24000	25000	26000	24000
FEB	22000	22000	22000	23000	21000
MAR	19000	22000	21000	22000	22000
APR 15	106.2	86.2	156.2	26000	326.2
APR 30	0.0	56.2	106.2	106.2	56.2
MAY	10000	10000	10000	8000	10000
JUN	10000	10000	10000	8000	10000
JUL	3356.2	3406.2	3456.2	3456.2	3456.2
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (ksfd)					
1928 AUG 31	7814.6	7814.6	7814.6	7814.6	7806.2
1928 DEC	5755.8	6250.9	5618.4	5402.7	5310.4
1929 APR15	678.7	1676.3	1763.1	1597.9	1458.7
1929 JUL	6863.4	7005.8	6916.0	7116.1	7453.0
COMPOSITE 50-YR AVERAGE CANADIAN TREATY STORAGE CONTENT (ksfd)					
AUG 31	7212.1	7323.8	7295.4	7389.8	7412.3
DEC	5224.7	5584.3	5283.1	5157.8	5236.9
APR15	729.7	888.6	1424.0	1150.7	1135.3
JUL	7117.9	7110.7	7099.3	7273.7	7358.2
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-0.9	-5.1	-1.5	-0.3	0.2
U.S. Dependable Peaking Capacity	-4.0	27.0	0.0	-2.0	0.0
U.S. Avg. Annual Usable Secondary Energy	13.9	18.9	19.5	16.2	24.9
BCH Firm Energy	46.7	26.7	102.2	60.8	48.3
BCH Dependable Peaking Capacity	19.0	18.0	-3.0	-36.0	25.0
BCH Avg. Annual Usable Secondary Energy	-43.5	-18.5	-42.9	-43.6	-29.7
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	10223	10083	9793	10043	10422
AUG 31	10259	10203	9925	10125	10439
SEP	10121	9957	9630	10095	10434
OCT	10153	9963	9764	10046	10388
NOV	11452	11305	11297	11381	11626
DEC	12582	12787	12766	12836	13012
JAN	13477	13640	13725	13484	13382
FEB	12664	12638	12674	12765	12502
MAR	11948	11994	12113	11807	11667
APR 15	12643	11671	11099	11332	11187
APR 30	13437	12425	12672	13025	12575
MAY	16270	15701	17263	14347	14647
JUN	13781	14662	14699	11925	12590
JUL	10366	10594	9894	11275	10493
ANNUAL AVERAGE	12171	12117	12131	11850	11919

TABLE 1M
(Metric Units)
MICA PROJECT OPERATING CRITERIA
2001-02 ASSURED OPERATING PLAN

Period	End of Previous Period Arrow Storage Content (hm^3)	-------- Target Operation -------- Period Average Outflow (m^3/s)	End-of-Period Treaty Content 1/ (hm^3)	Minimum Outflow (m^3/s)	Minimum Treaty Storage Content 2/ (hm^3)
August 1-15	6361.2 - FULL	-	8529.3	424.75	0.0
	4036.9 - 6361.2	453.07			
	0.0 - 4036.9	736.24			
August 16-31	8318.4 - FULL	-	8634.5	424.75	0.0
	3547.6 - 8318.4	594.65			
	0.0 - 3547.6	736.24			
September	8465.2 - FULL	-	8634.5	283.17	0.0
	4428.3 - 8465.2	622.97			
	0.0 - 4428.3	764.55			
October	7572.2 - FULL	-	8309.1	283.17	0.0
	4966.6 - 7572.2	594.65			
	0.0 - 4966.6	792.87			
November	7095.1 - FULL	566.34		339.80	0.0
	6410.1 - 7095.1	622.97			
	2324.3 - 6410.1	679.60			
	0.0 - 2324.3	821.19			
December	7462.1 - FULL	622.97		594.65	506.4
	6141.0 - 7462.1	707.92			
	2446.6 - 6141.0	764.55			
	0.0 - 2446.6	821.19			
January	6287.8 - FULL	679.60		424.75	259.8
	6092.0 - 6287.8	651.29			
	3699.3 - 6092.0	736.24			
	0.0 - 3699.3	792.87			
February	3694.4 - FULL	594.65		424.75	0.0
	929.7 - 3694.4	651.29			
	893.0 - 929.7	594.65			
	0.0 - 893.0	792.87			
March	3143.9 - FULL	622.97		424.75	0.0
	1810.5 - 3143.9	566.34			
	1651.5 - 1810.5	679.60			
	0.0 - 1651.5	764.55			
April 1-15	4049.1 - FULL	-	798.1	368.12	0.0
	3547.6 - 4049.1	-	39.6		
	2446.6 - 3547.6	509.70			
	0.0 - 2446.6	-	0.0		
April 16-30	6801.5 - FULL	-	137.5	283.17	0.0
	6336.7 - 6801.5	-	0.0		
	1957.3 - 6336.7	283.17			
	0.0 - 1957.3	368.12			
May	734.0 - FULL	283.17		226.53	0.0
	721.7 - 734.0	226.53			
	474.6 - 721.7	396.44			
	0.0 - 474.6	622.97			
June	3131.6 - FULL	283.17		226.53	0.0
	2838.1 - 3131.6	226.53			
	1174.4 - 2838.1	339.80			
	0.0 - 1174.4	481.39			
July	4746.4 - FULL	-	8455.9	226.53	0.0
	4403.9 - 4746.4	481.39			
	0.0 - 4403.9	679.60			

Notes:

1/ A maximum outflow of 962.77 m^3/s will apply if the target end-of-period storage content @ Mica is less than 8634.5 hm^3 in every month except April, May, and June. For these periods, the maximum outflow is 906.14 m^3/s in April 1-15, 764.55 m^3/s in April 16-30, 849.50 m^3/s in May, and 934.46 m^3/s in June.

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

TABLE 3M
(Metric Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2001 - 02 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	8634.5	8634.5	8173.8	7606.5	7359.1	6348.4	4354.5	2988.3	2999.0	1280.8	499.8	1625.8	5656.5	8256.5
1929-30	8590.0	8511.0	7610.4	6306.6	4238.5	4098.5	1743.4	1384.3	1374.3	97.1	31.6	1594.9	4546.3	7266.2
1930-31	7629.0	7456.0	7321.2	6282.4	4225.5	3721.5	1655.9	1368.6	1336.3	161.2	2.7	0.0	1905.2	4166.8
1931-32	4204.7	3824.3	3697.3	3328.4	2501.2	430.8	24.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	8757.8	8746.6	8333.9	7883.9	7326.6	5616.4	3774.9	3309.3	3334.0	1999.6	817.2	2632.3	5887.7	8251.9
1929-30	8669.0	8579.5	7850.9	7827.7	6999.2	4202.0	1960.9	2076.7	1893.7	1042.5	696.5	1685.7	4407.3	7352.5
1930-31	7747.4	7565.4	7474.9	7572.2	7019.5	3817.4	1959.2	1449.6	1372.5	882.5	61.7	1191.0	4042.5	4156.3
1931-32	4213.8	4044.5	3931.7	3238.6	1705.0	1503.4	242.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	1726.8	1717.5	1627.0	1565.8	1155.5	1027.6	587.2	415.9	300.9	288.5	309.0	596.5	1268.8	1726.1
1929-30	1726.8	1675.4	1677.1	1615.2	1166.8	587.2	156.1	97.9	5.1	29.1	52.8	290.2	805.9	1281.3
1930-31	1435.2	1599.3	1614.8	1565.8	1151.4	587.9	149.5	97.9	4.4	21.0	20.3	171.3	753.3	1247.8
1931-32	1174.4	1101.0	1052.0	611.7	244.7	4.9	2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	19119.2	19098.6	18134.7	17056.2	15841.2	12992.4	8716.5	6713.5	6634.0	3568.9	1626.0	4854.5	12813.1	18234.5
1929-30	18985.9	18765.9	17138.4	15749.5	12404.5	8887.8	3860.5	3558.8	3273.1	1168.7	781.0	3570.8	9759.5	15900.0
1930-31	16811.6	16620.7	16410.8	15420.4	12396.4	8126.9	3764.6	2916.1	2713.3	1064.8	84.7	1362.3	6701.0	9570.9
1931-32	9592.9	8969.7	8681.0	7178.6	4450.9	1939.2	269.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 4M
(Metric Units)
MICA
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2001 - 02 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	2847.8	4228.2	5704.2	6140.5	6300.2	6340.6	6327.9	5135.4	3862.7	3300.5	2757.8	3217.5	6019.6	8634.5
VARIABLE REFILL CURVES (hm^3)														
1928-29							7285.0	6547.3	5928.6	5620.6	5499.7	5249.7	6925.8	8634.5
1929-30							4779.7	3945.1	3300.5	3040.1	3242.2	3750.9	6230.5	"
1930-31							5414.6	4601.8	3946.9	3632.7	3664.8	3800.1	6414.5	"
1931-32							2039.0	1723.1	1614.0	1376.5	1585.2	2555.2	5970.4	"
1932-33							1804.9	1575.6	1508.8	1266.4	1362.0	2301.5	5570.7	"
1933-34							1594.2	976.9	0.0	0.2	0.0	1680.1	6188.9	"
1934-35							3350.6	2889.4	2647.0	2424.1	2461.0	3010.5	5821.7	"
1935-36							3045.5	2529.5	2206.1	1926.5	2027.7	2924.2	6470.3	"
1936-37							7256.1	6468.1	5813.1	5478.7	5476.0	5283.2	7004.9	"
1937-38							2717.9	2443.7	2335.5	2107.7	2225.7	3106.2	6194.3	"
1938-39							4935.3	4290.1	3668.7	3418.4	3505.2	3857.6	6984.1	"
1939-40							4414.2	3661.6	3082.0	2817.3	2958.2	3350.9	6396.4	"
1940-41							5859.6	5098.0	4491.2	4223.8	4455.3	4730.5	6959.6	"
1941-42							4599.6	4139.2	3835.3	3541.7	3573.7	4048.4	6628.1	"
1942-43							4273.2	3944.9	3842.6	3590.1	3825.7	4654.4	6777.6	"
1943-44							7535.8	6692.2	6071.0	5743.9	5687.9	5545.5	7344.2	"
1944-45							7105.2	6416.5	5881.4	5602.0	5507.8	5315.2	7131.1	"
1945-46							1594.2	976.9	834.0	567.4	709.0	1804.6	5956.7	"
1946-47							"	1370.1	1327.3	1112.7	1304.3	2456.9	6129.2	"
1947-48							"	1194.7	1114.4	836.5	945.1	1952.1	5852.0	"
1948-49							5612.3	5283.2	5141.0	4886.1	4918.2	5348.0	7739.6	"
1949-50							2332.3	1968.0	1830.5	1563.1	1670.0	2498.0	5390.3	"
1950-51							2310.8	2063.2	2004.3	1780.1	1953.1	2792.1	6274.8	"
1951-52							3305.8	2954.0	2833.7	2551.1	2633.8	3521.1	6635.2	"
1952-53							3993.6	3685.8	3589.4	3336.9	3353.3	3904.0	6554.2	"
1953-54							1594.2	976.9	926.5	692.6	812.5	1745.2	5322.1	"
1954-55							3102.3	2863.0	2806.0	2585.8	2679.3	3339.1	5797.7	"
1955-56							1997.6	1715.1	1606.2	1345.4	1465.8	2540.1	6065.6	"
1956-57							2409.9	2109.7	2037.0	1805.6	1919.6	2752.7	6874.5	"
1957-58							2003.3	1734.6	1677.4	1459.4	1617.7	2497.7	6293.4	"
LIMITING RULE CURVE (hm^3)							1594.2	976.9	0.0	0.2				
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVES														
	84.95	84.95	84.95	84.95	84.95	84.95	84.95	566.34	566.34	566.34	622.97	622.97	622.97	622.97
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
98.68 km^3 --							84.95	283.17	283.17	283.17	339.80	566.34	566.34	566.34
117.18 km^3 --							84.95	84.95	84.95	226.53	283.17	339.80	424.75	509.70
135.69 km^3 --							84.95	84.95	84.95	226.53	283.17	339.80	424.75	509.70

