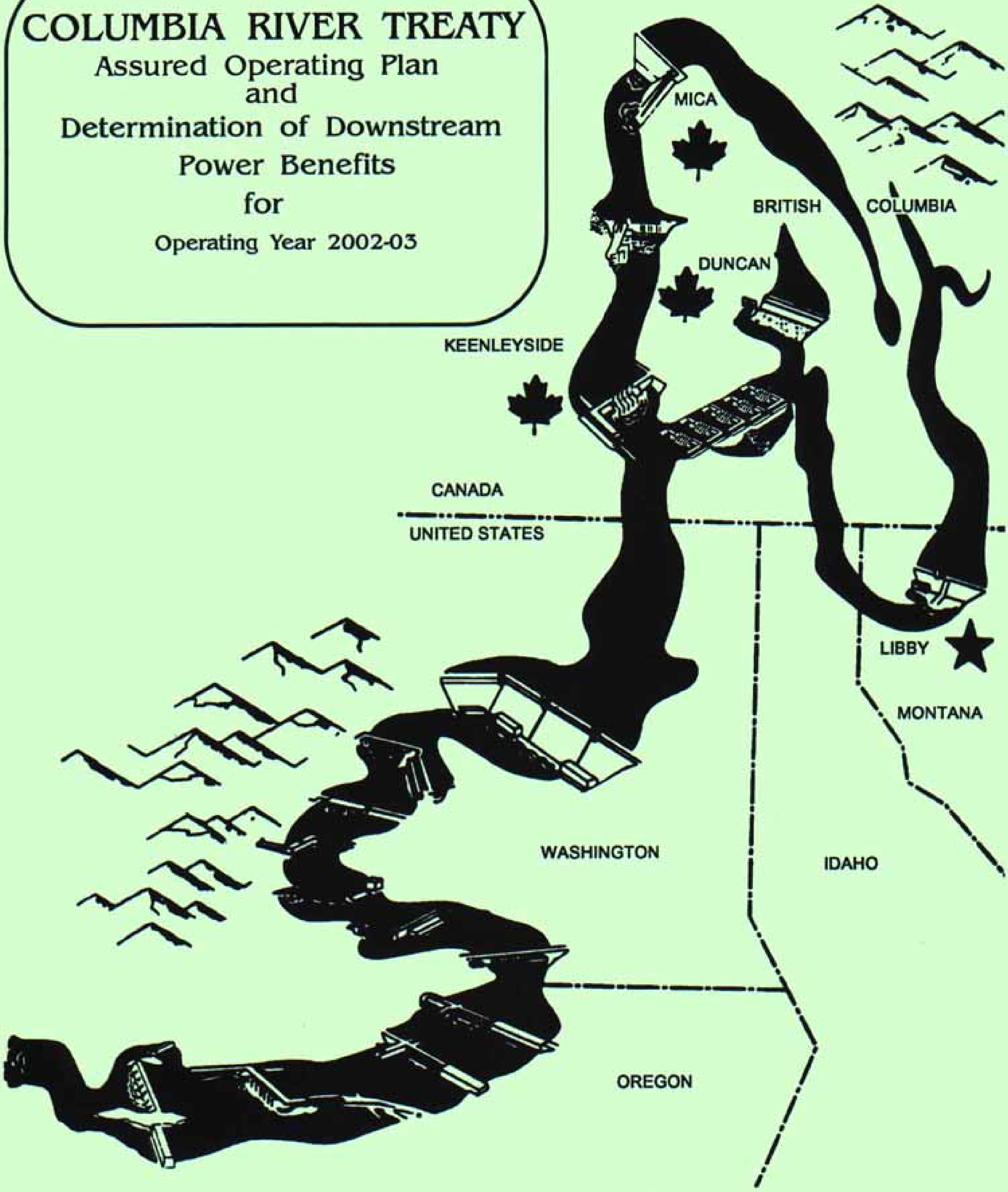
COLUMBIA RIVER TREATY

Assured Operating Plan and Determination of Downstream Power Benefits for

Operating Year 2002-03



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 2002-03 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 2002-03" and "Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2002-03," both dated January 2000, shall be the Assured Operating Plan and Determination of Downstream Power Benefits for the Operating Year 2002-03.

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 2002-03

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HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN FOR OPERATING YEAR 2002-03

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, 1999-00, 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 do 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 2002-03 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 2002-03 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 2002-03 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 2002-03 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 2002-03 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 2002-03 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 1.7 aMW increase in the Canadian Entitlement for average annual usable energy and 0.7 MW decrease in the dependable capacity compared to an operation for optimum generation in the United States alone.

Since there is no reduction in the energy entitlement and only a slight decrease in capacity 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 2002-03 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 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 2002-03, 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's. 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; and operating rules and constraints, such as maximum and minimum project elevations, discharges, and draft rates. 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 2002-03 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 power 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 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 2002-03 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 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 2002-03 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 2002-03 DOP. Failing agreement on updating the data and/or criteria, the 2002-03 DOP will include the rule curves, Mica operating criteria, and other data and criteria provided in this AOP. Actual operation during the 2002-03 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, 1 April 1999, and 1 April 2003 the portions of the Canadian Entitlement to downstream power benefits attributed to the operation of Duncan, Arrow, and Mica 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] 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, and all the Canadian Entitlement to downstream power benefits will be returned to Canada starting 1 April 2003.

(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 2002 through 31 July 2003 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. An explanation of the more important changes compared to last year's studies follows.

(a) Loads and Non-Hydro Resources

Loads for the 2002-03 AOP were based on the final 1996 Whitebook medium case forecast developed by BPA in 31 December 1996. Compared to the previous AOP, the Pacific Northwest Area (PNWA) firm energy load increased by 128 aMW. Other load changes include:

- It was assumed that one-half of the Entitlement was exported to B.C. and three-eighths was used to meet load in the PNWA, and one-eighth was exported to the Southwest. This was a decrease of 43 aMW in the Canadian Entitlement returned to the PNWA compared to the 2001-02 AOP study, which modeled all of the Entitlement exported to Canada, and one-half of the Entitlement imported into the Region.

- There were new exports to BART, SCE, M-S-R, Turlock Irrigation District share of Boardman, and New Energy Venture.

- Exports to SCE Power, Utah, and WAPA were terminated.

- The average annual firm surplus increased by only 10 aMW and was again shaped into May and June (1937 aMW in May and June for the 2002-03 AOP vs. 1877 aMW in May and June in the 2001-02 AOP).

There was a clarification and modification of the thermal installations for this study (see Table 1A and Table 2 of DDPB document). The total annual energy capability of the thermal installations increased by 576 aMW due to the following changes:

- Large Thermal resources increased by 235 aMW (127 aMW from WNP2, 56 aMW from Centralia, 69 aMW from Colstrip 4, and 17 aMW less from Broadman Coal);

- Cogeneration decreased by 11 aMW;

- Thermal PURPA/NUGS decreased by 27 aMW;
- Increased Plant Sales reduced the Thermal Installations by 39 aMW; and
- Thermal Imports increased by 416 aMW mostly due to an increase in the Thermal Import from Pacificorp, and the shaping of the thermal capability. All of the SW imports were not included as Thermal Installations this year since a specific thermal project was not identified.

(b) Operating Procedures

Plant data tables for Packwood, Trail Bridge, and Carmen projects were removed so that these projects were modeled as hydro independents in the 2002-03 AOP study. Plant data tables for Monroe, Gorge, Diablo, Ross, Mayfield, and Lagrande were updated. Also, Mica full storage content was changed to 6087.9 ksfd (14894.7 hm^3) from 6073.0 ksfd (14858.2 hm^3), adjusted by 14.9 ksfd (36.5 hm^3).

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 in non-power requirements for non-base and base system projects from the previous studies included:

Non-base System Projects

- Dworshak minimum flow requirement decreased to 1300 cfs (36.81 m^3/s) from 1500 cfs (42.48 m^3/s) in all periods.
- Gorge minimum flow requirement decreased to 1800 cfs (50.97 m^3/s) in February-30 April, to 1500 cfs (42.48 m^3/s) in May-July, and November-January due to The Skagit Fisheries Settlement.
- Mayfield maximum flow requirement decreased to 7000 cfs (198.22 m^3/s) in September, and to 6000 cfs (169.90 m^3/s) in November.
- Little Falls new minimum flow requirement is 200 cfs (5.67 m^3/s) when Grand Coulee's elevation is greater than 1281 ft (390.45 m), and 500 cfs (14.16 m^3/s) when equal or less than 1281 ft (390.45 m).
- Lower Monumental, Little Goose, and Lower Granite spill cap increased to 20000 cfs (566.34 m^3/s), 25000 cfs (707.92 m^3/s), and 22500 cfs (637.13 m^3/s) respectively. Spill terminated at Lower Granite if it's regulated outflow is less than 100000 cfs (2831.68 m^3/s). Likewise, spill terminated at Lower Monumental and Little Goose if Lower Granite's regulated outflow is less than 85000 cfs (2406.93 m^3/s).

- Mossyrock was regulated to a rule curve operation instead of the fixed power regulation in the previous AOP due to significant changes to minimum and maximum storage requirements.

- Minor changes in fixed flood control at Mossyrock, Long Lake, CDA Lake, Noxon, Lower Baker, Upper Baker, Ross, and White projects.

Base System Projects

- Grand Coulee pumping minimum elevation requirement in both May and June of 1240 ft (377.95 m) 843.9 ksfd (2064.7 hm^3) instead of May only.

- John Day was operated to be consistent with the 1979-80 AOPs:
  268.0 ft (81.69 m) 269.7 ksfd (659.9 hm^3) in June–15 August;
  267.0 ft (81.38 m) 242.5 ksfd (593.3 hm^3) in 31 August–September;
  263.6 ft (80.35 m) 153.7 ksfd (376.0 hm^3) in October–March; and
  262.0 ft (79.86 m) 114.9 ksfd (281.1 hm^3) in 15 April–May.

John Day was operated to 265.0 ft (80.77 m) 190.0 ksfd (464.9 hm^3) during all periods in the 2001-02 AOP study.

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, 1999-00, 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 03-41," dated 13 April 1998.