TABLE 5M
(Metric Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2001 - 02 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	345.7	2600.5	5611.0	6913.4	7489.8	8628.9	8757.8	8049.8	6869.3	6356.3	5816.3	6729.4	8597.8	8757.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							7861.7	7550.9	7414.9	7322.2	8039.3	8441.7	8757.8	8757.8
1929-30							5423.4	4831.5	4273.2	3963.2	5016.0	6953.0	8755.4	*
1930-31							5932.8	5228.4	4615.8	4576.6	5515.6	6548.8	8757.8	*
1931-32							1886.3	1065.5	0.0	515.0	1359.1	3387.1	7106.6	*
1932-33							*	1670.0	1634.1	1718.5	2268.2	3808.1	6980.6	*
1933-34							*	1065.5	476.8	708.0	1992.5	4820.0	8248.2	*
1934-35							3094.7	2842.0	2809.9	2825.3	3263.5	4698.9	7443.0	*
1935-36							3418.6	2892.1	2422.1	2254.8	2639.4	4725.4	8537.2	*
1936-37							8645.1	8202.7	8066.9	7878.1	8617.4	8757.8	8757.8	*
1937-38							3156.4	2990.5	2975.3	3143.1	3645.4	4997.2	7861.7	*
1938-39							5756.1	5023.1	4316.8	4085.1	5240.6	6757.0	8757.8	*
1939-40							5102.4	4483.1	3907.0	3835.8	4688.4	6219.0	*	*
1940-41							7036.7	6404.0	6387.1	6634.9	8084.8	8757.8	*	*
1941-42							5953.1	5578.7	5310.6	5447.4	6435.3	7359.6	*	*
1942-43							6065.6	5735.1	5642.1	5914.4	7023.0	8290.1	*	*
1943-44							8757.8	8757.8	8757.8	8757.8	8757.8	8757.8	*	*
1944-45							7965.4	7846.7	7959.5	7961.5	8631.1	*	*	*
1945-46							1886.3	1450.3	1417.8	1510.5	2115.6	3793.9	7471.2	*
1946-47							2884.1	2523.2	2463.0	2601.7	3201.6	4762.3	7782.9	*
1947-48							2278.0	2138.1	2081.1	2090.6	2527.6	3992.6	7477.5	*
1948-49							3806.7	3678.7	4812.5	5175.3	6226.1	7532.6	8757.8	*
1949-50							2199.5	1946.8	1948.5	2039.0	2535.2	3849.0	6700.3	*
1950-51							2906.1	2767.6	2791.1	2799.6	3365.1	4692.3	8113.7	*
1951-52							3026.4	2775.4	2763.9	2788.1	3223.6	5137.4	8393.3	*
1952-53							3970.8	3725.2	3708.6	3793.9	4692.3	5825.6	8265.6	*
1953-54							1886.3	1065.5	934.6	1065.2	1596.7	3071.2	6672.9	*
1954-55							2323.5	2228.1	2267.8	2307.4	2815.3	4121.5	6617.8	*
1955-56							1886.3	1401.2	1377.2	1456.0	2030.7	3953.0	7514.7	*
1956-57							*	1484.1	1440.8	1491.9	2074.7	3563.5	8625.5	*
1957-58							*	1065.5	1114.7	1364.7	2081.8	3631.5	7798.5	*
LIMITING RULE CURVE (hm^3)							1886.3	1065.5	0.0	1.5				
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVES														
	141.58	141.58	141.58	141.58	141.58	141.58	141.58	1132.67	1132.67	1132.67	1415.84	1415.84	1444.16	1472.47
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
98.68 km^3 --							141.58	509.70	566.34	566.34	622.97	849.50	1189.31	1245.94
117.18 km^3 --							141.58	141.58	141.58	226.53	566.34	764.55	1047.72	1047.72
135.69 km^3 --							141.58	141.58	141.58	226.53	566.34	764.55	1047.72	1047.72

TABLE 6M
(Metric Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2001 - 02 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	279.6	453.1	615.3	690.4	733.2	760.6	785.6	712.2	640.5	621.4	602.4	880.8	1323.4	1726.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							1098.5	1074.8	1083.1	1100.5	1111.2	1199.8	1509.3	1726.8
1929-30							1094.4	1069.9	1077.5	1094.1	1139.1	1250.5	1537.2	"
1930-31							958.8	937.3	953.4	982.8	1009.2	1125.4	1509.3	"
1931-32							157.1	137.7	171.5	213.8	334.9	671.3	1294.5	"
1932-33							144.6	39.1	0.0	0.0	0.0	236.3	965.7	"
1933-34							"	155.8	202.6	259.6	447.0	818.6	1436.4	"
1934-35							404.4	401.0	442.6	471.9	528.7	790.3	1287.9	"
1935-36							298.2	281.4	298.0	322.0	384.6	723.2	1371.3	"
1936-37							971.1	947.1	959.6	976.7	989.6	1106.8	1465.8	"
1937-38							330.0	328.6	357.2	396.8	486.1	808.1	1354.7	"
1938-39							596.7	588.4	609.9	637.1	689.0	909.6	1467.2	"
1939-40							556.1	561.0	600.4	651.0	706.3	914.8	1439.3	"
1940-41							756.7	753.8	783.4	837.0	909.9	1104.2	1497.3	"
1941-42							666.5	669.1	699.5	731.3	789.8	1024.1	1448.1	"
1942-43							650.1	637.6	661.8	688.2	773.4	1079.7	1435.2	"
1943-44							1137.9	1127.4	1147.7	1170.2	1184.6	1280.8	1583.2	"
1944-45							935.1	925.5	947.6	970.3	986.2	1106.8	1480.4	"
1945-46							144.6	39.1	30.8	59.0	160.3	538.5	1278.3	"
1946-47							"	98.4	125.5	159.8	265.7	643.9	1309.4	"
1947-48							225.3	217.3	247.6	273.3	355.0	685.8	1334.6	"
1948-49							784.6	764.3	780.0	799.3	862.7	1112.2	1583.9	"
1949-50							302.6	284.8	306.8	328.6	404.2	707.3	1198.1	"
1950-51							144.6	105.0	143.1	166.9	269.1	623.1	1273.9	"
1951-52							374.8	360.6	390.2	415.7	495.2	831.1	1384.3	"
1952-53							372.1	358.7	386.3	413.5	488.1	778.0	1301.8	"
1953-54							144.6	39.1	0.0	0.0	88.3	444.5	1132.3	"
1954-55							219.9	211.1	238.8	269.4	347.9	654.7	1141.3	"
1955-56							144.6	39.1	22.0	48.7	146.1	558.6	1268.3	"
1956-57							255.2	231.2	252.0	279.4	369.2	689.5	1425.6	"
1957-58							144.6	39.1	47.5	81.5	179.6	535.8	1307.7	"
LIMITING RULE CURVE (hm^3)							144.6	39.1	0.0	0.0				

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVES														
	2.83	2.83	2.83	2.83	2.83	2.83	2.83	42.48	42.48	42.48	42.48	42.48	56.63	56.63
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
98.68 km^3 --							2.83	2.83	2.83	2.83	42.48	50.97	76.46	82.12
117.18 km^3 --							2.83	2.83	2.83	2.83	11.33	16.99	76.46	82.12
135.69 km^3 --							2.83	2.83	2.83	2.83	11.33	16.99	76.46	82.12

TABLE 7M
(Metric Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2001 - 02 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8634.5	8634.5	8634.5	8387.9	8387.9	8387.9	8283.5	8189.3	8085.0	8085.0	8085.0	8242.8	8435.6	8634.5
1929-30	"	"	"	"	"	"	8202.5	8035.6	7850.4	7850.4	7850.4	8075.5	8350.7	"
1930-31	"	"	"	"	"	"	8387.9	8387.9	8387.9	8387.9	8387.9	8458.6	8545.2	"
1931-32	"	"	"	"	"	"	7598.4	6858.3	6068.8	6068.8	6068.8	6805.2	7705.8	"
1932-33	"	"	"	"	"	"	7588.6	6868.1	"	"	"	"	"	"
1933-34	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1934-35	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1935-36	"	"	"	"	"	"	7598.4	6858.3	"	"	"	"	"	"
1936-37	"	"	"	"	"	"	8148.6	7932.6	7693.3	7693.3	7693.3	8130.8	8314.5	"
1937-38	"	"	"	"	"	"	7588.6	6868.1	6068.8	6068.8	6068.8	6805.2	7705.8	"
1938-39	"	"	"	"	"	"	7814.0	7294.3	6720.3	6720.3	6720.3	7269.8	7941.7	"
1939-40	"	"	"	"	"	"	8010.9	7659.1	7282.1	7282.1	7282.1	7670.3	8145.0	"
1940-41	"	"	"	"	"	"	8387.9	8387.9	8387.9	8387.9	8387.9	8458.6	8545.2	"
1941-42	"	"	"	"	"	"	7588.6	6868.1	6068.8	6068.8	6068.8	6805.2	7705.8	"
1942-43	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1943-44	"	"	"	"	"	"	8387.9	8387.9	8387.9	8387.9	8387.9	8458.6	8545.2	"
1944-45	"	"	"	"	"	"	7812.2	7291.4	6715.9	6715.9	6715.9	7266.4	7940.0	"
1945-46	"	"	"	"	"	"	7588.6	6868.1	6068.8	6068.8	6068.8	6805.2	7705.8	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1947-48	"	"	"	"	"	"	7598.4	6858.3	"	"	"	"	"	"
1948-49	"	"	"	"	"	"	7588.6	6868.1	"	"	"	"	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1951-52	"	"	"	"	"	"	7598.4	6858.3	"	"	"	"	"	"
1952-53	"	"	"	"	"	"	7588.6	6868.1	"	"	"	"	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	"	"	"
1955-56	"	"	"	"	"	"	7598.4	6858.3	"	"	"	6594.8	7762.3	"
1956-57	"	"	"	"	"	"	7588.6	6868.1	"	"	"	6805.2	7705.8	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	"	"	"

TABLE 8M
(Metric Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2001 - 02 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8757.8	8757.8	8757.8	8449.6	8449.6	7524.3	7524.3	7524.3	7524.3	7556.3	7611.9	7916.7	8757.8	8757.8
1929-30	"	"	"	"	"	"	7335.6	7164.4	6975.7	7022.0	7102.2	7542.4	"	"
1930-31	"	"	"	"	"	"	7524.3	7524.3	7524.3	7556.3	7611.9	7916.7	"	"
1931-32	"	"	"	"	"	"	5802.4	4190.3	2466.9	2485.7	2756.3	5442.5	"	"
1932-33	"	"	"	"	"	"	5782.5	4208.6	"	2466.9	2536.1	4310.2	7424.2	"
1933-34	"	"	"	"	"	"	"	"	"	"	4366.9	5694.2	8757.8	"
1934-35	"	"	"	"	"	"	"	"	"	"	2466.9	4222.1	7424.2	"
1935-36	"	"	"	"	"	"	5802.4	4190.3	"	2617.9	3360.4	5222.3	8757.8	"
1936-37	"	"	"	"	"	"	7195.0	6896.5	6566.9	6623.9	6742.3	7991.1	"	"
1937-38	"	"	"	"	"	"	5782.5	4208.6	2466.9	2649.4	3127.5	4480.0	7700.9	"
1938-39	"	"	"	"	"	"	6323.2	5238.9	4037.6	4207.7	4509.6	6511.1	8757.8	"
1939-40	"	"	"	"	"	"	6834.1	6188.4	5498.2	5595.9	5824.1	7127.9	"	"
1940-41	"	"	"	"	"	"	7524.3	7524.3	7524.3	7556.3	7611.9	7916.7	"	"
1941-42	"	"	"	"	"	"	5782.5	4208.6	2466.9	2605.4	2813.1	4731.7	"	"
1942-43	"	"	"	"	"	"	"	"	"	2718.7	3234.4	3523.8	5845.2	"
1943-44	"	"	"	"	"	"	7524.3	7524.3	7524.3	7556.3	7611.9	7916.7	8757.8	"
1944-45	"	"	"	"	"	"	6319.3	5230.8	4025.9	4091.9	4267.1	5795.5	8190.0	"
1945-46	"	"	"	"	"	"	5782.5	4208.6	2466.9	2624.2	3039.4	5385.9	8757.8	"
1946-47	"	"	"	"	"	"	"	"	"	2630.6	3328.8	5253.8	"	"
1947-48	"	"	"	"	"	"	5802.4	4190.3	"	2536.1	2894.8	5423.6	"	"
1948-49	"	"	"	"	"	"	5782.5	4208.6	"	2800.4	3366.5	6103.0	"	"
1949-50	"	"	"	"	"	"	"	"	"	2466.9	2466.9	2725.0	"	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	3316.4	8166.5	"
1951-52	"	"	"	"	"	"	5802.4	4190.3	"	2617.9	3291.2	4385.8	7373.8	"
1952-53	"	"	"	"	"	"	5782.5	4208.6	"	2586.5	2869.6	3611.9	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	2775.2	3983.1	4643.6	"
1954-55	"	"	"	"	"	"	"	"	"	2630.6	2668.3	4045.9	7889.8	"
1955-56	"	"	"	"	"	"	5802.4	4190.3	"	2466.9	2976.5	4870.2	7323.7	"
1956-57	"	"	"	"	"	"	5782.5	4208.6	"	2636.9	2995.4	6486.9	8757.8	"
1957-58	"	"	"	"	"	"	"	"	"	2561.3	2913.7	5486.5	"	"

TABLE 9M
(Metric Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2001 - 02 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	1726.8	1726.8	1726.8	1726.8	1726.8	1233.3	1023.4	833.8	833.8	851.7	882.0	1085.6	1405.3	1726.8
1929-30	"	"	"	"	"	"	999.2	788.0	788.0	806.9	838.7	1052.8	1388.9	"
1930-31	"	"	"	"	"	"	956.6	706.8	706.8	727.1	761.9	994.3	1359.6	"
1931-32	"	"	"	"	"	"	678.4	160.3	160.3	197.9	266.9	688.2	1491.9	"
1932-33	"	"	"	"	"	"	669.6	"	"	183.7	230.7	468.8	1402.6	"
1933-34	"	"	"	"	"	"	"	"	"	160.3	310.7	830.9	1480.9	"
1934-35	"	"	"	"	"	"	"	"	"	"	204.3	458.0	1194.2	"
1935-36	"	"	"	"	"	"	678.4	"	"	174.4	291.9	860.5	1726.8	"
1936-37	"	"	"	"	"	"	924.1	644.9	644.9	666.7	703.4	950.0	1337.3	"
1937-38	"	"	"	"	"	"	716.9	250.3	250.3	276.7	291.6	600.2	1350.3	"
1938-39	"	"	"	"	"	"	704.6	226.8	226.8	267.4	324.4	976.9	1726.8	"
1939-40	"	"	"	"	"	"	741.8	282.3	282.3	311.2	369.2	1004.6	"	"
1940-41	"	"	"	"	"	"	845.3	494.5	494.5	519.2	561.0	842.1	1283.2	"
1941-42	"	"	"	"	"	"	803.7	415.7	415.7	437.9	493.0	1073.8	1726.8	"
1942-43	"	"	"	"	"	"	814.7	436.5	436.5	470.2	540.9	707.6	1597.9	"
1943-44	"	"	"	"	"	"	1018.8	818.9	818.9	837.0	867.8	1075.0	1399.9	"
1944-45	"	"	"	"	"	"	941.7	678.4	678.4	681.6	683.6	1207.9	1726.8	"
1945-46	"	"	"	"	"	"	669.6	160.3	160.3	185.2	233.9	788.5	1584.2	"
1946-47	"	"	"	"	"	"	"	"	"	188.4	249.6	768.2	1540.4	"
1947-48	"	"	"	"	"	"	678.4	"	"	160.3	160.3	735.2	1726.8	"
1948-49	"	"	"	"	"	"	907.9	614.1	614.1	628.5	677.7	1062.6	"	"
1949-50	"	"	"	"	"	"	669.6	160.3	160.3	160.3	160.3	449.9	1285.2	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	697.5	1307.0	"
1951-52	"	"	"	"	"	"	678.4	"	"	"	164.9	226.1	623.9	"
1952-53	"	"	"	"	"	"	669.6	"	"	175.9	207.2	574.0	1278.8	"
1953-54	"	"	"	"	"	"	"	"	"	179.1	205.8	580.1	1339.8	"
1954-55	"	"	"	"	"	"	"	"	"	175.9	197.9	378.0	1195.9	"
1955-56	"	"	"	"	"	"	678.4	"	"	160.3	207.2	652.3	1432.2	"
1956-57	"	"	"	"	"	"	669.6	"	"	182.3	219.9	920.2	1604.5	"
1957-58	"	"	"	"	"	"	"	"	"	188.4	235.6	879.3	1726.8	"

TABLE 10M
(Metric Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2001 - 02 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.2	19098.6	18134.7	17056.2	16004.4	14900.3	14637.8	13371.9	11372.5	10278.2	9176.5	10827.7	15940.8	19119.2
1929-30	"	"	"	"	"	"	10988.7	9488.9	8214.2	7624.8	8376.2	10827.7	15940.8	"
1930-31	"	"	"	"	"	"	12132.9	10537.0	9119.0	8498.5	8875.8	10647.1	15940.8	"
1931-32	"	"	"	"	"	"	4082.4	2926.4	1774.3	2089.4	3211.2	6613.6	14371.6	"
1932-33	"	"	"	"	"	"	3835.8	3284.8	3142.9	2984.9	3630.3	6346.0	13517.0	"
1933-34	"	"	"	"	"	"	3625.1	2198.3	637.1	868.5	2303.2	7318.8	15591.2	"
1934-35	"	"	"	"	"	"	6849.7	5891.7	5274.1	5051.3	5132.2	7690.6	14440.1	"
1935-36	"	"	"	"	"	"	6762.4	5581.9	4788.5	4355.7	4959.0	8372.8	15880.1	"
1936-37	"	"	"	"	"	"	14308.5	12676.8	11070.1	10278.2	9176.5	10827.7	15940.8	"
1937-38	"	"	"	"	"	"	6204.3	5684.4	5052.7	5033.9	5644.8	8186.3	15043.9	"
1938-39	"	"	"	"	"	"	11288.1	9540.0	7933.1	7653.0	7591.8	10609.4	15940.8	"
1939-40	"	"	"	"	"	"	10072.7	8427.1	7271.3	6964.2	7815.4	10317.3	15940.8	"
1940-41	"	"	"	"	"	"	13653.0	11996.4	10744.2	10175.9	9135.1	10789.0	15900.7	"
1941-42	"	"	"	"	"	"	11048.6	8763.5	6717.9	6343.8	6063.9	8830.0	15940.8	"
1942-43	"	"	"	"	"	"	10705.8	8590.0	6746.0	6489.4	6533.2	7448.9	13188.2	"
1943-44	"	"	"	"	"	"	14637.8	13371.9	11372.5	10278.2	9176.5	10827.7	15940.8	"
1944-45	"	"	"	"	"	"	13432.8	11044.7	8529.1	8013.8	7627.3	9893.8	15533.0	"
1945-46	"	"	"	"	"	"	3625.1	2466.4	2282.7	2136.9	2984.9	6137.1	14706.3	"
1946-47	"	"	"	"	"	"	4622.9	3991.6	3915.8	3874.2	4755.5	7863.1	15111.9	"
1947-48	"	"	"	"	"	"	4097.6	3493.0	3355.8	3087.4	3633.0	6630.5	14652.9	"
1948-49	"	"	"	"	"	"	10203.5	9428.2	6943.7	6722.3	6726.7	10201.3	15940.8	"
1949-50	"	"	"	"	"	"	4834.5	4075.1	3939.3	3762.4	4297.2	5672.9	12050.0	"
1950-51	"	"	"	"	"	"	5361.5	4935.8	4614.3	4407.3	4580.3	6731.6	15407.2	"
1951-52	"	"	"	"	"	"	6707.1	5889.7	5460.8	5329.2	6022.3	7829.4	14017.3	"
1952-53	"	"	"	"	"	"	8336.5	7571.2	6216.6	6062.9	5834.7	7403.4	14672.3	"
1953-54	"	"	"	"	"	"	3625.1	2081.6	1861.1	1757.9	2497.5	5260.9	11098.0	"
1954-55	"	"	"	"	"	"	5645.8	5251.4	5234.0	5069.1	5545.5	7641.5	13556.9	"
1955-56	"	"	"	"	"	"	4028.6	3155.4	3005.4	2850.0	3642.5	7051.6	14611.6	"
1956-57	"	"	"	"	"	"	4551.4	3754.1	3638.1	3479.8	4214.3	7005.6	15940.8	"
1957-58	"	"	"	"	"	"	4034.2	2839.3	2839.5	2905.6	3879.1	6665.0	15125.9	"

Note: The above ORC's are limited to individual project flood control rule curves.

TABLE 11M
(Metric Units)
COMPARISON OF
RECENT ASSURED OPERATING PLAN STUDIES

	1997-98	1998-99	1999-00	2000-01	2001-02
MICA TARGET OPERATION					
(hm³ [xxxx.x] or m³/s [xxxx.xx])					
AUG 15	8455.9	8455.9	8455.9	8529.3	8529.3
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	424.75	311.49	8387.4	8284.7	8309.1
NOV	538.02	7966.6	7770.9	7477.3	566.34
DEC	651.29	6547.6	679.60	707.92	622.97
JAN	679.60	679.60	707.92	736.24	679.60
FEB	622.97	622.97	622.97	651.29	594.65
MAR	538.02	622.97	594.65	622.97	622.97
APR 15	259.8	210.9	382.2	736.24	798.1
APR 30	0.0	137.5	259.8	259.8	137.5
MAY	283.17	283.17	283.17	226.53	283.17
JUN	283.17	283.17	283.17	226.53	283.17
JUL	8211.3	8333.6	8455.9	8455.9	8455.9
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (hm³)					
1928 AUG 31	19119.2	19119.2	19119.2	19119.2	19098.6
1928 DEC	14082.1	15293.5	13746.0	13218.2	12992.4
1929 APR15	1660.5	4101.2	4313.6	3909.4	3568.9
1929 JUL	16792.0	17140.4	16920.7	17410.3	18234.5
COMPOSITE 50-YR AVERAGE CANADIAN TREATY STORAGE CONTENT (hm³)					
AUG 31	17645.1	17918.4	17848.9	18079.9	18134.9
DEC	12782.8	13662.5	12925.6	12619.1	12812.6
APR15	1785.3	2174.0	3484.0	2815.3	2777.6
JUL	17414.7	17397.0	17369.1	17795.8	18002.6
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-0.9	-5.1	-1.5	-0.3	0.2
U.S. Dependable Peaking Capacity	-4.0	27.0	0.0	-2.0	0.0
U.S. Avg. Annual Usable Secondary Energy	13.9	18.9	19.5	16.2	24.9
BCH Firm Energy	46.7	26.7	102.2	60.8	48.3
BCH Dependable Peaking Capacity	19.0	18.0	-3.0	-36.0	25.0
BCH Avg. Annual Usable Secondary Energy	-43.5	-18.5	-42.9	-43.6	-29.7
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	10223	10083	9793	10043	10422
AUG 31	10259	10203	9925	10125	10439
SEP	10121	9957	9630	10095	10434
OCT	10153	9963	9764	10046	10388
NOV	11452	11305	11297	11381	11626
DEC	12582	12787	12766	12836	13012
JAN	13477	13640	13725	13484	13382
FEB	12664	12638	12674	12765	12502
MAR	11948	11994	12113	11807	11667
APR 15	12643	11671	11099	11332	11187
APR 30	13437	12425	12672	13025	12575
MAY	16270	15701	17263	14347	14647
JUN	13781	14662	14699	11925	12590
JUL	10366	10594	9894	11275	10493
ANNUAL AVERAGE	12171	12117	12131	11850	11919

Appendix A1
(English Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Canadian Projects					
Mica (1890)	Minimum Flow	3000 cfs			In place in AOP79, AOP80, AOP84
Arrow (1831)	Minimum Flow	5000 cfs			In place in AOP79, AOP80, AOP84
	Draft Limit		1 ft/day		
Duncan (1681)	Minimum Flow	100 cfs			In place in AOP79, AOP80, AOP84
	Maximum Flow	10000 cfs			In place in AOP79, AOP80, AOP84
	Draft Limit		1 ft/day		
	Other			Operate to meet IJC orders for Corra Linn	CRTOC agreement on procedures to implement 1938 IJC order
Base System					
Hungry Horse (1530)	Minimum Flow	400 cfs		Minimum project discharge	In place in AOP79, AOP80, AOP84
	Maximum Flow			None	
	Minimum Content			None	
	Other			No VECC limit	VECC limit not in place in AOP79
Kerr (1510)	Minimum Flow	1500 cfs		All periods	In place in AOP80, AOP84
	Maximum Flow			None	
	Minimum Content	614.7 ksfd 426.3 ksfd	2893.0 ft 2890.0 ft	Jun - Sep May	MPC 2-1-92, PNCA submittal similar operation, Jun-Aug 15, in AOP80
		0.0 ksfd	2883.0 ft	Empty Apr 15	FERC, AOP80
	Other	0.0 ksfd		Conditions permitting, should be on or about, empty Mar and Apr 15	FERC, AOP80

Appendix A1
(English Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Thompson Falls (1490)				None Noted	
Noxon Rapids (1480)	Minimum Content				
	For Step I:	116.3 ksfd	2331.0 ft	May - Aug 31,	In place in AOP84,
		112.3 ksfd	2330.0 ft	Sep - Jan,	similar operation in
		78.7 ksfd	2321.0 ft	Feb,	AOP80
		26.5 ksfd	2305.0 ft	Mar,	
		0.0 ksfd	2295.0 ft	Empty Apr 15, Apr 30, and for end of CP	
	Minimum & Maximum Content				
	For Step II & III:	116.3 ksfd	2331.0 ft	All periods	In place in AOP79, AOP84
Cabinet Gorge (1475)				None Noted	
Albeni Falls (1465)	Minimum Flow	4000 cfs		All periods	In place in AOP80, AOP84
	Minimum Content	(Dec may fill on restriction, note below)			
		582.4 ksfd	2062.5 ft	Jun - Aug 31	In place in AOP80,
		465.7 ksfd	2060.0 ft	Sep	AOP84
		190.4 ksfd	2054.0 ft	Oct	
		57.6 ksfd	2051.0 ft	Nov-Apr 15	
		190.4 ksfd	2054.0 ft	Apr 30 (empty at end of CP)	
		279.0 ksfd	2056.0 ft	May	
	For Step I & II:	Optimum to run CP & LT to Jul-Oct SMINs.			
	For Step III:	Keep full at beginning of CP. Optimum to run higher than SMIN in CP & LT (except when occasionally drafting below SMIN to meet load).			
		439.5 ksfd	2059.4 ft	May	
		582.4 ksfd	2062.5 ft	Sep	
		465.7 ksfd	2060.0 ft	Oct	
	Kokanee Spawning	Draft no more than 1 ft below Nov 20 elevation through Dec 31. If project fills, draft no more than 0.5 ft. Dec 31 - Mar 31 operate between SMIN and URC within above noted draft limits.			In place before AOP80 and supported by minimum contents noted above.
	Other Spill	50 cfs		All periods	

Appendix A1
(English Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Box Canyon (1460)				None Noted	
Grand Coulee (1280)	Minimum Flow	30000 cfs		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	843.9 ksfd 0.0 ksfd	1240.0 ft 1208.0 ft	May Empty at end of CP	Retain as a power operation (for pumping)
	Step II & III only	2557.1 ksfd	1288.0 ft	Aug-Nov	
	Maximum Content Step I only:		2 ft 3 ft	Operating room Sep - Nov Operating room Dec - Feb	In place in AOP89. Retain as a power operation
	Draft Limit		1.3 ft/day 1.5 ft/day	(bank sloughage) (Constraint submitted as 1.5 ft/day interpreted as 1.3 ft/day mo. ave.)	
Chief Joseph (1270)	Other Spill	500 cfs		All periods	
Wells (1220)	Other Spill	1200 cfs		All periods	With fish ladder
	Fish Spill			Removed	
Rocky Reach (1200)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	200 cfs		Aug 31 - Apr 15 (leakage)	
	Fish Spill			Removed	
Rock Island (1170)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Fish Spill			Removed	
Wanapum (1165)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	2200 cfs		All periods	With fish ladder
	Fish Spill			Removed	
Priest Rapids (1160)	Minimum Flow			Limit removed	
	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	2200 cfs		All periods	With fish ladder
	Fish Spill			Removed	

Appendix A1
(English Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Brownlee (767)	Minimum Flow	5000 cfs		All periods	In place in AOP79, AOP80, AOP84
	Power Operation			Agree to use "old" power operation (first codes) provided by IPC and used in AOP since AOP97. More recent information for BRN from IPC operates the project variably (depending on inflow estimates) and for flow augmentation and water temperature control (S. Davis communication with IPC, 1992 and 1994).	2-1-91 PNCA submittal
Oxbow (765)	Other Spill	100 cfs		All periods	
Ice Harbor (502)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	740 cfs		All periods	
	Incremental Spill			None	
	Fish Spill			None	
	Minimum Flow			None	
	Other	204.8 ksfd	440.0 ft	Run at all periods	
McNary (488)	Other Spill	3475 cfs		All periods	
	Incremental Spill			None	
John Day (440)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	800 cfs		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
	Minimum Flow	50000 cfs 12500 cfs		Mar - Nov Dec - Feb	
	Other	190.0 ksfd	265.0 ft	Use JDA as a run-of-river plant.	