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
2002-03 ASSURED OPERATING PLAN

Period	End of Previous Period Arrow Storage Content (ksfd)	------- Target Operation ------- Period Average Outflow (cfs)	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	29000			
August 16-31	3400 - FULL	-	3529.2	15000	0.0
	1450 - 3400	21000			
	0 - 1450	30000			
September	3460 - FULL	-	3529.2	10000	0.0
	1870 - 3460	22000			
	740 - 1870	24000			
	0 - 740	32000			
October	3225 - FULL	-	3396.2	10000	0.0
	2530 - 3225	21000			
	1840 - 2530	23000			
	0 - 1840	32000			
November	3280 - FULL	20000		12000	0.0
	2610 - 3280	22000			
	830 - 2610	24000			
	0 - 830	32000			
December	3290 - FULL	22000		21000	341.3
	1895 - 3290	25000			
	1000 - 1895	27000			
	0 - 1000	30000			
January	2980 - FULL	24000		15000	91.3
	2060 - 2980	26000			
	2020 - 2060	24000			
	0 - 2020	28000			
February	1810 - FULL	21000		15000	0.0
	780 - 1810	23000			
	190 - 780	25000			
	0 - 190	23000			
March	1570 - FULL	18000		15000	0.0
	1290 - 1570	24000			
	1070 - 1290	20000			
	0 - 1070	27000			
April 1-15	1690 - FULL	-	281.3	13000	0.0
	1300 - 1690	-	0.0		
	800 - 1300	18000			
	0 - 800	-	26.3		
April 16-30	980 - FULL	15000	-	14000	0.0
	755 - 980	13000	-		
	735 - 755	-	0.0		
	0 - 735	10000			
May	340 - FULL	10000		8000	0.0
	245 - 340	8000			
	150 - 245	16000			
	0 - 150	20000			
June	1480 - FULL	10000		8000	0.0
	1070 - 1480	8000			
	480 - 1070	12000			
	0 - 480	18000			
July	1940 - FULL	-	3456.2	8000	0.0
	1820 - 1940	19000			
	1700 - 1820	12000			
	0 - 1700	27000			

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 16-30, May, and June. For these periods, the maximum outflow is 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 2002-03 ASSURED OPERATING PLAN
STUDY RESULTS

Study 03-41 provides Optimum Generation in Canada and in the United States.
Study 03-11 provides Optimum Generation in the United States only.

	Study No. 03-41	Study No. 03-11	Net Gain	Weight	Value
1. Firm Energy Capability (aMW)					
U.S. System 1/	12064.8	12065.1	-0.3		
Canada 2/, 3/	2828.4	2798.1	30.3		
Total	14893.2	14863.2	30.0	3	90.0
2. Dependable Peaking Capacity (MW)					
U.S. System 4/	31108.0	31126.0	-18.0		
Canada 2/, 5/	5617.0	5591.0	26.0		
Total	36725.0	36717.0	8.0	1	8.0
3. Average Annual Usable Secondary Energy (aMW)					
U.S. System 6/	3183.0	3179.3	3.7		
Canada 2/, 7/	239.1	256.4	-17.3		
Total	3422.1	3435.7	-13.6	2	-27.2
			Net Change in Value =		70.8

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)
2002 - 03 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	3529.2	3527.6	3526.5	3332.0	3110.4	2842.9	1887.4	1554.6	1448.8	733.7	83.0	543.3	2190.7	3354.3
1929-30	3495.6	3454.1	3262.5	2864.9	2229.8	1815.4	700.8	693.2	645.3	89.9	75.2	494.9	1786.0	2847.1
1930-31	3032.8	3058.0	2898.8	2652.3	2077.4	1476.1	501.0	489.6	496.4	31.0	0.0	160.3	1257.6	1815.8
1931-32	1809.7	1697.2	1484.6	1153.0	588.4	151.3	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	3579.6	3578.0	3576.9	3356.5	3133.3	2550.2	1714.4	1295.9	1136.9	577.8	380.7	1034.0	2566.3	3368.5
1929-30	3544.8	3502.7	3308.4	2885.4	2268.1	1628.1	626.3	665.0	670.9	424.7	400.5	884.0	1906.5	2908.2
1930-31	3096.6	3101.0	3079.7	2671.2	2188.5	1384.0	514.4	415.5	430.2	181.6	13.5	394.0	1288.6	1841.5
1931-32	1835.2	1698.4	1334.8	1194.7	604.7	193.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	705.8	705.5	701.6	685.9	640.3	418.0	234.6	158.3	146.2	141.1	137.0	250.0	524.0	704.0
1929-30	702.4	690.8	655.8	593.2	440.0	269.5	84.0	74.8	57.7	67.5	77.2	90.6	280.0	497.6
1930-31	564.1	618.2	578.6	532.7	427.7	217.0	61.0	45.8	57.7	57.4	57.1	18.8	192.3	346.1
1931-32	368.9	336.7	312.0	160.0	70.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	7814.6	7811.1	7805.0	7374.4	6884.0	5811.1	3836.4	3008.8	2731.9	1452.6	600.7	1827.3	5281.0	7426.8
1929-30	7742.8	7647.6	7226.7	6343.5	4937.9	3713.0	1411.1	1433.0	1373.9	582.1	552.9	1469.5	3972.5	6252.9
1930-31	6693.5	6777.2	6557.1	5856.2	4693.6	3077.1	1076.4	950.9	984.3	270.0	70.6	573.1	2738.5	4003.4
1931-32	4013.8	3732.3	3131.4	2507.7	1263.1	344.9	0.5	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
2002 - 03 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	562.0	1126.2	1729.5	1907.8	1973.1	1989.6	1984.4	1973.0	1824.8	1670.0	1403.2	1498.1	2553.4	3529.2
VARIABLE REFILL CURVES (KSFD)**														
1928-29							3010.5	2755.0	2560.7	2386.2	2247.0	2165.4	2807.3	3529.2
1929-30							1986.2	1691.4	1487.6	1331.2	1307.7	1558.2	2523.1	"
1930-31							2245.8	1959.9	1751.5	1573.4	1483.5	1578.1	2598.3	"
1931-32							406.5	267.8	221.1	223.7	338.8	1041.8	2416.8	"
1932-33							300.2	196.9	167.5	168.0	238.8	939.1	2253.4	"
1933-34							0.0	0.0	0.0	0.0	0.0	687.4	2506.1	"
1934-35							1158.3	981.8	904.4	855.0	836.8	1238.8	2356.0	"
1935-36							1071.9	879.6	775.5	687.8	680.0	1206.9	2621.1	"
1936-37							2998.7	2722.6	2513.6	2328.3	2237.0	2179.0	2839.6	"
1937-38							680.1	558.3	511.6	518.7	602.6	1265.1	2508.3	"
1938-39							2049.9	1832.4	1638.0	1485.8	1417.1	1601.4	2831.1	"
1939-40							1834.7	1575.6	1398.4	1240.0	1189.5	1396.1	2590.9	"
1940-41							2427.7	2162.7	1973.8	1815.1	1812.4	1955.0	2821.1	"
1941-42							1669.9	1493.7	1390.9	1312.9	1300.3	1659.3	2685.6	"
1942-43							1288.4	1144.4	1099.4	1097.2	1249.7	1892.4	2746.7	"
1943-44							3111.0	2814.2	2618.8	2436.7	2325.2	2285.3	2978.3	"
1944-45							2897.8	2656.8	2490.5	2342.6	2226.8	2188.8	2891.2	"
1945-46							72.0	0.0	0.0	0.0	0.0	737.7	2411.2	"
1946-47							222.1	123.7	104.1	115.9	222.0	1002.1	2481.7	"
1947-48							139.4	20.3	0.0	0.0	51.2	797.6	2368.4	"
1948-49							1893.1	1748.5	1686.8	1684.3	1742.8	2173.4	3139.9	"
1949-50							494.9	336.3	277.9	268.4	352.9	1018.7	2179.7	"
1950-51							486.1	375.2	348.8	357.1	470.6	1137.8	2541.2	"
1951-52							892.9	739.4	687.5	672.4	753.7	1433.2	2688.5	"
1952-53							1205.2	1069.6	1027.2	1024.9	1074.1	1588.4	2655.4	"
1953-54							49.9	0.0	0.0	0.0	0.0	713.7	2151.8	"
1954-55							901.3	793.8	767.9	778.2	834.5	1359.5	2346.2	"
1955-56							358.0	233.0	186.3	179.4	267.8	1035.7	2455.7	"
1956-57							526.6	394.3	362.2	367.6	456.6	1121.9	2786.3	"
1957-58							386.6	267.2	241.6	252.3	348.8	1018.6	2548.8	"
LIMITING RULE CURVE (KSFD)							365.0	233.2	29.8	0.0				

**Not include Limiting Rule Curve. Prior AOPs the Variable Refill Curves included the Limiting Rule Curve.

	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	3000	8000	15000	25000	25000	25000	25000
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
80 MAF --							3000	8000	8000	15000	15000	20000	21000	21000
95 MAF --							3000	3000	3000	3000	5000	5000	15000	19000
110 MAF --							3000	3000	3000	3000	3000	3000	15000	19000

TABLE 5
(English Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2002 - 03 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	0.0	0.0	406.2	901.1	1257.2	1577.2	2480.0	2430.2	2195.7	1911.0	1885.3	2506.5	3390.2	3579.6
VARIABLE REFILL CURVES (KSFD)**														
1928-29							3491.1	2984.3	2685.2	2602.4	2798.8	3224.6	3515.5	3579.6
1929-30							1862.9	1663.4	1511.5	1463.0	1626.7	2625.4	3335.1	..
1930-31							2330.2	1826.8	1616.6	1577.6	1740.6	2462.8	3318.2	..
1931-32							530.9	460.3	505.5	682.3	887.4	1741.4	2954.9	..
1932-33							1203.5	1178.1	1188.0	1184.5	1275.1	1911.6	2899.1	..
1933-34							0.0	12.6	231.5	422.7	827.1	2320.5	3362.2	..
1934-35							1422.1	1343.8	1352.5	1344.8	1432.0	2115.3	3008.0	..
1935-36							1471.5	1283.6	1123.8	1056.1	1114.1	2087.3	3327.3	..
1936-37							3579.6	3251.4	2951.2	2829.5	3041.2	3408.1	3579.6	..
1937-38							1805.7	1753.2	1731.5	1759.3	1850.8	2387.9	3198.7	..
1938-39							2062.4	1742.3	1529.1	1464.4	1625.3	2546.6	3579.6	..
1939-40							1729.3	1520.3	1362.2	1411.1	1607.6	2432.0	3384.4	..
1940-41							2962.8	2498.8	2266.0	2321.7	2817.8	3501.4	3579.6	..
1941-42							2586.9	2465.0	2370.6	2315.3	2422.1	3009.2	3546.8	..
1942-43							3007.2	2893.9	2832.9	2799.8	2843.0	3524.9	3579.6	..
1943-44							3579.6	3579.6	3532.8	3420.4	3579.6	3579.6	3579.6	..
1944-45							3576.4	3140.8	2927.0	2883.2	3078.0	3434.3	3579.6	..
1945-46							941.8	832.6	952.3	982.1	1176.1	1907.3	3106.8	..
1946-47							1552.6	1448.8	1520.8	1534.6	1659.0	2295.1	3192.5	..
1947-48							1289.6	1203.5	1337.0	1328.9	1396.6	1986.8	3108.6	..
1948-49							2054.8	1962.9	1943.2	1925.2	2355.4	3220.1	3579.6	..
1949-50							1429.2	1338.9	1326.9	1336.3	1402.1	1927.5	2780.7	..
1950-51							1717.7	1675.5	1670.6	1646.8	1750.9	2266.1	3270.9	..
1951-52							1766.4	1679.7	1659.2	1641.8	1693.9	2321.0	3375.3	..
1952-53							2135.9	2053.9	2028.4	2006.1	2041.4	2533.1	3322.1	..
1953-54							635.8	586.8	792.6	851.4	1001.8	1616.5	2768.8	..
1954-55							1432.7	1408.4	1409.9	1353.8	1461.1	1986.0	2749.8	..
1955-56							1173.6	1114.9	1094.0	1098.3	1189.9	1969.2	3106.7	..
1956-57							1232.9	1149.4	1119.7	1112.7	1209.8	1811.9	3472.0	..
1957-58							1030.6	958.2	973.5	1034.7	1194.2	1840.0	3131.8	..
LIMITING RULE CURVE (KSFD)							337.7	198.1	25.9	0.0				

**Not include Limiting Rule Curve. Prior AOPs the Variable Refill Curves included the Limiting Rule Curve.

POWER DISCHARGE REQUIREMENTS (CFS):	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVES	5000	5000	5000	5000	5000	5000	5000	8000	20000	40000	40000	45000	50000	51000
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
80 MAF --							5000	15000	15000	20000	22000	28000	43000	45000
95 MAF --							5000	5000	5000	8000	13000	23000	43000	45000
110 MAF --							5000	5000	5000	5000	13000	23000	43000	45000

TABLE 6
(English Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2002 - 03 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	80.3	151.2	217.5	248.2	265.7	276.9	287.1	285.1	255.8	248.0	240.2	354.0	540.9	705.8
VARIABLE REFILL CURVES (KSFD)**														
1928-29							431.2	427.2	424.2	422.8	431.7	498.5	620.0	705.8
1929-30							429.6	425.2	421.9	420.2	443.3	519.0	631.5	..
1930-31							374.1	371.0	371.3	374.6	389.2	468.5	620.0	..
1931-32							60.5	58.7	66.3	74.5	116.1	278.8	525.8	..
1932-33							0.0	0.0	0.0	0.0	0.0	103.1	391.1	..
1933-34							46.7	62.0	75.0	89.2	159.5	338.3	583.9	..
1934-35							162.3	166.8	177.6	180.6	198.7	329.2	525.5	..
1935-36							116.4	115.5	116.1	116.9	137.1	302.8	560.3	..
1936-37							379.1	375.0	373.8	372.1	381.0	461.0	602.1	..
1937-38							130.5	136.0	141.5	148.7	178.6	334.0	550.4	..
1938-39							226.0	228.5	231.0	233.2	255.6	381.3	602.8	..
1939-40							209.3	217.2	227.1	238.9	262.9	383.4	591.3	..
1940-41							291.4	296.1	301.8	314.9	347.8	459.8	615.1	..
1941-42							269.4	276.4	282.4	286.6	307.5	423.8	591.2	..
1942-43							256.9	257.6	261.2	263.2	294.7	443.8	583.4	..
1943-44							447.4	448.7	450.6	451.2	462.3	531.2	650.2	..
1944-45							366.7	368.6	371.3	371.9	381.1	460.3	607.6	..
1945-46							2.7	0.3	3.7	6.0	39.1	225.2	519.2	..
1946-47							44.4	42.5	47.6	52.3	87.3	267.8	531.9	..
1947-48							83.1	85.9	92.1	93.5	120.2	284.7	542.3	..
1948-49							321.5	319.0	319.0	318.3	339.6	456.9	644.4	..
1949-50							114.8	113.5	116.3	116.2	140.7	293.3	486.3	..
1950-51							33.5	39.9	49.4	50.0	84.4	259.4	517.4	..
1951-52							144.3	144.4	150.4	151.8	178.6	343.4	562.6	..
1952-53							148.3	148.9	154.0	156.0	179.9	321.9	528.8	..
1953-54							0.0	0.0	0.0	0.0	9.0	187.3	459.3	..
1954-55							96.3	98.7	103.8	107.2	129.6	272.1	463.1	..
1955-56							0.0	0.0	0.0	1.6	33.1	233.3	515.1	..
1956-57							95.3	91.6	93.9	96.0	126.1	286.1	579.5	..
1957-58							8.5	8.1	14.8	19.4	50.6	224.1	531.3	..
LIMITING RULE CURVE (KSFD)							57.5	21.8	3.5	0.0				

**Not include Limiting Rule Curve. Prior AOPs the Variable Refill Curves included the Limiting Rule Curve.

	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	500	1500	1500	1500	1500	1800	2000
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
80 MAF --							100	100	100	100	800	1000	2800	3200
95 MAF --							100	100	100	100	300	500	2800	3000
110 MAF --							100	100	100	100	100	100	2800	3000

TABLE 7
(English Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2002 - 03 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)
2002 - 03 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)
2002 - 03 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)
2002 - 03 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7811.1	7805.0	7374.4	6884.0	5811.1	4751.5	4688.3	4276.3	3829.0	3528.7	4358.6	6484.5	7814.6
1929-30	"	"	"	"	"	"	4134.4	3639.9	3254.9	3042.2	3174.6	4358.6	6399.1	"
1930-31	"	"	"	"	"	"	4601.7	4071.8	3623.9	3399.0	3384.0	4314.9	6412.5	"
1931-32	"	"	"	"	"	"	997.9	786.8	792.1	980.5	1335.3	3062.0	5897.5	"
1932-33	"	"	"	"	"	"	1626.0	1433.1	1179.3	1176.3	1275.4	2803.9	5543.6	"
1933-34	"	"	"	"	"	"	760.2	493.3	326.8	488.2	954.1	3346.2	6409.2	"
1934-35	"	"	"	"	"	"	2742.7	2391.1	1978.2	1928.8	1928.6	3151.7	5852.1	"
1935-36	"	"	"	"	"	"	2659.8	2228.7	1849.3	1815.2	1913.4	3597.0	6421.6	"
1936-37	"	"	"	"	"	"	4751.5	4666.8	4276.3	3829.0	3528.7	4358.6	6484.5	"
1937-38	"	"	"	"	"	"	2616.3	2380.8	1622.2	1714.7	2000.1	3341.5	6196.8	"
1938-39	"	"	"	"	"	"	4272.8	3667.4	3259.8	3059.5	3161.1	4358.6	6484.5	"
1939-40	"	"	"	"	"	"	3773.3	3211.3	2876.0	2778.3	2948.0	4182.1	6478.7	"
1940-41	"	"	"	"	"	"	4751.5	4605.3	4222.6	3793.2	3517.8	4348.8	6468.1	"
1941-42	"	"	"	"	"	"	4302.8	3383.8	2569.1	2556.8	2651.6	3786.1	6484.5	"
1942-43	"	"	"	"	"	"	3908.8	3043.0	2286.1	2400.6	2792.8	3227.6	5483.4	"
1943-44	"	"	"	"	"	"	4751.5	4688.3	4276.3	3829.0	3528.7	4358.6	6484.5	"
1944-45	"	"	"	"	"	"	4751.5	4388.3	3726.1	3590.5	3387.5	4220.9	6441.8	"
1945-46	"	"	"	"	"	"	1364.3	1087.6	985.8	988.1	1215.2	2870.2	6037.2	"
1946-47	"	"	"	"	"	"	1975.1	1724.5	1160.0	1243.4	1669.9	3417.3	6206.1	"
1947-48	"	"	"	"	"	"	1737.7	1502.2	1103.6	1102.1	1299.9	3069.1	6017.9	"
1948-49	"	"	"	"	"	"	4235.0	3719.7	2946.1	3062.6	3019.4	4346.6	6484.5	"
1949-50	"	"	"	"	"	"	2038.9	1740.7	1351.7	1342.2	1426.7	2316.4	4898.3	"
1950-51	"	"	"	"	"	"	2261.3	2090.6	1406.5	1415.4	1544.4	2752.7	6329.5	"
1951-52	"	"	"	"	"	"	2803.6	2484.6	1761.3	1807.9	2166.3	3318.2	5822.3	"
1952-53	"	"	"	"	"	"	3489.4	2855.3	2101.0	2154.0	2331.7	3209.0	6090.0	"
1953-54	"	"	"	"	"	"	1058.3	841.8	825.9	851.4	1010.8	2517.5	4509.1	"
1954-55	"	"	"	"	"	"	2430.3	2267.7	1841.7	1925.3	2006.0	3167.7	5559.1	"
1955-56	"	"	"	"	"	"	1596.1	1369.9	1198.1	1189.3	1490.8	3238.2	5964.2	"
1956-57	"	"	"	"	"	"	1854.8	1609.2	1436.0	1519.9	1756.3	3219.9	6484.5	"
1957-58	"	"	"	"	"	"	1474.7	1247.2	1229.9	1306.4	1590.3	3082.7	6211.9	"