Appendix A1
(English Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
The Dalles (365)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	1300 cfs		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
	Minimum Flow	50000 cfs 12500 cfs		Mar - Nov Dec - Feb	
Bonneville (320)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	8040 cfs		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
Kootenay Lake (Corra Linn (1665))	Minimum Flow	5000 cfs		All periods	BCHydro agreements 1969
	Other			Operate to IJC orders.	CRTOC agreement on procedures to implement 1938 IJC order
Chelan (1210)	Minimum Flow	50 cfs		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	308.5 ksfd	1098.0 ft	Jul - Sep (except as needed to empty at end of critical period).	In place in AOP79, AOP80, AOP84
Couer d'Alene L (1341)	Minimum Flow	50 cfs		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	112.5 ksfd	2128.0 ft	May - Aug	In place in AOP79

Appendix A1
(English Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Other Major Step I Projects					
Libby (1760) Without sturgeon	Minimum Flow	4000 cfs		All periods	In place in AOP79 and AOP86
	Other Spill	200 cfs		All periods	
	Minimum Content	By contract year: Aug-Jul i.e., 1929 = Aug 1928 - Jul 1929			
		776.9 ksfd	2363.0 ft	1929 Dec	2-1-93 PNCA submittal, in place in AOP99 (w/o sturgeon)
		676.5 ksfd	2355.0 ft	1929 Jan	
		603.6 ksfd	2349.0 ft	1929 Feb	
		2147.7 ksfd	2443.0 ft	1929 Jul	
		652.0 ksfd	2353.0 ft	1930 Dec	
		433.2 ksfd	2334.0 ft	1930 Jan	
		389.3 ksfd	2330.0 ft	1930 Feb	
		348.5 ksfd	2326.0 ft	1930 Mar	
		297.4 ksfd	2321.0 ft	1930 Apr 15	
		444.2 ksfd	2335.0 ft	1930 Apr 30	
		499.1 ksfd	2340.0 ft	1930 May	
		1344.6 ksfd	2402.0 ft	1930 Jun	
		1771.9 ksfd	2425.0 ft	1930 Jul	
		317.8 ksfd	2323.0 ft	1931 Dec	
		192.2 ksfd	2310.0 ft	1931 Jan	
		103.1 ksfd	2300.0 ft	1931 Feb-Apr 30	
		192.2 ksfd	2310.0 ft	1931 May	
		676.5 ksfd	2355.0 ft	1931 Jun	
		868.0 ksfd	2370.0 ft	1931 Jul	
		174.4 ksfd	2308.0 ft	1932 Dec	
		103.1 ksfd	2300.0 ft	1932 Jan	
		0.0 ksfd	2287.0 ft	Empty at end of CP***	
		776.9 ksfd	2363.0 ft	All Dec	
		July 1930 - No more than 373.1 ksfd lower than July 1929 July 1931 - No more than 857.1 ksfd lower than July 1930 March - Implement PNCA 6(c)2(c)			2-1-94 PNCA submittal, in place in AOP00 and AOP01 (w/o sturgeon)
	Maximum Summer Draft		5 ft		
	Other			Operate to meet IJC orders for Corra Linn	CRTOC agreement on procedures to implement 1938 IJC order

Appendix A1
(English Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements				Source
Dworshak (535)	Minimum Flow	1500 cfs			All periods	2-1-96 PNCA submittal
	Maximum Flow	14000 cfs			All periods	2-1-96 PNCA submittal
		25000 cfs			(up to for flood control)	
	Minimum Elev	395.8 ksfd		1520.0 ft	SMIN Apr-Aug 31	
	Start 4 yr CP at: End 4 yr CP at:	392.6 ksfd 330.3 ksfd		1519.5 ft 1509.7 ft	(1/2 ft lower) (19.5 ft higher)	
	Other	Run on minimum flow or flood control observing maximum & minimum flow requirements all periods except to meet LWG outflows:				2-1-96 PNCA submittal
	LWG Target Flow	85000 cfs 50000 cfs	to to	100000 cfs 55000 cfs	Apr 10 - Jun 20, and Jun 21 - Aug 31.	
	Other Spill	100 cfs				
Lower Granite (520)	Bypass Date				None	
	Other Spill	670 cfs			All periods	
	Incremental Spill				Removed	
	Fish Spill			16.0% 40.0% 26.7%	Apr 15 Apr 30 & May Jun	2-1-96 PNCA submittal
	Maximum Spill	20000 cfs				
	Minimum Flow	11500 cfs			Mar-Nov	
	Other	221.8 ksfd 245.8 ksfd		733 ft 738 ft	Run at (MOP) Apr 30 - Oct. Run at all other periods.	
Little Goose (518)	Bypass Date				None	
	Other Spill	630 cfs			All periods	
	Incremental Spill				Removed	
	Fish Spill			16.0% 40.0% 26.7%	Apr 15 Apr 30 & May Jun	2-1-96 PNCA submittal
	Maximum Spill	20000 cfs				
	Minimum Flow	11500 cfs			Mar - Nov	
	Other	260.2 ksfd 285.0 ksfd		633.0 ft 638.0 ft	Run at Apr 15 - Aug 31. Run at all other periods.	

Appendix A1
(English Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Lower Monumental (504)	Bypass Date			A bypass date of 2010 was assumed.	
	Other Spill	750 cfs		All periods	
	Fish Spill		16.2% 40.5% 27.0%	Apr 15 Apr 30 & May Jun	2-1-96 PNCA submittal
	Maximum Spill	15000 cfs			
	Minimum Flow	11500 cfs		Mar-Nov	
	Other	179.5 ksfd 190.1 ksfd	537.0 ft 540.0 ft	Run at Apr 15 - Aug 31. Run at all other periods.	
Cushman (2206)	Other Spill	100 cfs			
White River (2160)	Other Spill	130 cfs		All periods	
Round Butte (390)	Other Spill	200 cfs		All periods	

Appendix A2
(Metric Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Canadian Projects					
Mica (1890)	Minimum Flow	84.95 m^3/s			In place in AOP79, AOP80, AOP84
Arrow (1831)	Minimum Flow	141.58 m^3/s			In place in AOP79, AOP80, AOP84
	Draft Limit		0.30 m/day		
Duncan (1681)	Minimum Flow	2.83 m^3/s			In place in AOP79, AOP80, AOP84
	Maximum Flow	283.17 m^3/s			In place in AOP79, AOP80, AOP84
	Draft Limit		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 (1530)	Minimum Flow	11.33 m^3/s		Minimum project discharge	In place in AOP79, AOP80, AOP84
	Maximum Flow			None	
	Minimum Content			None	
	Other			No VECC limit	VECC limit not in place in AOP79
Kerr (1510)	Minimum Flow	42.47 m^3/s		All periods	In place in AOP80, AOP84
	Maximum Flow			None	
	Minimum Content	1503.9 hm^3 1043.0 hm^3	881.79 m 880.87 m	Jun - Sep May	MPC 2-1-92, PNCA submittal similar operation, Jun-Aug 15, in AOP80
		0.0 hm^3	878.74 m	Empty Apr 15	FERC, AOP80

Appendix A2
(Metric Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
	Other	0.0 hm^3		Conditions permitting, should be on or about, empty Mar and Apr 15	FERC, AOP80
Thompson Falls				None Noted	
Noxon Rapids (1480)	Minimum Content For Step I:	284.5 hm^3	710.49 m	May - Aug 31,	In place in AOP84, similar operation in AOP80
		274.8 hm^3	710.18 m	Sep - Jan,	
		192.5 hm^3	707.44 m	Feb,	
		64.8 hm^3	702.56 m	Mar,	
		0.0 hm^3	699.52 m	Empty Apr 15, Apr 30, and for end of CP	
	Minimum & Maximum Content For Step II & III:	284.5 hm^3	710.49 m	All periods	In place in AOP79, AOP84
Cabinet Gorge (1475)				None Noted	
Albeni Falls (1465)	Minimum Flow	113.27 m^3/s		All periods	In place in AOP80, AOP84
	Minimum Content	(Dec may fill on restriction, note below)			
		1424.9 hm^3	628.65 m	Jun - Aug 31	In place in AOP80, AOP84
		1139.4 hm^3	627.89 m	Sep	
		465.8 hm^3	626.06 m	Oct	
		140.9 hm^3	625.14 m	Nov-Apr 15	
		465.8 hm^3	626.06 m	Apr 30 (empty at end of CP)	
		682.6 hm^3	626.67 m	May	
	For Step I & II:	Optimum to run CP & LT to Jul-Oct SMINs.			
	For Step III:	Keep full at beginning of CP. Optimum to run higher than SMIN in CP & LT (except when occasionally drafting below SMIN to meet load).			
		1075.3 hm^3	627.71 m	May	
		1424.9 hm^3	628.65 m	Sep	
		1139.4 hm^3	627.89 m	Oct	
	Kokanee Spawning	Draft no more than 0.30 m below Nov 20 elevation through Dec 31. If project fills, draft no more than 0.15 m. Dec 31 - Mar 31 operate between SMIN and URC within above noted draft limits.			In place before AOP80 and supported by minimum contents noted above.
	Other Spill	1.42 m^3/s		All periods	

Appendix A2
(Metric Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Box Canyon (1460)				None Noted	
Grand Coulee (1280)	Minimum Flow	849.50 m^3/s		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	2064.7 hm^3 0.0 hm^3	377.95 m 368.20 m	May Empty at end of CP	Retain as a power operation (for pumping)
	Step II & III only	6256.2 hm^3	392.58 m	Aug-Nov	
	Maximum Content Step I only:		0.61 m 0.91 m	Operating room Sep - Nov Operating room Dec - Feb	In place in AOP89. Retain as a power
	Draft Limit		0.40 m/day 0.46 m/day	(bank sloughage) (Constraint submitted as 0.46 m/day interpreted as 0.40 m/day mo. ave.)	
Chief Joseph (1270)	Other Spill	14.16 m^3/s		All periods	
Wells (1220)	Other Spill	33.98 m^3/s		All periods	With fish ladder
	Fish Spill			Removed	
Rocky Reach (1200)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	5.66 m^3/s		Aug 31 - Apr 15 (leakage)	
	Fish Spill			Removed	
Rock Island (1170)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Fish Spill			Removed	
Wanapum (1165)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	62.30 m^3/s		All periods	With fish ladder
	Fish Spill			Removed	
Priest Rapids (1160)	Minimum Flow			Limit removed	
	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	62.30 m^3/s		All periods	With fish ladder
	Fish Spill			Removed	

Appendix A2
(Metric Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
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Project Name (Number)	Constraint Type	Requirements			Source
Brownlee (767)	Minimum Flow	141.58 m^3/s		All periods	In place in AOP79, AOP80, AOP84
	Power Operation			Agree to use "old" power operation (first codes) provided by IPC and used in AOP since AOP97. More recent information for BRN from IPC operates the project variably (depending on inflow estimates) and for flow augmentation and water temperature control (S. Davis communication with IPC, 1992 and 1994).	2-1-91 PNCA submittal
Oxbow (765)	Other Spill	2.83 m^3/s		All periods	
Ice Harbor (502)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	20.95 m^3/s		All periods	
	Incremental Spill			None	
	Fish Spill			None	
	Minimum Flow			None	
	Other	501.1 hm^3	134.11 m	Run at all periods	
McNary (488)	Other Spill	98.40 m^3/s		All periods	
	Incremental Spill			None	
John Day (440)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	22.65 m^3/s		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
	Minimum Flow	1415.83 m^3/s 353.96 m^3/s		Mar - Nov Dec - Feb	
	Other	464.9 hm^3	80.77 m	Use JDA as a run-of-river plant.	
The Dalles (365)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	36.81 m^3/s		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
	Minimum Flow	1415.83 m^3/s 353.96 m^3/s		Mar - Nov Dec - Feb	

Appendix A2
(Metric Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:
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Project Name (Number)	Constraint Type	Requirements			Source
Bonneville (320)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	227.67 m^3/s		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
Kootenay Lake (Corra Linn (1665))	Minimum Flow	141.58 m^3/s		All periods	BCHydro agreements 1969
	Other			Operate to IJC orders.	CRTOC agreement on procedures to implement 1938 IJC order
Chelan (1210)	Minimum Flow	1.42 m^3/s		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	754.8 hm^3	334.67 m	Jul - Sep (except as needed to empty at end of critical period).	In place in AOP79, AOP80, AOP84
Couer d'Alene L (1341)	Minimum Flow	1.42 m^3/s		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	275.2 hm^3	648.61 m	May - Aug	In place in AOP79

Appendix A2
(Metric Units)
Project Operating Procedures
2001-02 Assured Operating Plan and Determination of Downstream Power Benefits