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

	1998-99	1999-00	2000-01	2001-02	2002-03
MICA TARGET OPERATION					
(ksfd[xxxx.x] or cfs [xxxxx])					
AUG 15	3456.2	3456.2	3486.2	3486.2	3486.2
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	11000	3428.2	3386.2	3396.2	3396.2
NOV	3256.2	3176.2	3056.2	20000	20000
DEC	2676.2	24000	25000	22000	22000
JAN	24000	25000	26000	24000	24000
FEB	22000	22000	23000	21000	21000
MAR	22000	21000	22000	22000	18000
APR 15	86.2	156.2	26000	326.2	281.3
APR 30	56.2	106.2	106.2	56.2	15000
MAY	10000	10000	8000	10000	10000
JUN	10000	10000	8000	10000	10000
JUL	3406.2	3456.2	3456.2	3456.2	3456.2
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (ksfd)					
1928 AUG 31	7814.6	7814.6	7814.6	7806.2	7811.1
1928 DEC	6250.9	5618.4	5402.7	5310.4	5811.1
1929 APR15	1676.3	1763.1	1597.9	1458.7	1452.6
1929 JUL	7005.8	6916.0	7116.1	7453.0	7426.8
COMPOSITE CANADIAN TREATY STORAGE CONTENT (ksfd)					
50-yr Average for AOP99~AOP02, 60-yr average for AOP03					
AUG 31	7323.8	7295.4	7389.8	7412.3	7414.6
DEC	5584.3	5283.1	5157.8	5236.9	5226.9
APR15	888.6	1424.0	1150.7	1135.3	1173.1
JUL	7110.7	7099.3	7273.7	7358.2	7339.0
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-5.1	-1.5	-0.3	0.2	-0.3
U.S. Dependable Peaking Capacity	27.0	0.0	-2.0	0.0	-18.0
U.S. Average Annual Usable Secondary Energy	18.9	19.5	16.2	24.9	3.7
BCH Firm Energy	26.7	102.2	60.8	48.3	30.3
BCH Dependable Peaking Capacity	18.0	-3.0	-36.0	25.0	26.0
BCH Average Annual Usable Secondary Energy	-18.5	-42.9	-43.6	-29.7	-17.3
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	10083	9793	10043	10422	10368
AUG 31	10203	9925	10125	10439	10355
SEP	9957	9630	10095	10434	9911
OCT	9963	9764	10046	10388	10051
NOV	11305	11297	11381	11626	11716
DEC	12787	12766	12836	13012	13160
JAN	13640	13725	13484	13382	13707
FEB	12638	12674	12765	12502	12694
MAR	11994	12113	11807	11667	11858
APR 15	11671	11099	11332	11187	11460
APR 30	12425	12672	13025	12575	13101
MAY	15701	17263	14347	14647	14357
JUN	14662	14699	11925	12590	13324
JUL	10594	9894	11275	10493	10457
ANNUAL AVERAGE	12117	12131	11850	11919	11986

TABLE 1M
(Metric Units)
MICA PROJECT OPERATING CRITERIA
2002-03 ASSURED OPERATING PLAN

Period	End of Previous Period Arrow Storage Content (hm^3)	Target Operation: Period Average Outflow (m^3/s)	Target Operation: 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	424.8	0.0
	4036.9 - 6361.2	453.07			
	0.0 - 4036.9	821.19			
August 16-31	8318.4 - FULL	-	8634.5	424.8	0.0
	3547.6 - 8318.4	594.65			
	0.0 - 3547.6	849.50			
September	8465.2 - FULL	-	8634.5	283.2	0.0
	4575.1 - 8465.2	622.97			
	1810.5 - 4575.1	679.60			
	0.0 - 1810.5	906.14			
October	7890.3 - FULL	-	8309.1	283.2	0.0
	6189.9 - 7890.3	594.65			
	4501.7 - 6189.9	651.29			
	0.0 - 4501.7	906.14			
November	8024.8 - FULL	566.34		339.8	0.0
	6385.6 - 8024.8	622.97			
	2030.7 - 6385.6	679.60			
	0.0 - 2030.7	906.14			
December	8049.3 - FULL	622.97		594.7	835.0
	4636.3 - 8049.3	707.92			
	2446.6 - 4636.3	764.55			
	0.0 - 2446.6	849.50			
January	7290.9 - FULL	679.60		424.8	223.4
	5040.0 - 7290.9	736.24			
	4942.1 - 5040.0	679.60			
	0.0 - 4942.1	792.87			
February	4428.3 - FULL	594.65		424.8	0.0
	1908.3 - 4428.3	651.29			
	464.9 - 1908.3	707.92			
	0.0 - 464.9	651.29			
March	3841.2 - FULL	509.70		424.8	0.0
	3156.1 - 3841.2	679.60			
	2617.9 - 3156.1	566.34			
	0.0 - 2617.9	764.55			
April 1-15	4134.8 - FULL	-	688.2	368.1	0.0
	3180.6 - 4134.8	-	0.0		
	1957.3 - 3180.6	509.70			
	0.0 - 1957.3	-	64.3		
April 16-30	2397.7 - FULL	424.75		396.4	0.0
	1847.2 - 2397.7	368.12			
	1798.3 - 1847.2		0.0		
	0.0 - 1798.3	283.17			
May	831.8 - FULL	283.17		226.5	0.0
	599.4 - 831.8	226.53			
	367.0 - 599.4	453.07			
	0.0 - 367.0	566.34			
June	3621.0 - FULL	283.17		226.5	0.0
	2617.9 - 3621.0	226.53			
	1174.4 - 2617.9	339.80			
	0.0 - 1174.4	509.70			
July	4746.4 - FULL	-	8455.9	226.5	0.0
	4452.8 - 4746.4	538.02			
	4159.2 - 4452.8	339.80			
	0.0 - 4159.2	764.55			

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 16-30, May, and June. For these periods, the maximum outflow is 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)
2002 - 03 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	8634.5	8630.6	8627.9	8152.1	7609.9	6955.4	4617.7	3803.5	3544.6	1795.1	203.1	1329.2	5359.8	8206.6
1929-30	8552.3	8450.8	7982.0	7009.3	5455.4	4441.6	1714.6	1696.0	1578.8	219.9	184.0	1210.8	4369.6	6965.7
1930-31	7420.0	7481.7	7092.2	6489.1	5082.6	3611.4	1225.7	1197.9	1214.5	75.8	0.0	392.2	3076.8	4442.5
1931-32	4427.6	4152.4	3632.2	2820.9	1439.6	370.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	8757.8	8753.9	8751.2	8212.0	7665.9	6239.3	4194.5	3170.5	2781.5	1413.6	931.4	2529.8	6278.7	8241.4
1929-30	8672.7	8569.7	8094.3	7059.4	5549.1	3983.3	1532.3	1627.0	1641.4	1039.1	979.9	2162.8	4664.4	7115.2
1930-31	7576.1	7586.9	7534.8	6535.4	5354.4	3386.1	1258.5	1016.6	1052.5	444.3	33.0	964.0	3152.7	4505.4
1931-32	4490.0	4155.3	3265.7	2923.0	1479.5	472.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	1726.8	1726.1	1716.5	1678.1	1566.6	1022.7	574.0	387.3	357.7	345.2	335.2	611.7	1282.0	1722.4
1929-30	1718.5	1690.1	1604.5	1451.3	1076.5	659.4	205.5	183.0	141.2	165.1	188.9	221.7	685.0	1217.4
1930-31	1380.1	1512.5	1415.6	1303.3	1046.4	530.9	149.2	112.1	141.2	140.4	139.7	46.0	470.5	846.8
1931-32	902.6	823.8	763.3	391.5	171.3	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	19119.2	19110.6	19095.7	18042.2	16842.4	14217.4	9386.1	7361.3	6683.9	3553.9	1469.7	4470.7	12920.5	18170.4
1929-30	18943.5	18710.6	17680.8	15520.0	12081.1	9084.2	3452.4	3506.0	3361.4	1424.2	1352.7	3595.3	9719.1	15298.3
1930-31	16376.3	16581.1	16042.6	14327.8	11483.4	7528.4	2633.5	2326.5	2408.2	660.6	172.7	1402.1	6700.0	9794.7
1931-32	9820.2	9131.4	7661.3	6135.3	3090.3	843.8	1.2	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
2002 - 03 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	1375.0	2755.4	4231.4	4667.6	4827.4	4867.8	4855.0	4827.1	4464.6	4085.8	3433.1	3665.3	6247.1	8634.5
VARIABLE REFILL CURVES (hm^3)**														
1928-29							7365.5	6740.4	6265.0	5838.1	5497.5	5297.9	6868.3	8634.5
1929-30							4859.4	4138.2	3639.6	3256.9	3199.4	3812.3	6173.0	..
1930-31							5494.6	4795.1	4285.2	3849.5	3629.5	3861.0	6357.0	..
1931-32							994.5	655.2	540.9	547.3	828.9	2548.9	5912.9	..
1932-33							734.5	481.7	409.8	411.0	584.2	2297.6	5513.2	..
1933-34							0.0	0.0	0.0	0.0	0.0	1681.8	6131.4	..
1934-35							2833.9	2402.1	2212.7	2091.8	2047.3	3030.8	5764.2	..
1935-36							2622.5	2152.0	1897.3	1682.8	1663.7	2952.8	6412.8	..
1936-37							7336.6	6661.1	6149.8	5696.4	5473.0	5331.1	6947.4	..
1937-38							1663.9	1365.9	1251.7	1269.1	1474.3	3095.2	6136.8	..
1938-39							5015.3	4483.1	4007.5	3635.2	3467.1	3918.0	6926.6	..
1939-40							4488.8	3854.9	3421.3	3033.8	2910.2	3415.7	6338.9	..
1940-41							5939.6	5291.3	4829.1	4440.8	4434.2	4783.1	6902.1	..
1941-42							4085.6	3654.5	3403.0	3212.1	3181.3	4059.6	6570.6	..
1942-43							3152.2	2799.9	2689.8	2684.4	3057.5	4629.9	6720.1	..
1943-44							7611.4	6885.2	6407.2	5961.6	5688.8	5591.2	7286.7	..
1944-45							7089.8	6500.1	6093.3	5731.4	5448.1	5355.1	7073.6	..
1945-46							176.2	0.0	0.0	0.0	0.0	1804.9	5899.2	..
1946-47							543.4	302.6	254.7	283.6	543.1	2451.7	6071.7	..
1947-48							341.1	49.7	0.0	0.0	125.3	1951.4	5794.5	..
1948-49							4631.7	4277.9	4126.9	4120.8	4263.9	5317.4	7682.1	..
1949-50							1210.8	822.8	679.9	656.7	863.4	2492.4	5332.9	..
1950-51							1189.3	918.0	853.4	873.7	1151.4	2783.7	6217.3	..
1951-52							2184.6	1809.0	1682.0	1645.1	1844.0	3506.5	6577.7	..
1952-53							2948.6	2616.9	2513.1	2507.5	2627.9	3886.2	6496.7	..
1953-54							122.1	0.0	0.0	0.0	0.0	1746.1	5264.6	..
1954-55							2205.1	1942.1	1878.7	1903.9	2041.7	3326.2	5740.2	..
1955-56							875.9	570.1	455.8	438.9	655.2	2533.9	6008.1	..
1956-57							1288.4	964.7	886.2	899.4	1117.1	2744.8	6817.0	..
1957-58							945.9	653.7	591.1	617.3	853.4	2492.1	6235.9	..
LIMITING RULE CURVE (hm^3)							893.0	570.5	72.9	0.0				