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Project Name (Number)	Constraint Type	Requirements			Source
Other Major Step I Projects					
Libby (1760) Without sturgeon	Minimum Flow	113.27 m^3/s		All periods	In place in AOP79 and AOP86
	Other Spill	5.66 m^3/s		All periods	
	Minimum Content	By contract year: Aug-Jul i.e., 1929 = Aug 1928 - Jul 1929			
		1900.8 hm^3	720.24 m	1929 Dec	2-1-93 PNCA submittal, in place in AOP99 (w/o sturgeon)
		1655.1 hm^3	717.80 m	1929 Jan	
		1476.8 hm^3	715.98 m	1929 Feb	
		5254.6 hm^3	744.63 m	1929 Jul	
		1595.2 hm^3	717.19 m	1930 Dec	
		1059.9 hm^3	711.40 m	1930 Jan	
		952.5 hm^3	710.18 m	1930 Feb	
		852.6 hm^3	708.96 m	1930 Mar	
		727.6 hm^3	707.44 m	1930 Apr 15	
		1086.8 hm^3	711.71 m	1930 Apr 30	
		1221.1 hm^3	713.23 m	1930 May	
		3289.7 hm^3	732.13 m	1930 Jun	
		4335.1 hm^3	739.14 m	1930 Jul	
		777.5 hm^3	708.05 m	1931 Dec	
		470.2 hm^3	704.09 m	1931 Jan	
		252.2 hm^3	701.04 m	1931 Feb-Apr 30	
		470.2 hm^3	704.09 m	1931 May	
		1655.1 hm^3	717.80 m	1931 Jun	
		2123.6 hm^3	722.38 m	1931 Jul	
		426.7 hm^3	703.48 m	1932 Dec	
		252.2 hm^3	701.04 m	1932 Jan	
		0.0 hm^3	697.08 m	Empty at end of CP***	
		1900.8 hm^3	720.24 m	All Dec	
		July 1930 - No more than 912.8 hm^3 lower than July 1929 July 1931 - No more than 2097.0 hm^3 lower than July 1930 March - Implement PNCA 6(c)2(c)			2-1-94 PNCA submittal, in place in AOP00 and AOP01 (w/o sturgeon)
	Maximum Summer Draft		1.52 m		
	Other			Operate to meet IJC orders for Corra Linn	CRTOC agreement on procedures to implement 1938 IJC order

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(Metric Units)
Project Operating Procedures
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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Dworshak (535)	Minimum Flow	42.47 m^3/s		All periods	2-1-96 PNCA submittal
	Maximum Flow	396.43 m^3/s		All periods	2-1-96 PNCA submittal
		707.91 m^3/s		(up to for flood control)	
	Minimum Elev	968.4 hm^3	463.30 m	SMIN Apr-Aug 31	
	Start 4 yr CP at: End 4 yr CP at:	960.5 hm^3 808.1 hm^3	463.14 m 460.16 m	(0.15 m lower), (5.94 m higher).	
	Other	Run on minimum flow or flood control observing maximum & minimum flow requirements all periods except to meet LWG outflows:			2-1-96 PNCA submittal
	LWG Target Flow	2406.91 m^3/s 1415.83 m^3/s	2831.66 m^3/s 1557.41 m^3/s	Apr 10 - Jun 20, and Jun 21 - Aug 31.	
	Other Spill	2.83 m^3/s			
Lower Granite (520)	Bypass Date			None	
	Other Spill	18.97 m^3/s		All periods	
	Incremental Spill			Removed	
	Fish Spill		16.0% 40.0% 26.7%	Apr 15 Apr 30 & May Jun	2-1-96 PNCA submittal
	Maximum Spill	566.33 m^3/s			
	Minimum Flow	325.64 m^3/s		Mar-Nov	
	Other	542.7 hm^3 601.4 hm^3	223.42 m 224.94 m	Run at (MOP) Apr 30 - Oct. Run at all other periods.	
Little Goose (518)	Bypass Date			None	
	Other Spill	17.84 m^3/s		All periods	
	Incremental Spill			Removed	
	Fish Spill		16.0% 40.0% 26.7%	Apr 15 Apr 30 & May Jun	2-1-96 PNCA submittal
	Maximum Spill	566.33 m^3/s			
	Minimum Flow	325.64 m^3/s		Mar - Nov	
	Other	636.6 hm^3 697.3 hm^3	192.94 m 194.46 m	Run at Apr 15 - Aug 31. Run at all other periods.	

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(Metric Units)
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Definition of split months:
Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Lower Monumental (504)	Bypass Date			A bypass date of 2010 was assumed.	
	Other Spill	21.24 m^3/s		All periods	
	Fish Spill		16.2% 40.5% 27.0%	Apr 15 Apr 30 & May Jun	2-1-96 PNCA submittal
	Maximum Spill	424.75 m^3/s			
	Minimum Flow	325.64 m^3/s		Mar-Nov	
	Other	439.2 hm^3 465.1 hm^3	163.68 m 164.59 m	Run at Apr 15 - Aug 31. Run at all other periods.	
Cushman (2206)	Other Spill	2.83 m^3/s			
White River (2160)	Other Spill	3.68 m^3/s		All periods	
Round Butte (390)	Other Spill	5.66 m^3/s		All periods	

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 2001-02

TABLE OF CONTENTS

Section	Page
1. Introduction	1
2. Results of Canadian Entitlement Computations	2
3. Computation of Maximum Allowable Reduction in Downstream Power Benefits	2
4. Effect on Sale of Canadian Entitlement	3
5. Canadian Entitlement Return	4
6. Summary of Canadian Entitlement Computations	4
7. Summary of Changes from Previous Year	6
(a) Loads and Non-Hydro Resources	6
(b) Operating Procedures	7
(c) Step III Critical Streamflow Period	8
(d) Downstream Power Benefits Computation	8
Table 1A - Determination of Firm Energy Hydro Loads for Step I Studies	9
Table 1B - Determination of Firm Peak Hydro Loads for Step I Studies	10
Table 2 - Determination of Thermal Displacement Market	11
Table 3 - Determination of Loads for Step II and Step III Studies	12
Table 4 - Summary of Power Regulations for Step I, II, & III Studies (English Units)	13
Table 4M - Summary of Power Regulations for Step I, II, & III Studies (Metric Units)	14
Table 5 - Computation of Canadian Entitlement (English & Metric Units)	15
Table 6 - Comparison of Recent DDPB Studies (English & Metric Units)	16
Chart 1 - Duration Curves of 30 Years Monthly Hydro Generation	18

DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB) FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2001-02

January 2000

1. Introduction

The treaty between Canada and the United States of America relating to the cooperative development of the water resources of the Columbia River Basin (Treaty) requires that downstream power benefits from the operation of Canadian Treaty storage be determined in advance by the two Entities. The purpose of this document is to describe the results of the downstream power benefit computations developed from the 2001-02 Assured Operating Plan (AOP).

The procedures followed in the benefit studies are those provided in Article VII; Annex A, paragraph 7, and Annex B of the Treaty; in paragraphs VIII, IX, and X of the Protocol; and in the following Entity agreements:

- 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," signed 29 August 1996;
- The "Columbia River Treaty Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans" (POP), dated December 1991; and
- The Entity Agreements, signed 28 July and 12 August 1988, on Principles and on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies (1988 Entity Agreements).

The Canadian Entitlement Benefits were computed from the following studies:[1]

Step I -- Operation of the total United States of America planned hydro and thermal system, with 15.5 million acre-feet (Maf) (19.12 cubic-kilometers (km^3)) of Canadian storage operated for flood control and optimum power generation in both countries.

Step II -- Operation of the Step I thermal system, the United States base hydro system, and 15.5 Maf (19.12 km^3) of Canadian storage operated for flood control and optimum power generation in both countries.

Step III -- Operation of the Step I thermal system and the United States base hydro system operated for flood control and optimum power generation in the United States.

[1] The Treaty defines the Canadian storage precisely in English units. The metric conversion is a rounded approximation.

As part of the DDPB for the operating year 2001-02, separate determinations were carried out relating to the limit of year-to-year change in benefits attributable to the operation of Canadian Treaty storage in operating plans designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States of America (Joint Optimum).

Since the Canadian Entitlement Purchase Agreement was based on the operation of Canadian Treaty storage for optimum power generation in the U.S. only (U.S. Optimum), the decrease in the downstream power benefits resulting from the operation of Canadian Treaty storage for Joint Optimum power generation, was separately determined.

2. Results of Canadian Entitlement Computations

The Canadian Entitlement to the downstream power benefits in the United States of America attributable to operation in accordance with Treaty Annex A, paragraph 7, for optimum power generation in Canada and the United States of America, which is one-half the total computed downstream power benefits, was computed to be (See Table 5 Joint Optimum):

Dependable Capacity	= 1427.1	MW
Average Annual Usable Energy	= 532.6	aMW

All downstream power benefits computations are rounded to the nearest tenth of a megawatt.

3. Computation of Maximum Allowable Reduction in Downstream Power Benefits

In accordance with the Treaty Annex A, paragraph 7 and Part III, paragraph 15c(2) of POP, the computation of the maximum allowable reduction in downstream power benefits and the resulting minimum permitted Canadian Entitlement to downstream power benefits for the 2001-02 operating year are based on the formula: Minimum Canadian Entitlement = X - (Y - Z). The quantities X, Y, and Z, expressed in terms of entitlement to downstream power benefits, are computed as follows:

X = One-half of the downstream power benefits derived from the difference between the 2000-01 Step II Joint Optimum study and the Step III study.

Y = One-half of the downstream power benefits derived from the difference between the 2000-01 Step II U.S. Optimum study and the Step III study.

Z = One-half of the downstream power benefits derived from the difference between the 2001-02 Step II U.S. Optimum study with 15 Maf (18.50 km^3) of Canadian storage and the Step III study.

The purpose of this formula is to set a lower limit on the Canadian Entitlement for the re-operation of Canadian storage. This minimum is based on the previous operating year Canadian Entitlement, plus the removal of 0.5 Maf (0.62 km^3) of

Canadian storage, and taking out the effect due to changes in loads, resources, and other operating procedures.

The quantities X and Y were computed in the 2000-01 DDPB Table 5. The quantity Z is computed in Table 5 of this report. The computation of the Minimum Canadian Entitlement is as follows:

Dependable Capacity	= 1447.3 - (1447.3 - 1403.0) =1403.0 MW
Average Annual Usable Energy	= 508.4 - (507.7 - 520.8) = 521.5 aMW

The computed Canadian Entitlement exceeds these amounts.

4. Effect on Sale of Canadian Entitlement

The Canadian Entitlement to downstream power benefits was purchased by the Columbia Storage Power Exchange (CSPE) pursuant to the Canadian Entitlement Purchase Agreement (CEPA) dated 13 August 1964, for a period of thirty years following the completion of each Canadian storage project. The purchase of the Canadian Entitlement by the United States under CEPA expires 31 March 1998 for Duncan, 31 March 1999 for Arrow, and 31 March 2003 for Mica.

The studies developed for this sale included the assumption of operation of Treaty storage for optimum power generation only in the United States of America (U.S. Optimum). The Canadian Entitlement determined from the 2001-02 AOP for this condition was:

Dependable Capacity	= 1427.1 MW
Average Annual Usable Energy	= 532.2 aMW

Because the 2001-02 AOP was designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States of America, Section 7 of the Agreement requires that "any reduction in the Canadian Entitlement resulting from action taken pursuant to paragraph 7 of Annex A of the Treaty shall be determined in accordance with Subsection (3) of Section 6 of this Agreement." A comparison of the Canadian Entitlement for optimum power in Canada and the United States with the Canadian Entitlement to downstream power benefits shown above indicates an <u>increase</u> in the energy Entitlement of 0.4 aMW and <u>no change</u> in the capacity.

Since the sale of the downstream power benefits attributable to Duncan and Arrow expires 31 March 1998 and 31 March 1999 respectively, the United States Entity is entitled to that portion of the decrease in Canadian Entitlement attributed to Mica. Because there was no decrease in Canadian Entitlement, the United States Entity is not entitled to any compensation attributed to the re-operation of Mica. Accordingly, the Entities are agreed that the United States Entity is not entitled to receive any energy or dependable capacity during the period 1 April 2001 through 31 March 2002, from B.C. Hydro & Power Authority, in accordance with Sections 7 and 10 of the CEPA.

5. Canadian Entitlement Return

As noted above, the sale of the Canadian Entitlement attributable to Duncan storage and Arrow storage terminates on 31 March 1998 and 31 March 1999 respectively, under Section 2.(1)(a) of the CEPA. Under Section 2.(3) of this agreement, the percentage of the downstream power benefits allocable to each Canadian storage project is the percentage of the total of the Canadian storages provided by that storage as set out in Article II of the Treaty.

The storage volume in Duncan is 1.4 Maf (1.73 km^3), in Arrow is 7.1 Maf (8.76 km^3), and the whole of Canadian storage is 15.5 Maf (19.12 km^3). Therefore, the obligation of the United States to deliver Canadian Entitlement to Canada for operating year 2001-02 beginning 1 August 2001 and ending 31 July 2002, based on the Joint Optimum power studies, for benefits attributable to Duncan and Arrow is computed below.

a) Energy Entitlement Returned
Average Annual Usable Energy =
532.6 aMW * (8.5 Maf/15.5 Maf) = 292.1 aMW
532.6 aMW * (10.48 km^3/19.12 km^3) = 292.1 aMW

b) Capacity Entitlement Returned
Dependable Capacity =
1427.1 MW * (8.5 Maf/15.5 Maf) = 782.6 MW
1427.1 MW * (10.48 km^3/19.12 km^3) = 782.6 MW

6. Summary of Canadian Entitlement Computations

The following tables and chart summarize the study results.

Table 1. Determination of Firm Hydro Loads for Step I Studies:

This table shows the loads and resources used in the Step I studies and the computation of the coordinated hydro firm load for the Step I hydroregulation study. This table follows the definition of Step I loads and resources as defined by Treaty Annex B, paragraph 7, and clarified by the 1988 Entity Agreements. Table 1A shows the Step I energy loads and resources while Table 1B shows the Step I peak loads and resources.

Table 2. Determination of Thermal Displacement Market:

This table shows the computation of the thermal displacement market for the downstream power benefit determination of average annual usable energy. The thermal displacement market was limited to the existing and scheduled thermal energy capability including thermal imports after allowance for energy reserves, minimum thermal generation, and reductions for the thermal resources used outside the Pacific Northwest Area (PNWA).

Table 3. Determination of Loads for 2001-02 Step II and Step III Studies:

This table shows the computation of the Step II and III loads. The monthly loads for Step II and III studies have the same ratio between each month and the annual average as does the PNWA load. The PNWA firm loads on this table were based on the BPA 1995 Whitebook load forecast. The Grand Coulee pumping load is also included in this estimate. The method for computing the firm load for the Step II and III studies is described in the 1988 Entity Agreements and in POP.

Table 4. Summary of Power Regulations from 2001-02 01 Assured Operating Plan:

This table summarizes the results of the Step I, II, and III power regulation studies for each project and the total system. The determination of the Step I, II, and III loads and thermal installations is shown in Tables 1 and 3.

Table 5. Computation of Canadian Entitlement For 2001-02 01 Assured Operating Plan:

A. Optimum Generation in Canada and the U.S.
B. Optimum Generation in the U.S. Only
C. Optimum Generation in the U.S. and a 0.5 Maf (0.62 km^3) Reduction in Total Canadian Treaty Storage

The essential elements used in the computation of the Canadian Entitlement to downstream power benefits, the minimum permitted downstream power benefits, and the reduction in downstream power benefits attributable to the operation of Canadian Treaty storage for optimum power generation in the United States of America only are shown on this table.

Table 6. Comparison of Recent DDPB Studies

Chart 1. Duration Curves of 30 Years Monthly Hydro Generation:

This chart shows duration curves of the hydro generation from the Step II and III studies, which graphically illustrates the change in average annual usable energy. Usable Energy is firm energy plus usable secondary energy. Secondary energy is the energy capability each month that exceeds the firm hydro loads shown in Table 3. The usable secondary energy in average megawatts for the Step II and III studies is computed in accordance with Annex B, paragraphs 3(b) and 3(c), as the portion of secondary energy which can displace thermal resources that were used to meet PNWA loads plus the other usable secondary generation. The Entities have agreed that "the other usable secondary" is computed on the basis of 40 percent of the secondary energy remaining after thermal displacement.

7. Summary of Changes from Previous Year

Data from the five most recent DDPB's are summarized in Table 6. Firm energy shifting was not included in any of these operating plan studies. An explanation of the more important changes compared to last year's studies follows.

(a) Loads and Non-Hydro Resources

Loads for the 2001-02 AOP were based on the 1995 Whitebook medium case forecast developed by BPA in November 1995. Compared to the previous AOP, the PNWA firm energy load increased by 534 aMW. The total exports, not including firm surplus energy, increased by 89 aMW. The increase in exports is mainly due to the increased Canadian Entitlement Return. It was assumed that all of the Entitlement Return was exported to B.C. with one-half of the amount imported back to meet load in the PNWA. The surplus firm energy decreased by 426 aMW and was shaped to meet load only in May and June.

The estimated increase in the Step I load due to the return of the Canadian Entitlement Return exported to Canada assumed in the studies, and the computed Canadian Entitlement Return attributed to Duncan and Arrow for the period 1 August 2001 through 31 July 2002, are shown below for the Joint Optimum studies. The Entitlement Return which was assumed to be imported to meet load in the PNWA is also shown in the table.

	Energy Entitlement Returned (aMW)		**Capacity Returned (MW)**	
	Estimated	Computed	Estimated	Computed
Export to BC	276.2	292.1	783.0	782.6
Import to PNW	138.1	--	391.5	--

Iterative studies to correct the load estimate were not performed because updating the Canadian Entitlement Return estimates would not significantly affect the results of the studies.

The total annual energy capability of the thermal installations decreased by 8 aMW. Major thermal resource changes included:

- Combustion Turbine resources decreased by 139 aMW due to removal of BPA's Tenaska and Idaho's Wood River projects, and removal of maintenance at PGE's Beaver and Unnamed projects;
- Cogeneration decreased 42 aMW due to the removal of the Klickitat SDS Lumber project and a change in the maintenance schedule for PGE's Coyote Springs;

- Boardman Coal increased by 107 aMW due to a change in maintenance schedule and an upgrade;

- Thermal Non-Utility Generation (NUG) decreased by 34 aMW mostly due to the termination of Springfield's and Clallam County's NUG's, and a decrease in WWP's;

- Thermal Imports increased by 107 aMW due to changes in the Southern California Edison (SCE) to BPA imports, and a new import from Imperial to BPA. Montana Thermal Import decreased and showed different monthly shaping from the previous year's data; and

- Plant Sales increased by 8 aMW due to a change in the maintenance schedule for Boardman, thus PGE's share that was sold to San Diego also increased. This amount is subtracted from the thermal installations.

(b) Operating Procedures

Plant data for Waneta, 7-Mile, Arrow, Rock Island, and Ice Harbor were revised. Generation increased due to an upgrade at Waneta and an expansion at 7-Mile. The addition of generators at Arrow is assumed not to be completed by 2002. The generation vs. discharge (MW/cfs) table was updated for Rock Island. The end storage vs. elevation and head vs. H/K (kW/cfs) tables were updated for Ice Harbor.

The established operating procedures for Base system projects were agreed to by an Entity Agreement signed on 29 August 1996. These requirements are essentially the nonpower requirements included in the 1979-80 and prior AOP/DDPB studies. Major changes from the previous studies included (See Appendixes A1 and A2):

- Hungry Horse minimum flow requirement increased to 400 cfs (11.33 m^3/s) from 145 cfs (4.11 m^3/s) in all periods. The requirement to meet Columbia Falls minimum flow of 3500 cfs (99.11 m^3/s), and the maximum of 4500 cfs (127.42 m^3/s) was eliminated;

- Kerr minimum flow decreased to 1500 cfs (42.48 m^3/s) in all periods. In the previous year's AOP, minimum flow ranged from 3200 cfs (90.61 m^3/s) in most periods to a high of 7742 cfs (219.23 m^3/s) in May;

- Only the 1240 feet (ft) (377.95 m) pumping requirement in May remained for Grand Coulee. The 1285 ft (391.67 m) minimum storage for recreation and 1220 ft (371.86 m) minimum for Ferry operations were eliminated;

- All fish spill was eliminated for base system projects (not including fish ladders, lockage, sluiceway);

- John Day was operated to pre-2001 operation with minimum operating pool of 265 ft (80.77 m).

(c) Step III Critical Streamflow Period

The Step III study critical stream flow period was a 6-1/2 month critical period, 1 October 1936 through 15 April 1937. There was no unshapeable surplus firm energy in October as there was in the 2000-01 study. The critical period ended 1/2 period sooner because of the change in the thermal maintenance schedule.

(d) Downstream Power Benefits Computation

The Capacity Entitlement decreased from 1447.3 MW in the 2000-01 DDPB to 1427.1 MW in the 2001-02 DDPB for a loss of 20.2 MW. This was mainly due to an increase in the average critical period load factor.

The Canadian Energy Entitlement increased from 508.4 aMW in the 2000-01 DDPB to 532.6 aMW in the 2001-02 DDPB, an increase of 24.2 aMW. The following parameters were identified as having the most significant impacts.

Thermal Displacement Market

The Thermal Displacement Market increased by 314 aMW in the AOP02 compared to the AOP01. This is mainly due to a decrease in average Annual System Sales of 426 aMW. The increased Thermal Displacement Market caused the Energy Entitlement to decrease by approximately 9 aMW.

Grand Coulee ORC

Grand Coulee operated as an annual project because the March Assured Rule Curve (ARC) was empty, and other projects had to draft below their ARC's to meet firm load. As an annual project Coulee does not have a Variable Refill Curve, and the resulting ORC's were generally higher January through June than the ORC's in the previous study. This caused a significant increase in the Energy Entitlement.

TABLE 1A
2001-02 ASSURED OPERATING PLAN
DETERMINATION OF FIRM ENERGY HYDRO LOADS FOR STEP I STUDIES (aMW) 1/

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July	Annual Average	CP Ave 2/ (42.5 Mon)
1. **Pacific Northwest Area (PNWA) Load**	20337	20259	19827	20487	22412	23992	24603	23533	22215	21019	21116	20496	20351	20512	21641.7	21742.4
a) Annual Load Shape in Percent	93.97	93.61	91.61	94.66	103.56	110.86	113.68	108.74	102.65	97.12	97.57	94.70	94.04	94.78	100.0	100.5
2. **Flows-Out of firm power from PNWA**																
a) Firm Exports 3/	1349	1349	1367	1071	1030	1031	1004	980	1018	1020	1056	1132	1448	1399	1156.3	1148.0
b) Exclude Plant Sales	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-101.9	-101.9
c) Firm Surplus	0	0	0	0	0	0	0	0	0	0	0	1877	1877	0	313.7	265.7
d) ...Total	1247	1247	1265	969	929	929	902	878	916	918	954	2907	3223	1297	1368.1	1311.8
3. **Load served by Flows-In of firm power except Step I thermal installations**																
a) Non-thermal firm imports 4/	-158	-158	-153	-159	-174	-185	-198	-207	-199	-168	-168	-166	-176	-164	-175.4	-175.7
b) Seasonal Exchange Imports	0	0	0	0	-280	-286	-286	-286	-30	-6	-6	0	0	0	-96.6	-108.4
d) ...Total	-158	-158	-153	-159	-454	-471	-484	-493	-229	-174	-174	-166	-176	-164	-272.0	-284.2
4. **Load served by non-Step I resources located within the PNWA**																
a) Hydro Independents (1929 water)	-1260	-1201	-1068	-1133	-1153	-1046	-1087	-814	-957	-1268	-1327	-1794	-1603	-1281	-1207.6	-1063.2
b) Non-Step I Coordinated Hydro (1929 water)	-536	-464	-561	-962	-960	-1076	-1210	-659	-708	-872	-846	-659	-1038	-633	-819.7	-851.3
c) Non-Thermal PURPA/NUGS	-164	-164	-152	-145	-143	-140	-116	-118	-123	-139	-138	-148	-150	-145	-140.3	-139.9
e) Miscellaneous Resources	-46	-46	-51	-59	-71	-80	-81	-76	-68	-62	-62	-57	-54	-47	-62.4	-63.2
f) ...Total (1929 water)	-2006	-1875	-1831	-2299	-2327	-2342	-2494	-1667	-1856	-2341	-2374	-2657	-2844	-2105	-2229.9	-2117.5
5. **Total Step I System Firm Loads (1929 water)**	19421	19473	19108	18999	20559	22107	22527	22250	21046	19423	19522	20580	20553	19539	20507.9	20652.5
6. **Step I Thermal Installations**																
a) Large Thermal (includes plant sales)	4670	4670	4670	4670	4670	4670	4670	4670	4483	4136	3419	2578	4229	4670	4366.8	4413.3
b) Small Thermal	32	32	32	32	33	33	33	33	32	32	32	32	32	32	32.4	32.4
c) Combustion Turbines	1924	1840	1821	2061	2019	2061	2061	2061	2061	1604	1612	1888	1944	2053	1960.7	1966.8
d) Cogeneration (includes plant sales)	1538	1538	1527	1528	1529	1531	1532	1531	1531	1541	1450	935	1538	1538	1478.8	1486.8
e) Thermal PURPA/NUGS	246	246	227	217	214	211	174	178	185	208	208	221	224	218	210.4	209.9
f) Thermal classified as Renewables	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52.1	52.1
g) Thermal Firm Imports	1206	1249	1016	1123	1763	2002	2222	2269	1879	1648	1134	1006	1098	1268	1518.2	1544.7
h) Exclude Seas Exch Imports (see 3b) 5/	0	0	0	0	-280	-286	-286	-286	-30	-6	-6	0	0	0	-96.6	-108.4
i) Exclude Plant Sales (see 2b) 6/	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-101.9	-101.9
j) ...Total	9567	9526	9244	9581	9898	10172	10356	10406	10092	9115	7800	6612	9017	9730	9420.9	9495.5
7. **Total Step I Hydro Load (1929 water) 7/**	9854	9948	9864	9417	10661	11936	12171	11844	10953	10308	11722	13968	11536	9809	11087.0	11157.0
a) Hydro Maintenance as a load	32	27	9	9	4	0	0	0	5	7	8	20	16	51	12.7	11.6
b) Coordinated Hydro Model Load (1929 water) 8/	10422	10439	10434	10388	11626	13012	13382	12502	11667	11187	12575	14647	12590	10493	11919.3	12019.8

1/ Step I Loads and Resources for the U.S. Optimum Study (02-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements. Total regional firm load plus pumping.

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

3/ Includes 276 aMW uniform export of Canadian Entitlement. All is returned to Canada and one-half is imported to the region.

4/ Includes 138 aMW uniform import of Canadian Entitlement. The remaining is Skagit River Treaty.

5/ The Seasonal Exchange Imports are included in Thermal Firm Imports, line 6(g).

6/ Plant sales include Longview Fibre (Cogeneration, line 6(d)) and 15 percent of Boardman (Large Thermal, line 6(a)).

7/ Regulated hydro load for U.S. projects located upstream of Bonneville Dam, line 5 minus line 6(j).

8/ The Coordinated Hydro Model Load is the Step I Hydro Load plus Hydro Maintenance plus Non-Step I Coordinated Hydro.