**Not include Limiting Rule Curve. Prior AOPs the Variable Refill Curves included the Limiting Rule Curve.

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVES														
	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	226.53	424.75	707.92	707.92	707.92	707.92
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
98.68 km^3 --							84.95	226.53	226.53	424.75	424.75	566.34	594.65	594.65
117.18 km^3 --							84.95	84.95	84.95	84.95	141.58	141.58	424.75	538.02
135.69 km^3 --							84.95	84.95	84.95	84.95	84.95	84.95	424.75	538.02

TABLE 5M
(Metric Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2002 - 03 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	0.0	0.0	993.8	2204.6	3075.9	3858.8	6067.6	5945.7	5372.0	4675.5	4612.6	6132.4	8294.5	8757.8
VARIABLE REFILL CURVES (hm^3)**														
1928-29							8541.3	7301.4	6569.6	6367.0	6847.5	7889.3	8601.0	8757.8
1929-30							4557.8	4069.7	3698.0	3579.4	3979.9	6423.3	8159.7	"
1930-31							5701.1	4469.4	3955.2	3859.8	4258.6	6025.5	8118.3	"
1931-32							1298.9	1126.2	1236.8	1669.3	2171.1	4260.5	7229.5	"
1932-33							2944.5	2882.3	2906.6	2898.0	3119.7	4676.9	7092.9	"
1933-34							0.0	30.8	566.4	1034.2	2023.6	5677.3	8226.0	"
1934-35							3479.3	3287.7	3309.0	3290.2	3503.5	5175.3	7359.4	"
1935-36							3600.2	3140.5	2749.5	2583.9	2725.8	5106.8	8140.6	"
1936-37							8757.8	7954.9	7220.4	6922.7	7440.6	8338.3	8757.8	"
1937-38							4417.8	4289.4	4236.3	4304.3	4528.2	5842.2	7825.9	"
1938-39							5045.9	4262.7	3741.1	3582.8	3976.5	6230.5	8757.8	"
1939-40							4230.9	3719.6	3332.8	3452.4	3933.2	5950.1	8280.3	"
1940-41							7248.8	6113.6	5544.0	5680.3	6894.0	8566.5	8757.8	"
1941-42							6329.1	6030.9	5799.9	5664.6	5925.9	7362.3	8677.6	"
1942-43							7357.4	7080.2	6931.0	6850.0	6955.7	8624.0	8757.8	"
1943-44							8757.8	8757.8	8643.3	8368.4	8757.8	8757.8	8757.8	"
1944-45							8750.0	7684.3	7161.2	7054.0	7530.6	8402.4	8757.8	"
1945-46							2304.2	2037.0	2329.9	2402.8	2877.4	4666.4	7601.1	"
1946-47							3798.6	3544.6	3720.8	3754.6	4058.9	5615.2	7810.8	"
1947-48							3155.1	2944.5	3271.1	3251.3	3416.9	4860.9	7605.5	"
1948-49							5027.3	4802.4	4754.2	4710.2	5762.7	7878.3	8757.8	"
1949-50							3496.7	3275.8	3246.4	3269.4	3430.4	4715.8	6803.3	"
1950-51							4202.5	4099.3	4087.3	4029.1	4283.8	5544.2	8002.6	"
1951-52							4321.7	4109.6	4059.4	4016.8	4144.3	5678.6	8258.0	"
1952-53							5225.7	5025.1	4962.7	4908.1	4994.5	6197.5	8127.8	"
1953-54							1555.5	1435.7	1939.2	2083.0	2451.0	3954.9	6774.1	"
1954-55							3505.2	3445.8	3449.5	3312.2	3574.7	4858.9	6727.7	"
1955-56							2871.3	2727.7	2676.6	2687.1	2911.2	4817.8	7600.9	"
1956-57							3016.4	2812.1	2739.5	2722.3	2959.9	4433.0	8494.6	"
1957-58							2521.5	2344.3	2381.8	2531.5	2921.7	4501.7	7662.3	"
LIMITING RULE CURVE (hm^3)							826.2	484.7	63.4	0.0				

**Not include Limiting Rule Curve. Prior AOPs the Variable Refill Curves included the Limiting Rule Curve.

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVES														
	141.58	141.58	141.58	141.58	141.58	141.58	141.58	226.53	566.34	1132.67	1132.67	1274.26	1415.84	1444.16
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
98.68 km^3 --							141.58	424.75	424.75	566.34	622.97	792.87	1217.62	1274.26
117.18 km^3 --							141.58	141.58	141.58	226.53	368.12	651.29	1217.62	1274.26
135.69 km^3 --							141.58	141.58	141.58	141.58	368.12	651.29	1217.62	1274.26

TABLE 6M
(Metric Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2002 - 03 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	196.5	369.9	532.1	607.2	650.1	677.5	702.4	697.5	625.8	606.8	587.7	866.1	1323.4	1726.8
VARIABLE REFILL CURVES (hm^3)**														
1928-29							1055.0	1045.2	1037.8	1034.4	1056.2	1219.6	1516.9	1726.8
1929-30							1051.1	1040.3	1032.2	1028.1	1084.6	1269.8	1545.0	"
1930-31							915.3	907.7	908.4	916.5	952.2	1146.2	1516.9	"
1931-32							148.0	143.6	162.2	182.3	284.1	682.1	1286.4	"
1932-33							0.0	0.0	0.0	0.0	0.0	252.2	956.9	"
1933-34							114.3	151.7	183.5	218.2	390.2	827.7	1428.6	"
1934-35							397.1	408.1	434.5	441.9	486.1	805.4	1285.7	"
1935-36							284.8	282.6	284.1	286.0	335.4	740.8	1370.8	"
1936-37							927.5	917.5	914.5	910.4	932.2	1127.9	1473.1	"
1937-38							319.3	332.7	346.2	363.8	437.0	817.2	1346.6	"
1938-39							552.9	559.0	565.2	570.5	625.4	932.9	1474.8	"
1939-40							512.1	531.4	555.6	584.5	643.2	938.0	1446.7	"
1940-41							712.9	724.4	738.4	770.4	850.9	1124.9	1504.9	"
1941-42							659.1	676.2	690.9	701.2	752.3	1036.9	1446.4	"
1942-43							628.5	630.2	639.1	643.9	721.0	1085.8	1427.3	"
1943-44							1094.6	1097.8	1102.4	1103.9	1131.1	1299.6	1590.8	"
1944-45							897.2	901.8	908.4	909.9	932.4	1126.2	1486.6	"
1945-46							6.6	0.7	9.1	14.7	95.7	551.0	1270.3	"
1946-47							108.6	104.0	116.5	128.0	213.6	655.2	1301.3	"
1947-48							203.3	210.2	225.3	228.8	294.1	696.5	1326.8	"
1948-49							786.6	780.5	780.5	778.8	830.9	1117.9	1576.6	"
1949-50							280.9	277.7	284.5	284.3	344.2	717.6	1189.8	"
1950-51							82.0	97.6	120.9	122.3	206.5	634.6	1265.9	"
1951-52							353.0	353.3	368.0	371.4	437.0	840.2	1376.5	"
1952-53							362.8	364.3	376.8	381.7	440.1	787.6	1293.8	"
1953-54							0.0	0.0	0.0	0.0	22.0	458.2	1123.7	"
1954-55							235.6	241.5	254.0	262.3	317.1	665.7	1133.0	"
1955-56							0.0	0.0	0.0	3.9	81.0	570.8	1260.2	"
1956-57							233.2	224.1	229.7	234.9	308.5	700.0	1417.8	"
1957-58							20.8	19.8	36.2	47.5	123.8	548.3	1299.9	"
LIMITING RULE CURVE (hm^3)							140.7	53.3	8.6	0.0				

**Not include Limiting Rule Curve. Prior AOPs the Variable Refill Curves included the Limiting Rule Curve.

	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	14.16	42.48	42.48	42.48	42.48	50.97	56.63
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
98.68 km^3 --							2.83	2.83	2.83	2.83	22.65	28.32	79.29	90.61
117.18 km^3 --							2.83	2.83	2.83	2.83	8.50	14.16	79.29	84.95
135.69 km^3 --							2.83	2.83	2.83	2.83	2.83	2.83	79.29	84.95