TABLE 1B
2001-02 ASSURED OPERATING PLAN
DETERMINATION OF FIRM PEAK HYDRO LOADS FOR STEP I STUDIES (MW) 1/

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July
1. **Pacific Northwest Area (PNWA) Load**	25099	25054	24908	27406	29519	32007	32717	32128	29711	28109	28191	26564	25620	25168
a) Load Shape in Percent	80.86	80.86	79.60	74.75	75.92	74.96	75.20	73.25	74.77	74.73	74.73	77.16	79.43	81.50
2. **Flows-Out of firm power from PNWA**														
a) Firm Exports 2/	3295	3295	3297	2690	1735	1723	1723	1799	1774	1766	1816	2090	3322	3337
b) Exclude Plant Sales	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-45	-116	-116
c) Firm Surplus	0	0	0	0	0	0	0	0	0	0	0	2433	2363	0
d) ...Total	3179	3179	3181	2574	1619	1607	1607	1683	1658	1650	1700	4478	5569	3221
3. **Load served by Flows-In of firm power except Step I thermal installations**														
a) Non-thermal firm imports 3/	-538	-538	-538	-538	-526	-540	-562	-586	-616	-538	-538	-538	-538	-538
b) Seasonal Exchange Imports	0	0	0	0	-601	-601	-601	-601	-46	-12	-12	0	0	0
c) ...Total	-538	-538	-538	-538	-1127	-1141	-1163	-1187	-662	-550	-550	-538	-538	-538
4. **Loads served by non-Step I resources located withinin the PNWA**														
a) Hydro Independents (1937 water)	-1926	-1911	-1839	-1792	-1725	-1695	-1635	-1761	-1846	-1970	-1994	-2171	-2197	-2032
b) Non-Step I Coordinated Hydro (1937 water)	-2438	-2457	-2508	-2477	-2408	-2362	-2217	-1999	-2011	-1990	-2096	-1933	-2331	-2511
c) Non-Thermal PURPA/NUGS	-169	-169	-158	-151	-148	-145	-121	-123	-130	-144	-144	-153	-154	-150
d) Miscellaneous Resources	-33	-33	-36	-37	-339	-341	-340	-339	-340	-40	-40	-39	-38	-34
e) ...Total (1937 water)	-4566	-4569	-4541	-4456	-4620	-4543	-4314	-4222	-4327	-4144	-4274	-4295	-4719	-4727
5. **Total Step I System Firm Loads (1937 water)**	23174	23125	23010	24986	25392	27931	28848	28403	26381	25065	25067	26209	25932	23124
6. **Step I Thermal Installations**														
a) Large Thermal (includes plant sales)	5349	5349	5349	5349	5349	5349	5349	5349	5084	4872	3876	3091	4333	5349
b) Small Thermal	38	38	38	38	41	41	41	41	38	38	38	38	38	38
c) Combustion Turbines	2213	2035	2151	2452	2461	2466	2469	2464	2458	1597	1558	2047	2224	2220
d) Cogeneration (includes plant sales)	1604	1604	1593	1594	1595	1597	1598	1597	1597	1607	1607	1059	1444	1604
e) Thermal PURPA/NUGS	253	253	237	227	222	218	182	185	195	216	216	229	230	225
f) Thermals classified as Renewables	52	52	52	52	52	52	53	53	53	53	53	53	53	53
g) Thermal Firm Imports	1479	1479	1135	1366	1948	2235	2459	2426	1908	1545	1270	1624	1629	1494
h) Exclude Seas Exch Imports (see 3b) 4/	0	0	0	0	-601	-601	-601	-601	-46	-12	-12	0	0	0
i) Exclude Plant Sales (see 2b) 5/	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-45	-116	-116
j) ...Total	10872	10694	10438	10961	10950	11240	11433	11397	11171	9800	8490	8095	9835	10866
7. **Total Step I Hydro Load (1937 water) 6/**	12302	12432	12572	14025	14442	16691	17415	17006	15210	15265	16577	18114	16098	12258
a) Hydro Maintenance as a load	4629	4066	3787	3208	2935	2037	1561	2295	2646	2751	2483	2360	2204	3725
b) Coordinated Hydro Model Load (1937 water) 7/	19369	18954	18867	19710	19784	21090	21194	21301	19866	20006	21156	22406	20632	18494

1/ Step I Loads and Resources for the U.S. Optimum study (02-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements. Total regional firm load plus pumping.
2/ Includes 783 MW uniform export of Canadian Entitlement. All is returned to Canada and one-half is imported to the region.
3/ Includes 391.5 MW uniform import of Canadian Entitlement. The remaining is Skagit River Treaty.
4/ The Seasonal Exchange Imports are included in Thermal Firm Imports, line 6(g).
5/ Plant sales include Longview Fibre (Cogeneration, line 6(d)) and 15 percent of Boardman (Large Thermal, line 6(a)).
6/ Regulated hydro load for U.S. projects located upstream of Bonneville Dam, line 5 minus line 6(j).
7/ The Coordinated Hydro Model Load is the Step I Hydro Load plus Hydro Maintenance plus Non-Step I Coordinated Hydro.

TABLE 2
2001-02 ASSURED OPERATING PLAN
DETERMINATION OF THERMAL DISPLACEMENT MARKET
(Energy in aMW)

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	June	July	Annual Average	CP Ave (42.5 Mon)
1. STEP I THERMAL INSTALLATIONS	9567	9526	9244	9581	9618	9886	10070	10120	10062	9109	7794	6612	9017	9730	9324.3	9387.1
2. MINIMUM THERMAL GENERATION																
a) Large Thermal Min. Generation	147	147	456	456	456	456	456	456	456	147	147	147	147	147	326.5	342.5
b) Cogen & Small Thermal Min. Gen	453	453	455	458	460	461	461	460	460	459	459	223	455	453	437.8	441.0
c) NUGS Thermal Min. Generation	82	82	76	72	71	70	58	59	62	69	69	74	75	73	70.1	70.0
d) ...Total Minimum Generation	682	682	987	986	987	987	975	975	978	675	675	444	677	673	834.4	853.4
3. DISPLACEABLE THERMAL RESOURCES	8885	8844	8257	8595	8630	8899	9095	9145	9085	8434	7119	6168	8340	9058	8489.9	8533.7
4. SYSTEM SALES																
a) Total Exports	1349	1349	1367	1071	1030	1031	1004	980	1018	1020	1056	1132	1448	1399	1156.3	1148.0
b) Exclude Can Entitlement (out of the PNWA)	-276	-276	-276	-276	-276	-276	-276	-276	-276	-276	-276	-276	-276	-276	-276.2	-276.2
c) Exclude Plant Sales Exports	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-101.9	-101.9
d) Exclude Seasonal Exchange Exports	-272	-272	-283	-15	0	0	0	0	0	0	0	0	-283	-283	-94.8	-90.5
e) Firm Surplus Sales	0	0	0	0	0	0	0	0	0	0	0	1877	1877	0	313.7	265.7
f) ...Total System Sales	700	700	706	678	652	653	626	602	639	642	678	2631	2664	738	997.1	945.0
g) Uniform Average Annual System Sales	997	997	997	997	997	997	997	997	997	997	997	997	997	997	997.1	997.1
5. THERMAL DISPLACEMENT MARKET	7888	7847	7260	7598	7633	7901	8098	8148	8088	7436	6122	5171	7343	8060	7492.8	7536.5

Notes:

Line 1 The Total Step I Thermal Installations listed here are lower by the amount shown on Table 1A, line 6(j) due to the omission of the Seasonal Exchange imports.
Line 2a Large Thermal minimum generation includes Centralia and Jim Bridger.
Line 2b Cogen & Small Thermal Minimum Generation Includes Spokane Muni Solid Waste, Tacoma Steam Plant , Vale, EWEB Weyerhauser cogen, and PP&L cogen plants.
Line 2c 60% of the total NUGS is thermal. Non-displaceable NUGS generation is 1/3 of the thermal NUGS.
Line 2d Total Minimum Thermal Generation, the sum of lines 2(a) through line 2(c).
Line 3 Step I Thermal Installations that are displaceable, line 1 minus line 2(d).
Line 4a Total Exports from Table 1A, line 2(a).
Line 4c Plant sales include Longview Fibre and approximately 15 percent of Boardman.
Line 4d Seasonal exchanges with extraregional utilities.
Line 4f System Sales are total exports excluding plant sales, seasonal exchanges, and the Canadian Entitlement. The sum of lines 4(a) through line 4(e).
Line 4g Average Annual System Sales shaped uniformly per 1988 Entity Agreement assumption that shaping is supported by hydro system.
Line 5 PNWA Thermal Displacement Market is the Total Displaceable Thermal Resources used to meet PNWA firm loads, line 3 minus line 4(g).

TABLE 3
2001-02 ASSURED OPERATING PLAN
DETERMINATION OF LOADS FOR STEP II AND STEP III STUDIES

PACIFIC NORTHWEST AREA (PNWA) LOAD						STEP II STUDY		STEP III STUDY		
Period	PNWA Energy Load 1/ (aMW)	Annual Energy Load Shape (Percent)	Peak Load (MW)	Load Factor (Percent)	Energy Capability of Thermal Installations 2/ (aMW)	Total Load 3/ (aMW)	Hydro Load 4/ (aMW)	Total Load 3/ (aMW)	Hydro Load 4/ (aMW)	Period
August 1-15	20337	93.97	25099	80.86	9567	17187.3	7620.6	14939.2	5372.5	August 1-15
August 16-31	20259	93.61	25054	80.86	9526	17121.4	7595.6	14881.9	5356.2	August 16-31
September	19827	91.61	24908	79.60	9244	16756.3	7512.4	14564.6	5320.7	September
October	20487	94.66	27406	74.75	9581	17313.9	7732.5	15049.2	5467.9	October
November	22412	103.56	29519	75.92	9618	18940.9	9323.3	16463.4	6845.8	November
December	23992	110.86	32007	74.96	9886	20276.6	10390.8	17624.4	7738.6	December
January	24603	113.68	32717	75.20	10070	20793.0	10723.0	18073.3	8003.3	January
February	23533	108.74	32128	73.25	10120	19888.3	9767.9	17286.9	7166.5	February
March	22215	102.65	29711	74.77	10062	18774.5	8712.2	16318.8	6256.5	March
April 1-15	21019	97.12	28109	74.73	9109	17763.9	8655.0	15440.4	6331.4	April 1-15
April 16-30	21116	97.57	28191	74.73	7794	17845.7	10051.3	15511.4	7717.1	April 16-30
May	20496	94.70	26564	77.16	6612	17321.7	10709.7	15056.0	8444.0	May
June	20351	94.04	25620	79.43	9017	17199.6	8182.6	14949.8	5932.9	June
July	20512	94.78	25168	81.50	9730	17335.2	7605.0	15067.8	5337.6	July
Annual Average 7/	21641.7	100.00		76.87	9324.3	18290.2	8965.9	15897.9	6573.5	Annual Average
SI CP Average (42.5)	21742.4			76.74	9387.1	18502.7	9055.6	16693.3	6865.3	CP avg (6.5 mo)
SII CP Average (20)	21893.1				9447.1					
SIII CP Average (6.5)	22724.5				9828.0					
						Input 5/ →	**9055.6**	Input 6/ →	**6865.3**	
August 1-31	20296.4	93.8	25099.2	80.86	9545.6	17153.3	7607.7	14909.6	5364.0	August 1-31
April 1-30	21067.4	97.3	28190.9	74.73	8451.6	17804.8	9353.2	15475.9	7024.3	April 1-30

1/ The PNWA load does not include the exports, but does include pumping. The computation of the load shape for Step II/III studies used these loads.
2/ The thermal installations include all thermal used to meet the Step I system load. (Table 2, line 1).
3/ The total firm load for the Step II/III studies is computed to have the same shape as the load of the PNWA.
4/ The hydro load is equal to the total load minus the Step I study thermal installations.
5/ Input is the assumed critical period (CP) average generation for the Step II hydro studies and is used to calculate the residual hydro loads.
6/ Input is the assumed Step III 6.5-month CP average generation.
7/ The Annual Average is for 2001-02 operating year, not a leap year.

TABLE 4
(English Units)
SUMMARY OF POWER REGULATIONS
FROM 2001-02 ASSURED OPERATING PLAN

	BASIC	DATA		STEP I			STEP II				STEP III		
PROJECTS	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE ksf	JANUARY 1937 PEAKING CAP MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE ksf	JANUARY 1945 PEAKING CAP MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE ksf	JANUARY 1937 PEAKING CAP MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW
HYDRO RESOURCES													
CANADIAN													
Mica			7000			7000							
Arrow			7100			7100							
Duncan			1400			1400							
Subtotal			15500			15500							
BASE SYSTEM													
Hungry Horse	4	428	3072	323	103	3008	188	117	104	3008	304	221	102
Kerr	3	160	1219	156	120	1219	153	112	123	1219	153	126	119
Thompson Falls	6	85	0	85	54	0	85	53	58	0	85	61	58
Noxon Rapids	5	554	231	549	152	0	554	134	201	0	554	162	201
Cabinet Gorge	4	239	0	239	100	0	239	90	117	0	239	103	118
Albeni Falls	3	50	1155	22	23	1155	20	23	21	1155	12	16	21
Box Canyon	4	74	0	71	45	0	70	45	48	0	69	52	46
Grand Coulee	24+3SS	6684	5185	6369	1968	5072	6369	1763	2353	5072	5732	1196	2261
Chief Joseph	27	2614	0	2614	1117	0	2614	1017	1363	0	2614	717	1287
Wells	10	840	0	840	420	0	840	390	488	0	840	281	444
Chelan	2	54	677	51	39	676	51	38	43	676	51	44	43
Rocky Reach	11	1267	0	1267	575	0	1267	533	692	0	1267	376	646
Rock Island	18	513	0	513	256	0	513	240	301	0	513	171	279
Wanapum	10	986	0	986	518	0	986	482	603	0	986	331	540
Priest Rapids	10	912	0	912	510	0	912	477	574	0	912	338	511
Brownlee	5	675	975	675	240	974	675	313	316	974	675	269	315
Oxbow	4	220	0	220	99	0	220	124	128	0	220	114	128
Ice Harbor	6	693	0	693	212	0	693	232	303	0	693	161	303
McNary	14	1127	0	1127	653	0	1127	638	802	0	1127	469	749
John Day	16	2484	535	2484	944	0	2484	922	1254	0	2484	669	1218
The Dalles	22+2F	2074	0	2074	748	0	2074	732	993	0	2074	553	973
Bonneville	18+2F	1147	0	1147	595	0	1147	581	731	0	1147	436	694
Kootenay Lake	0	0	673	0	0	673	0	0	0	673	0	0	0
Coeur d'Alene Lake	0	0	223	0	0	223	0	0	0	223	0	0	0
Total Base and Canadian System Hydro 1/		23880	29445	23417	9491	28500	23280	9056	11613	13000	22750	6865	11058
ADDITIONAL STEP I PROJECTS													
Libby	5	600	4980	542	195								
Boundary	6	1055	0	855	368								
Spokane River Plants	24	173	104	166	99								
Hells Canyon	3	450	0	410	192	NOT APPLICABLE TO STEP II & III							
Dworshak	3	450	2015	438	128								
Lower Granite	6	932	0	930	188								
Little Goose	6	932	0	928	186								
Lower Monumental	6	932	0	922	195								
Pelton, Rereg., & RB	7	423	274	418	127								
Total added Step I		5947	7373	5610	1678								
THERMAL INSTALLATION 2/				11433	9496		11433	9447			11433	9828	
RESERVES, HYDRO MAINTENANCE 3/				-4179	-12		-2212	0			-1923	0	
TOTAL RESOURCES				36282	20653		32501	18503			32260	16693	
STEP I, II, & III LOADS 4/				28848	20653		27650	18503			24034	16693	
SURPLUS				7434	0		4851	0			8226	0	
CRITICAL PERIOD	Starts			August 16, 1928			September 1, 1943				October 1, 1936		
	Ends			February 29, 1932			April 30, 1945				April 15, 1937		
	Length (Months)			42.5 Months			20 Months				6.5 Months		
	Study Identification			02-41			02-42				02-13		

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

2/ From Tables 1 and 3.