TABLE 7M
(Metric Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2002 - 03 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)
2002 - 03 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	5461.5	..
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)
2002 - 03 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)
2002 - 03 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.2	19110.6	19095.7	18042.2	16842.4	14217.4	11625.0	11470.4	10462.4	9368.0	8633.3	10663.8	15865.0	19119.2
1929-30	..	..	..	..	..	..	10115.2	8905.4	7963.4	7443.0	7767.0	10663.8	15656.0	"
1930-31	..	..	..	..	..	..	11258.5	9962.1	8866.2	8316.0	8279.3	10556.8	15688.8	"
1931-32	..	..	..	..	..	..	2441.5	1925.0	1938.0	2398.9	3266.9	7491.5	14428.8	"
1932-33	..	..	..	..	..	..	3978.2	3506.2	2885.3	2877.9	3120.4	6860.0	13563.0	"
1933-34	..	..	..	..	..	..	1859.9	1206.9	799.5	1194.4	2334.3	8186.8	15680.7	"
1934-35	..	..	..	..	..	..	6710.3	5850.1	4839.9	4719.0	4718.5	7710.9	14317.7	"
1935-36	..	..	..	..	..	..	6507.5	5452.7	4524.5	4441.1	4681.3	8800.4	15711.1	"
1936-37	..	..	..	..	..	..	11625.0	11417.8	10462.4	9368.0	8633.3	10663.8	15865.0	"
1937-38	..	..	..	..	..	..	6401.0	5824.9	3968.9	4195.2	4893.4	8175.3	15161.1	"
1938-39	..	..	..	..	..	..	10453.8	8972.7	7975.4	7485.4	7733.9	10663.8	15865.0	"
1939-40	..	..	..	..	..	..	9231.8	7856.8	7036.4	6797.4	7212.6	10231.9	15850.8	"
1940-41	..	..	..	..	..	..	11625.0	11267.3	10331.0	9280.4	8606.6	10639.8	15824.9	"
1941-42	..	..	..	..	..	..	10527.2	8278.8	6285.6	6255.5	6487.4	9263.1	15865.0	"
1942-43	..	..	..	..	..	..	9563.3	7445.0	5593.2	5873.3	6832.9	7896.6	13415.7	"
1943-44	..	..	..	..	..	..	11625.0	11470.4	10462.4	9368.0	8633.3	10663.8	15865.0	"
1944-45	..	..	..	..	..	..	11625.0	10736.4	9116.3	8784.5	8287.9	10326.9	15760.5	"
1945-46	..	..	..	..	..	..	3337.9	2660.9	2411.9	2417.5	2973.1	7022.2	14770.6	"
1946-47	..	..	..	..	..	..	4832.3	4219.2	2838.1	3042.1	4085.6	8360.8	15183.8	"
1947-48	..	..	..	..	..	..	4251.5	3675.3	2700.1	2696.4	3180.3	7508.9	14723.4	"
1948-49	..	..	..	..	..	..	10361.4	9100.6	7207.9	7493.0	7387.3	10634.4	15865.0	"
1949-50	..	..	..	..	..	..	4988.4	4258.8	3307.1	3283.8	3490.6	5667.3	11984.2	"
1950-51	..	..	..	..	..	..	5532.5	5114.9	3441.1	3462.9	3778.5	6734.8	15485.8	"
1951-52	..	..	..	..	..	..	6859.3	6078.8	4309.2	4423.2	5300.1	8118.3	14244.8	"
1952-53	..	..	..	..	..	..	8537.2	6985.8	5140.3	5270.0	5704.7	7851.1	14899.8	"
1953-54	..	..	..	..	..	..	2589.2	2059.5	2020.6	2083.0	2473.0	6159.3	11032.0	"
1954-55	..	..	..	..	..	..	5946.0	5548.2	4505.9	4710.4	4907.9	7750.1	13600.9	"
1955-56	..	..	..	..	..	..	3905.0	3351.6	2931.3	2909.7	3647.4	7922.6	14592.0	"
1956-57	..	..	..	..	..	..	4538.0	3937.1	3513.3	3718.6	4297.0	7877.8	15865.0	"
1957-58	..	..	..	..	..	..	3608.0	3051.4	3009.1	3196.2	3890.8	7542.1	15198.0	"

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

	1998-99	1999-00	2000-01	2001-02	2002-03
MICA TARGET OPERATION					
(hm^3 [xxxx.x] or m^3/s [xxxx.xx])					
AUG 15	8455.9	8455.9	8529.3	8529.3	8529.3
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	311.48	8387.4	8284.7	8309.1	8309.1
NOV	7966.6	7770.9	7477.3	566.34	566.34
DEC	6547.6	679.60	707.92	622.97	622.97
JAN	679.60	707.92	736.24	679.60	679.60
FEB	622.97	622.97	651.29	594.65	594.65
MAR	622.97	594.65	622.97	622.97	509.70
APR 15	210.9	382.2	736.2	798.1	688.2
APR 30	137.5	259.8	259.8	137.5	424.75
MAY	283.17	283.17	226.5	283.17	283.17
JUN	283.17	283.17	226.5	283.17	283.17
JUL	8333.6	8455.9	8455.9	8455.9	8455.9
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (hm^3)					
1928 AUG 31	19119.2	19119.2	19119.2	19098.6	19110.6
1928 DEC	15293.5	13746.0	13218.2	12992.4	14217.4
1929 APR15	4101.2	4313.6	3909.4	3568.9	3553.9
1929 JUL	17140.4	16920.7	17410.3	18234.5	18170.4
COMPOSITE CANADIAN TREATY STORAGE CONTENT (hm^3)					
50-yr Average for AOP99~AOP02, 60-yr average for AOP03					
AUG 31	17918.4	17848.9	18079.9	18134.9	18140.6
DEC	13662.5	12925.6	12619.1	12812.6	12788.1
APR15	2174.0	3484.0	2815.3	2777.6	2870.1
JUL	17397.0	17369.1	17795.8	18002.6	17955.6
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-5.1	-1.5	-0.3	0.2	-0.3
U.S. Dependable Peaking Capacity	27.0	0.0	-2.0	0.0	-18.0
U.S. Average Annual Usable Secondary Energy	18.9	19.5	16.2	24.9	3.7
BCH Firm Energy	26.7	102.2	60.8	48.3	30.3
BCH Dependable Peaking Capacity	18.0	-3.0	-36.0	25.0	26.0
BCH Average Annual Usable Secondary Energy	-18.5	-42.9	-43.6	-29.7	-17.3
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	10083	9793	10043	10422	10368
AUG 31	10203	9925	10125	10439	10355
SEP	9957	9630	10095	10434	9911
OCT	9963	9764	10046	10388	10051
NOV	11305	11297	11381	11626	11716
DEC	12787	12766	12836	13012	13160
JAN	13640	13725	13484	13382	13707
FEB	12638	12674	12765	12502	12694
MAR	11994	12113	11807	11667	11858
APR 15	11671	11099	11332	11187	11460
APR 30	12425	12672	13025	12575	13101
MAY	15701	17263	14347	14647	14357
JUN	14662	14699	11925	12590	13324
JUL	10594	9894	11275	10493	10457
ANNUAL AVERAGE	12117	12131	11850	11919	11986

Appendix A1
(English Units)
Project Operating Procedures
2002-03 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 Linn	Corra	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	2883.0 ft	Conditions permitting, should be on or about, empty Mar and Apr 15		FERC, AOP80
Thompson Falls (1490)				None Noted		

Appendix A1
(English Units)
Project Operating Procedures
2002-03 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
Noxon Rapids (1480)	Minimum Content For Step I:	116.3 ksfd	2331.0 ft	May - Aug 31,	In place in AOP84, similar operation in AOP80
		112.3 ksfd	2330.0 ft	Sep - Jan,	
		78.7 ksfd	2321.0 ft	Feb,	
		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 Steps 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, AOP84
		465.7 ksfd	2060.0 ft	Sep	
		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 Steps I & II:	Optimum to run CP & LT to Jun-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).			
		57.6 ksfd	2051.0 ft	Nov - Mar	
		458.4 ksfd	2059.8 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	
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	1240.0 ft	May and June	Retain as a power operation (for pumping)
		0.0 ksfd	1208.0 ft	Empty at end of CP	
	Steps II & III only	2557.1 ksfd	1288.0 ft	Aug-Nov	
	Maximum Content Step I only:		2 ft	Operating room Sep - Nov	In place in AOP89. Retain as a power operation
			3 ft	Operating room Dec - Feb	
	Draft Limit		1.3 ft/day	(bank sloughage)	
			1.5 ft/day	(Constraint submitted as 1.5 ft/day interpreted as 1.3 ft/day mo.ave.)	

Appendix A1
(English Units)
Project Operating Procedures
2002-03 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
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	
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 submittal 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
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	

Appendix A1
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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
	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 Step I:	269.7 ksfd 242.5 ksfd 153.7 ksfd 114.9 ksfd	268.0 ft 267.0 ft 263.6 ft 262.0 ft	June - Aug 15 Aug 31 - Sep Oct - Mar Apr 15 - May	In place AOP80
	Steps II & III:	190.0 ksfd	265.0 ft	Use JDA as run-of-river plant.	
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

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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
Couer d'Alene L (1341)	Minimum Flow	50 cfs		All periods	
	Minimum Content	112.5 ksfd	2128.0 ft	May - Aug	In place in AOP79
Post Falls (1340)	Minimum Flow	50 cfs		All periods	In place in AOP79, AOP80, AOP84
Other Major Step I Projects					
Libby (1760) without sturgeon					
	Minimum Flow	4000 cfs		All periods	
	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		5 ft		
	Other			Operate to meet IJC orders for Corra Linn	CRTOC agreement on procedures to implement 1938 IJC order

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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	1300 cfs		All periods	2-1-97 PNCA submittal
	Maximum Flow	14000 cfs		All periods	2-1-97 PNCA submittal
		25000 cfs		Up to 25 kcfs for flood control	
	Minimum Elev	395.8 ksfd	1520.0 ft	SMIN Apr - Aug 31	
	Start 3 yr CP at	395.1 ksfd	1519.9 ft	Aug 15 (0.3 ft) higher than AOP02	
	End 3 yr CP at:	218.4 ksfd	1490.2 ft	Feb (19.5 ft) lower than AOP02.	
	Other	Run on minimum flow or flood control observing maximum & minimum flow requirements all periods except to meet LWG outflows:			2-1-97 PNCA submittal
	LWG Target Flow	85000 cfs to 50000 cfs to	100000 cfs 55000 cfs	Apr 10 - Jun 20, and Jun 21 - Aug 31.	
	Other Spill	100 cfs		All periods	
Lower Granite (520)	Bypass Date			None	
	Other Spill	670 cfs		All periods	
	Incremental Spill			Removed	
	Fish Spill	(LT only if regulated flow ≥ 100000 cfs)			
			16.0%	Apr 15	2-1-97 PNCA submittal
			40.0%	Apr 30 & May	
			26.7%	Jun	
		(CP only if regulated flow ≥100000 cfs)			
			20.1%	Apr 15	
			39.7%	Apr 30	
			27.0%	May	
			24.0%	Jun	
	Maximum Fish Spill	22500 cfs			
	Minimum Flow	11500 cfs		Mar-Nov	
	Other	224.9 ksfd 245.8 ksfd	733 ft 738 ft	Run at (MOP) Apr 15 - Oct. Run at all other periods.	

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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
Little Goose (518)	Bypass Date			None	
	Other Spill	630 cfs		All periods	
	Incremental Spill			Removed	
	Fish Spill	(LT only if regulated flow at Lower Granite ≥ 85000 cfs)			2-1-97 PNCA submittal
			16.0%	Apr 15	
			40.0%	Apr 30 & May	
			26.7%	Jun	
		(CP only if regulated flow at Lower Granite ≥ 85000 cfs)			
			20.2%	Apr 15	
			40.3%	Apr 30	
			29.9%	May	
			26.4%	Jun	
	Maximum Fish Spill	25000 cfs			
	Minimum Flow	11500 cfs		Mar - Nov	
	Other	260.5 ksfd	633.0 ft	On MOP Apr 15 - Aug 31.	
		285.0 ksfd	638.0 ft	On full pool Sep 30 - Mar 31.	
Lower Monumental (504)	Bypass Date			A bypass date of 2010 was assumed.	
	Other Spill	750 cfs		All periods	
	Fish Spill	(LT only if regulated flow at Lower Granite ≥ 85000 cfs)			2-1-97 PNCA submittal
			16.2%	Apr 15	
			40.5%	Apr 30 & May	
			27.0%	Jun	
		(CP only if regulated flow at Lower Granite ≥ 85000 cfs)			
			20.5%	Apr 15	
			36.2%	Apr 30	
			24.0%	May	
			21.1%	Jun	
	Maximum Fish Spill	20000 cfs			
	Minimum Flow	11500 cfs		Mar-Nov	
	Other	180.5 ksfd	537.0 ft	On MOP Apr 15 - Aug 31.	
		190.1 ksfd	540.0 ft	On full pool Sep 30 - Mar 31.	
Cushman (2206)	Other Spill	100 cfs		All periods	
White River (2160)	Other Spill	130 cfs		All periods	
Round Butte (390)	Other Spill	200 cfs		All periods	

Appendix A2
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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
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	42.48 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
	Other	0.0 hm^3	878.74 m	Conditions permitting, should be on or about, empty Mar and Apr 15	FERC, AOP80
Thompson Falls (1490)				None Noted	

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Project Name (Number)	Constraint Type	Requirements			Source
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 Steps 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 Steps I & II:	Optimum to run CP & LT to Jun-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).			
		140.9 hm^3	625.14 m	Nov - Mar	
		1121.5 hm^3	627.83 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	
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	377.95 m	May and June	Retain as a power operation (for pumping)
		0.0 hm^3	368.20 m	Empty at end of CP	
	Steps II & III only	6256.2 hm^3	392.58 m	Aug-Nov	
	Maximum Content Step I only:		0.61 m	Operating room Sep - Nov	In place in AOP89. Retain as a power operation
			0.91 m	Operating room Dec - Feb	
	Draft Limit		0.40 m/day	(bank sloughage)	
			0.46 m/day	(Constraint submitted as 0.46 m/day interpreted as 0.40 m/day mo. ave.)	

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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
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	
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	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	

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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
John Day (440)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	22.65 m³/s		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
	Minimum Flow	1415.84 m³/s 353.96 m³/s		Mar - Nov Dec - Feb	
	Step I:	659.8 hm³ 593.3 hm³ 376.0 hm³ 281.1 hm³	81.69 m 81.38 m 80.35 m 79.86 m	June - Aug 15 Aug 31 - Sep Oct - Mar Apr 15 - May	In place AOP80
		464.9 hm³	80.77 m	Use JDA as 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 m³/s		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
	Minimum Flow	1415.84 m³/s 353.96 m³/s		Mar - Nov Dec - Feb	
Bonneville (320)	Fish Bypass			Bypass not modeled (installation date set to year 2010 in input file).	
	Other Spill	227.67 m³/s		All periods	
	Incremental Spill			None	
	Fish Spill			Removed	
Kootenay Lake (Corra Linn (1665))	Minimum Flow	141.58 m³/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 m³/s		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	754.8 hm³	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 m³/s		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	275.2 hm³	648.61 m	May - Aug	In place in AOP79
Post Falls (1340)	Minimum Flow	1.42 m³/s		All periods	In place in AOP79, AOP80, AOP84
Other Major Step I Projects					
Libby (1760) without sturgeon					
	Minimum Flow	113.27 m³/s		All periods	
	Other Spill	5.66 m³/s		All periods	

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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
	Minimum Content	By contract year: Aug-Jul i.e., 1929 = Aug 1928 - Jul 1929			
		1900.76 hm^3	720.24 m	1929 Dec	2-1-93 PNCA submittal, in place in AOP99 (w/o sturgeon)
		1655.12 hm^3	717.80 m	1929 Jan	
		1476.77 hm^3	715.98 m	1929 Feb	
		5254.56 hm^3	744.63 m	1929 Jul	
		1595.18 hm^3	717.19 m	1930 Dec	
		1059.87 hm^3	711.40 m	1930 Jan	
		952.46 hm^3	710.18 m	1930 Feb	
		852.64 hm^3	708.96 m	1930 Mar	
		727.62 hm^3	707.44 m	1930 Apr 15	
		1086.78 hm^3	711.71 m	1930 Apr 30	
		1221.10 hm^3	713.23 m	1930 May	
		3289.70 hm^3	732.13 m	1930 Jun	
		4335.13 hm^3	739.14 m	1930 Jul	
		777.53 hm^3	708.05 m	1931 Dec	
		470.24 hm^3	704.09 m	1931 Jan	
		252.24 hm^3	701.04 m	1931 Feb-Apr 30	
		470.24 hm^3	704.09 m	1931 May	
		1655.12 hm^3	717.80 m	1931 Jun	
		2123.65 hm^3	722.38 m	1931 Jul	
		426.69 hm^3	703.48 m	1932 Dec	
		252.24 hm^3	701.04 m	1932 Jan	
		0.00 hm^3	697.08 m	Empty at end of CP***	
		1900.76 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		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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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	36.81 m^3/s		All periods	2-1-97 PNCA submittal
	Maximum Flow	396.44 m^3/s		All periods	2-1-97 PNCA submittal
		707.92 m^3/s		Up to 707.92 m^3/s for flood control	
	Minimum Elev	968.36 hm^3	463.30 m	SMIN Apr - Aug 31	
	Start 3 yr CP at End 3 yr CP at:	966.65 hm^3 534.34 hm^3	463.27 m 454.21 m	Aug 15 (0.09 m) higher than AOP02 Feb (5.94 m) lower than	
	Other	Run on minimum flow or flood control observing maximum & minimum flow requirements all periods except to meet LWG outflows:			2-1-97 PNCA submittal
	LWG Target Flow	2406.93 m^3/s to 1415.84 m^3/s to	2831.68 m^3/s 1557.43 m^3/s	Apr 10 - Jun 20, and Jun 21 - Aug 31.	
	Other Spill	2.83 m^3/s		All periods	
Lower Granite (520)	Bypass Date			None	
	Other Spill	18.97 m^3/s		All periods	
	Incremental Spill			Removed	
	Fish Spill	(Only if regulated flow is $\geq$ 2831.66 m^3/s)	16.0% 40.0% 26.7%	Apr 15 Apr 30 & May Jun	2-1-97 PNCA submittal
		(CP only if regulated flow is $\geq$ 2831.66 m^3/s)	20.1% 39.7% 27.0% 24.0%	Apr 15 Apr 30 May Jun	
	Maximum Fish Spill	637.13 m^3/s			
	Minimum Flow	325.64 m^3/s		Mar-Nov	
	Other	550.24 hm^3 601.37 hm^3	223.42 m 224.94 m	Run at (MOP) Apr 15 - Oct. Run at all other periods.	

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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
Little Goose (518)	Bypass Date			None	
	Other Spill	17.84 m^3/s		All periods	
	Incremental Spill			Removed	
	Fish Spill	(Only if regulated flow at Lower Granite is ≥ 2406.91 m^3/s)			2-1-97 PNCA submittal
			16.0%	Apr 15	
			40.0%	Apr 30 & May	
			26.7%	Jun	
		(CP only if flows ≥ 2406.91 m^3/s)			
			20.2%	Apr 15	
			40.3%	Apr 30	
			29.9%	May	
			26.4%	Jun	
	Maximum Fish Spill	707.92 m^3/s			
	Minimum Flow	325.64 m^3/s		Mar - Nov	
	Other	637.34 hm^3	192.94 m	On MOP Apr 15 - Aug 31.	
		697.28 hm^3	194.46 m	On full pool Sep 30 - Mar 31.	
Lower Monumental (504)	Bypass Date			A bypass date of 2010 was	
	Other Spill	21.24 m^3/s		All periods	
	Fish Spill	(Only if regulated flow at Lower Granite is ≥ 2406.91 m^3/s)			2-1-97 PNCA submittal
			16.2%	Apr 15	
			40.5%	Apr 30 & May	
			27.0%	Jun	
		(CP only if flows > 2406.91 m^3/s)			
			20.5%	Apr 15	
			36.2%	Apr 30	
			24.0%	May	
			21.1%	Jun	
	Maximum Fish Spill	566.34 m^3/s			
	Minimum Flow	325.64 m^3/s		Mar-Nov	
	Other	441.6 hm^3	163.68 m	On MOP Apr 15 - Aug 31.	
		465.1 hm^3	164.59 m	On full pool Sep 30 - Mar 31.	
Cushman (2206)	Other Spill	2.83 m^3/s		All periods	
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 2002-03

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DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB) FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2002-03

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 2002-03 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.

As part of the DDPB for the operating year 2002-03, separate determinations were carried out relating to the limit of year-to-year change in benefits attributable to the

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

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	=	1170.7 MW
Average Annual Usable Energy	=	534.5 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 2002-03 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 2001-02 Step II Joint Optimum study and the 2001-02 Step III study.

Y = One-half of the downstream power benefits derived from the difference between the 2001-02 Step II U.S. Optimum study and the 2001-02 Step III study.

Z = One-half of the downstream power benefits derived from the difference between the 2002-03 Step II U.S. Optimum study with 15 Maf (18.50 km^3) of Canadian storage and the 2002-03 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 2001-02 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	= 1427.1 - (1427.1 - 1146.4) = 1146.4 MW
Average Annual Usable Energy	= 532.6 - (532.2 - 527.6) = 528.0 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 expired 31 March 1998 for Duncan, 31 March 1999 for Arrow, and expires 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 2002-03 AOP for this condition was:

Dependable Capacity	= 1171.4 MW
Average Annual Usable Energy	= 532.8 aMW

Because the 2002-03 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 increase in the Energy Entitlement of 1.7 aMW and a decrease in the Capacity Entitlement of 0.7 MW.