3/ Peak reserves for Step I, II, III are 8 percent of January peak load from Table 3. Energy reserve deductions only include the hydro maintenance for Step I study (reserves have been included in thermal plant energy capability) from Table 1A, line 7(a).

4/ Step I energy load from Table 1A, line 5 and January peak load fromTable 1B, line 5. Step II & III energy load from Table 3. Step II & III peak load is equal to the step II or step III annual average load multiplied by the ratio of the PNWA January peak load to the PNW annual average load.

TABLE 4M
(Metric Units)
SUMMARY OF POWER REGULATIONS FROM 2001-02 ASSURED OPERATING PLAN

PROJECTS	BASIC DATA: NUMBER OF UNITS	BASIC DATA: NOMINAL INSTALLED PEAKING CAPACITY MW	STEP I: USABLE STORAGE hm³	STEP I: JANUARY 1937 PEAKING CAP. MW	STEP I: CRITICAL PERIOD AVERAGE GEN. MW	STEP II: USABLE STORAGE hm³	STEP II: JANUARY 1945 PEAKING CAP. MW	STEP II: CRITICAL PERIOD AVERAGE GEN. MW	STEP II: 30 YEAR AVERAGE ANNUAL GEN. MW	STEP III 4/: USABLE STORAGE hm³	STEP III 4/: JANUARY 1937 PEAKING CAP. MW	STEP III 4/: CRITICAL PERIOD AVERAGE GEN. MW	STEP III 4/: 30 YEAR AVERAGE ANNUAL GEN. MW
HYDRO RESOURCES													
CANADIAN													
Mica			8635			8635							
Arrow			8758			8758							
Duncan			1727			1727							
Subtotal			19119			19119							
BASE SYSTEM													
Hungry	4	428	3789	323	103	3710	188	117	104	3710	304	221	102
Kerr	3	160	1504	156	120	1504	153	112	123	1504	153	126	119
Thomps	6	85	0	85	54	0	85	53	58	0	85	61	58
Noxon I	5	554	285	549	152	0	554	134	201	0	554	162	201
Cabinet	4	239	0	239	100	0	239	90	117	0	239	103	118
Albeni F	3	50	1425	22	23	1425	20	23	21	1425	12	16	21
Box Ca	4	74	0	71	45	0	70	45	48	0	69	52	46
Grand (	24+3SS	6684	6396	6369	1968	6256	6369	1763	2353	6256	5732	1196	2261
Chief Jo	27	2614	0	2614	1117	0	2614	1017	1363	0	2614	717	1287
Wells	10	840	0	840	420	0	840	390	488	0	840	281	444
Chelan	2	54	835	51	39	834	51	38	43	834	51	44	43
Rocky F	11	1267	0	1267	575	0	1267	533	692	0	1267	376	646
Rock Isl	18	513	0	513	256	0	513	240	301	0	513	171	279
Wanapu	10	986	0	986	518	0	986	482	603	0	986	331	540
Priest R	10	912	0	912	510	0	912	477	574	0	912	338	511
Brownle	5	675	1203	675	240	1201	675	313	316	1201	675	269	315
Oxbow	4	220	0	220	99	0	220	124	128	0	220	114	128
Ice Harl	6	693	0	693	212	0	693	232	303	0	693	161	303
McNary	14	1127	0	1127	653	0	1127	638	802	0	1127	469	749
John Da	16	2484	660	2484	944	0	2484	922	1254	0	2484	669	1218
The Dal	22+2F	2074	0	2074	748	0	2074	732	993	0	2074	553	973
Bonnev	18+2F	1147	0	1147	595	0	1147	581	731	0	1147	436	694
Kooten	0	0	830	0	0	830	0	0	0	830	0	0	0
Coeur d	0	0	275	0	0	275	0	0	0	275	0	0	0
Total Base and Ca		23880	36320	23417	9491	35155	23280	9056	11613	16036	22750	6865	11058
ADDITIONAL STEP I PROJECTS													
Libby	5	600	6143	542	195								
Bounda	6	1055	0	855	368								
Spokan	24	173	128	166	99								
Hells Ca	3	450	0	410	192			NOT APPLICABLE TO STEP II & III					
Dworsh	3	450	2486	438	128								
Lower (	6	932	0	930	188								
Little Go	6	932	0	928	186								
Lower M	6	932	0	922	195								
Pelton,	7	423	338	418	127								
Subtotal		5947	9095	5610	1678								
THERMAL INSTALLATION 2/				11433	9496		11433	9447			11433	9828	
RESERVES, HYDRO MAINTENANCE 3/				-4179	-12		-2212	0			-1923	0	
TOTAL RESOURCES				36282	20653		32501	18503			32260	16693	
STEP I, II, & III LOADS 4/				28848	20653		27650	18503			24034	16693	
SURPLUS				7434	0		4851	0			8226	0	
CRITICAL I Starts				August 16, 1928			September 1, 1943				October 1, 1936		
Ends				February 29, 1932			April 30, 1945				April 15, 1937		
Length (Months)				42.5 Months			20 Months				6.5 Months		
Study Identification				02-41			02-42				02-13		

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

2/ From Tables 1 and 3.

3/ Peak reserves for Step I, II, III are 8 percent of January peak load from Table 3. Energy reserve deductions only include the hydro maintenance for Step I study (reserves have been included in thermal plant energy capability) from Table 1A, line 7(a).

4/ Step I energy load from Table 1A, line 5 and January peak load from Table 1B, line 5. Step II & III energy load from Table 3. Step II & III peak load is equal to the step II or step III annual average load multiplied by the ratio of the PNWA January peak load to the PNW annual average load.

TABLE 5
(English & Metric Units)
COMPUTATION OF CANADIAN ENTITLEMENT FOR 2001-02 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S. (From 02-42)
B. Optimum Power Generation in the U.S. Only (From 02-12)
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 02-22)

	CAPACITY ENTITLEMENT		
Determination of Dependable Capacity Credited to Canadian Storage (MW)	(A)	(B)	(C)
Step II - Critical Period Average Generation 1/	9055.6	9055.6	9018.7
Step III - Critical Period Average Generation 2/	6865.3	6865.3	6865.3
Gain Due to Canadian Storage	2190.3	2190.3	2153.4
Average Critical Period Load Factor in percent 3/	76.74	76.74	76.74
Dependable Capacity Gain 4/	2854.2	2854.2	2806.1
Canadian Share of Dependable Capacity 5/	1427.1	1427.1	1403.0

	ENERGY ENTITLMENT		
Determination of Increase in Average Annual Usable Energy (aMW)			
Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Annual Firm Hydro Energy 6/	8966.5	8966.5	8930.0
Thermal Displacement Energy 7/	2306.6	2304.3	2311.5
Other Usable Secondary Energy 8/	135.8	137.4	143.8
System Annual Average Usable Energy	11408.9	11408.2	11385.3
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6573.9	6573.9	6573.9
Thermal Displacement Energy 7/	3294.0	3294.0	3294.0
Other Usable Secondary Energy 8/	475.9	475.9	475.9
System Annual Average Usable Energy	10343.8	10343.8	10343.8
Average Annual Usable Energy Gain 9/	1065.1	1064.4	1041.5
Canadian Share of Average Annual Energy Gain 5/	532.6	532.2	520.8

1/ Step II values were obtained from the 02-42, 02-12, and 02-22 studies, respectively.
2/ Step III values were obtained from the 02-13 study and Table 3.
3/ Critical period load factor from Table 3.
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.

TABLE 6
(English & Metric Units)
COMPARISON OF RECENT DDPB STUDIES

	1997-98	1998-99	1999-00	2000-01	2001-02
AVERAGE PNWA ENERGY LOAD					
Annual Load (MW)	20387.3	20479.6	20817.8	21107.8	21641.7
Annual/January Load (%)	86.9	86.3	85.9	87.4	88.0
Critical Period (CP) Load Factor (%)	75.2	75.6	75.3	75.1	76.7
Annual Firm Exports	926.3	1075.3	1202.7	1067.1	1156.3
Annual Firm Surplus (MW) 1/	433.2	534.6	708.1	739.7	313.7
THERMAL INSTALLATIONS (MW) 2/					
January Peak Capability	10514	11003	11341	11520	11433
CP Energy	8141	8462	9019	9521	9496
CP Minimum Generation	632	789	1071	858	853
Average Annual System Export Sales	1133	1265	1392	1413	997
Average Annual Displaceable Market	6105	6345	6490	7179	7493
HYDRO CAPACITY (MW)					
Total Installed	29786	29786	29786	29836	29827
Base System	23856	23856	23856	23889	23880
STEP I/II/III CP (MONTHS)	42/20/6	42/20/6.5	42/20/7	42/20/7	42.5/20/6.5
BASE STREAMFLOWS AT THE DALLES (cfs) 3/					
Step I 50-yr. Average Streamflow	180748	181664	181664	181663	181663
Step I CP Average	114127	114496	114496	114496	114401
Step II CP Average	101008	101537	101525	101525	101525
Step III CP Average	64870	58483	64960	64959	58482
BASE STREAMFLOWS AT THE DALLES (m^3/s) 3/					
Step I 50-yr. Average Streamflow	5118.20	5144.15	5144.15	5144.12	5144.12
Step I CP Average	3231.71	3242.16	3242.16	3242.16	3239.46
Step II CP Average	2860.22	2875.20	2874.86	2874.86	2874.86
Step III CP Average	1836.92	1656.05	1839.46	1839.43	1656.01
CAPACITY BENEFITS (MW)					
Step II CP Generation	9018.0	9064.1	9080.4	9032.9	9055.6
Step III CP Generation	7169.4	6773.9	6878.8	6859.6	6865.3
Step II Gain over Step III	1848.6	2290.2	2201.7	2173.3	2190.3
CANADIAN ENTITLEMENT	1229.6	1514.7	1461.9	1447.3	1427.1
Change due to Mica Reoperation	0.0	-0.4	0.2	0.0	0.0
Benefit in Sales Agreement	471.0	416.0	200.0	192.0	187.0
ENERGY BENEFITS (aMW)					
Step II Annual Firm Hydro	8963.0	9000.0	8990.3	8967.3	8966.5
Step II Thermal Displacement	2037.7	2101.3	2129.5	2183.3	2306.6
Step II Other Usable Secondary	194.9	188.3	193.5	148.7	135.8
Step II System Annual Average Usable	11195.6	11289.6	11313.3	11299.3	11408.9
Step III Annual Firm Hydro	6579.0	6502.1	6422.2	6541.1	6573.9
Step III Thermal Displacement	2902.9	3066.8	3182.0	3239.8	3294.0
Step III Other Usable Secondary	607.2	595.3	590.1	501.5	475.9
Step III System Annual Average Usable	10089.1	10164.2	10194.3	10282.4	10343.8
CANADIAN ENTITLEMENT	553.3	562.7	559.5	508.4	532.6
Change due to Mica Reoperation	-2.8	-4.1	-0.8	0.7	0.4
ENTITLEMENT in Sales Agreement	246.0	215.0	103.0	99.0	95.0
STEP II PEAK CAPABILITY (MW)	31647	32074	32421	32481	32501
STEP II PEAK LOAD (MW)	26587	27317	28386	28779	27650
STEP III PEAK CAPABILITY (MW)	31456	31793	32206	32268	32260
STEP III PEAK LOAD (MW)	22859	23391	24318	24983	24034

FOOTNOTES FOR TABLE 6

1. Average annual firm surplus is the additional shaped load including the surplus shaped in the following periods:

AOP Study	Amount Shaped (MW)
1997-98	3000 May and
	2171 June.
1998-99	3199 May and June.
1999-00	4237 May and June.
2000-01	471 1 August through 30 April and
	1537 May through July.
2001-02	1877 May and June.

2. Thermal installations include thermal imports, all existing and planned thermal resources, combustion turbines, cogeneration, renewable thermal, thermal NUG/PURPA, minus seasonal exchange imports and plant sales.

3. The 1990 level modified flows were used and no additional irrigation depletions were anticipated for the 2001-02 level. There is, however, an adjustment for Grand Coulee pumping and return flow.

CHART 1

2001-02 DDBP STUDY

DURATION CURVES OF 30 YEAR MONTHLY HYDRO GENERATION (aMW)