Since the sale of the downstream power benefits attributable to Duncan and Arrow expired 31 March 1998 and 31 March 1999 respectively, the United States Entity is entitled to that portion of the decrease in the Canadian Entitlement attributed to Mica from 1 April 2002 through 31 March 2003, and none thereafter. Because there was no decrease in the Energy Entitlement, but there was a decrease in the Capacity Entitlement, the United States Entity is entitled to receive compensation for the decrease in dependable capacity attributed to the re-operation of Mica. The decrease of the Canadian Entitlement attributed to Mica is computed by multiplying the decrease in the Canadian Entitlement by the ratio of Mica storage (7.0 Maf (8.63 km^3))

to the whole of the Canadian storage (15.5 Maf (19.12 km^3)). The value is computed to be:

Capacity Payment = 0.7 MW (7.0 Maf/15.5 Maf) = 0.3 MW
= 0.7 MW (8.63 km^3/19.12 km^3) = 0.3 MW

Energy Payment = Not applicable

Accordingly, the Entities agreed that the United States Entity is not entitled to receive any energy but is entitled to receive 0.3 MW dependable capacity during the period 1 April 2002 through 31 March 2003, 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, Arrow storage, and Mica storage terminated on 31 March 1998, 31 March 1999, and terminates 31 March 2003, 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), in Mica is 7.0 Maf (8.63 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 2002-03 beginning 1 August 2002 and ending 31 March 2003, based on the Joint Optimum power studies for benefits attributable to Duncan and Arrow is computed below.

Energy Entitlement Returned
Average Annual Usable Energy =
534.5 aMW * (8.5 Maf/15.5 Maf) = 293.1 aMW
534.5 aMW * (10.48 km^3/19.12 km^3) = 293.1 aMW

Capacity Entitlement Returned
Dependable Capacity =
1170.7 MW * (8.5 Maf/15.5 Maf) = 642.0 MW
1170.7 MW * (10.48 km^3/19.12 km^3) = 642.0 MW

The obligation of the United States to deliver the Canadian Entitlement to Canada beginning 1 April 2003 and ending 31 July 2003 is based on the Joint Optimum power studies for benefits attributable to Duncan, Arrow, and Mica is:

Energy Entitlement Returned
Average Annual Usable Energy = 534.5 aMW

Capacity Entitlement Returned
Dependable Capacity = 1170.7 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 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. The format is different from the previous year due to changes in the interpretation of the definition and use of thermal installations (see Summary of Changes from Previous Year, paragraph 7a).

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). The format is different from the previous year due to changes in the interpretation of the definition and use of thermal installations (see Summary of Changes from Previous Year, paragraph 7a).

Table 3. Determination of Loads for 2002-03 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 were based on the final BPA 31 December 1996 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 2002-03 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. The hydro maintenance is no longer included in the Step 1 system load, but instead summed with the reserves as an adjustment to resources.

Table 5. Computation of Canadian Entitlement For 2002-03 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 are summarized in Table 6. An explanation of the more important changes compared to last year's studies follows.

(a) Loads and Non-Hydro Resources

Loads for the 2002-03 AOP were based on the final 1996 Whitebook medium case forecast developed by BPA on 31 December 1996. Compared to the previous AOP, the PNWA firm energy load increased by 128 aMW. Other load changes include:

- It was assumed that one-half of the Entitlement was exported to B.C., one-eighth was exported to the Southwest (SW), and three-eighths was used to meet load in the PNWA. This was a decrease of 43 aMW in the Canadian Entitlement exports compared to the 2001-02 AOP study, which modeled all of the Entitlement exported to Canada, and one-half of the Entitlement imported into the Region.

- There were new exports to BART, SCE, M-S-R, Turlock Irrigation District share of Boardman, and New Energy Venture.

- Exports to SCE Power, Utah, and WAPA were terminated.
- The average annual firm surplus increased by only 10 aMW and was again shaped into May and June (1937 aMW in May and June for 2002-03 and 1877 aMW in May and June in 2001-02 AOP study).

There was a clarification and modification of the thermal installations for this study (see Table 1A and Table 2 of DDPB document). The total annual energy capability of the thermal installations increased by 576 aMW due to the following changes:

- Large Thermal resources increased by 235 aMW (127 aMW from WNP2, 56 aMW from Centralia, 69 aMW from Colstrip 4, and 17 aMW less from Boardman Coal);
- Cogeneration decreased by 11 aMW;
- Thermal PURPA/NUGS decreased by 27 aMW;
- Increased Plant Sales reduce the Thermal Installation by 39 aMW; and
- Thermal Imports increased by 416 aMW mostly due to an increase in the Thermal Import from Pacificorp; and the shaping of the thermal imports to estimated total capability. All of the SW imports were not included as Thermal Installations this year since a specific thermal project was not identified.

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 are show below for the Joint Optimum studies. The Entitlement Return which was assumed to be imported to load in the PNWA is also shown in the table:

During 1 August 2002 – 31 March 2003

	Energy Entitlement Returned (aMW)		**Capacity Returned (MW)**	
	Estimated	Computed	Estimated	Computed
Export to B.C.	146.1		391.3	
Import to PNW	109.5		293.5	
Export to SW	36.5		97.8	
Total	292.1	293.1	782.6	642.0

During 1 April 2003 – 31 July 2003

	Energy Entitlement Returned (aMW)		**Capacity Returned (MW)**	
	Estimated	Computed	Estimated	Computed
Export to B.C.	266.3		713.5	
Import to PNW	199.7		535.2	
Export to SW	66.6		178.4	
Total	532.6	534.5	1427.1	1170.7

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.

(b) Operating Procedures

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. Minor changes from the previous studies included (see Appendix A1 (English units) or Appendix A2 (Metric units)):

- Grand Coulee pumping requirement in both May and June of 1240 ft (377.95 m) 843.9 ksfd (2064.7 hm^3) instead of May only;
- Noxon flood control rule curves were updated for all periods; and
- John Day was operated to be consistent with the 1979-80 AOPs at:
  268.0 ft (81.69 m) 269.7 ksfd (659.9 hm^3) in June–15 August;
  267.0 ft (81.38 m) 242.5 ksfd (593.3 hm^3) in 31 August–September;
  263.6 ft (80.35 m) 153.7 ksfd (376.0 hm^3) in October–March; and
  262.0 ft (79.86 m) 114.9 ksfd (281.1 hm^3) in 15 April–May.

John Day was operated to 265.0 ft (80.77 m) 190.0 ksfd (464.9 hm^3) during all periods in the 2001-02 AOP study.

(c) Step III Critical Streamflow Period

The Step III study critical streamflow period was a 6-month critical period, 1 November 1936 through 30 April 1937. The critical period started one month later due to increased thermal imports and the flood control changes at Hungry Horse; and ended 1/2 month later due to a change in the thermal maintenance schedule.

(d) Downstream Power Benefits Computation

The Capacity Entitlement decreased from 1427.1 MW in the 2001-02 DDPB to 1170.7 MW in the 2002-03 DDPB for a loss of 257.1 MW. This was due to the Step III critical period length change as noted above.

The Canadian Energy Entitlement increased from 532.6 aMW in the 2001-02 DDPB to 534.5 aMW in the 2002-03 DDPB. This slight increase of 1.9 aMW was mostly due to the change in the interpretation of thermal installations, the increase of 465 aMW in the Thermal Displacement Market, and the update of PDR's, hedges, and distributions.

TABLE 1A
2002-03 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 3/**	20456	20378	19947	20610	22536	24120	24744	23673	22350	21147	21244	20623	20478	20637	21769.7	21870.5
a) Annual Load Shape in Percent	93.96	93.61	91.63	94.67	103.52	110.80	113.66	108.74	102.66	97.14	97.58	94.73	94.07	94.80	100.0	100.5
2. **Flows-Out of firm power from PNWA**																
a) Canadian Entitlement Export (south+north) 4/	183	183	183	183	183	183	183	183	183	333	333	333	333	333	232.8	225.1
b) Exports to the East	80	80	65	43	65	65	66	44	39	42	42	28	83	85	58.7	58.9
c) SW Seasonal Exchange Exports	169	169	180	15	0	0	0	0	0	0	0	0	180	180	60.5	57.9
d) Other SW Exports	1035	1035	1031	997	942	908	692	668	620	595	631	717	822	843	824.8	834.4
e) Plant Sale Exports	142	142	142	142	142	142	142	142	142	142	137	124	142	142	140.4	140.7
f) Surplus Firm Energy Exports	0	0	0	0	0	0	0	0	0	0	0	1937	1937	0	323.7	274.1
g) Thermal Install. power used outside region 5/	442	485	420	73	179	36	137	78	342	159	101	313	536	350	255.7	244.1
h) ...Subtotal	2050	2093	2021	1453	1511	1334	1220	1115	1325	1271	1243	3452	4033	1932	1896.7	1835.2
i) Exclude Plant Sales	-142	-142	-142	-142	-142	-142	-142	-142	-142	-142	-137	-124	-142	-142	-140.4	-140.7
j) ...Total	1908	1951	1879	1311	1369	1192	1078	973	1183	1129	1107	3328	3890	1790	1756.3	1694.5
3. **Load served by Flows-In of firm power except Step I thermal installations**																
a) Non-thermal firm imports from north 6/	-20	-20	-15	-21	-36	-47	-60	-69	-61	-29	-29	-28	-38	-26	-37.3	-37.6
b) Flows-in from SW seasonal exchanges	0	0	0	0	-176	-182	-182	-182	-30	-6	-6	0	0	0	-62.4	-69.7
c) Non-Coord. Thermal Resc from SW (not TI) 7/	-16	-16	-41	-53	-73	-88	-88	-88	-27	-25	-4	0	0	-16	-41.8	-45.7
d) ...Total	-36	-36	-56	-74	-285	-317	-330	-339	-118	-60	-39	-28	-38	-42	-141.4	-153.0
4. **Load served by non-Step I resources located within the PNWA**																
a) Hydro Independents (1929 water)	-1283	-1256	-1175	-1202	-1232	-1160	-1104	-924	-1046	-1282	-1327	-1772	-1728	-1427	-1280.7	-1144.8
b) Non-Step I Coordinated Hydro (1929 water)	-510	-436	-557	-931	-944	-1040	-1087	-525	-677	-928	-835	-776	-1191	-769	-822.4	-831.3
c) Non-Thermal PURPA/NUGS	-128	-128	-119	-108	-112	-110	-110	-113	-120	-134	-134	-139	-140	-134	-122.3	-120.9
d) Miscellaneous Resources	-11	-11	-12	-10	-10	-11	-10	-10	-11	-12	-12	-13	-14	-12	-11.3	-11.2
e) ...Total (1929 water)	-1932	-1831	-1863	-2250	-2297	-2321	-2310	-1572	-1854	-2356	-2308	-2701	-3073	-2342	-2236.6	-2108.2
5. **Total Step I System Firm Loads (1929 water) 8/**	20396	20462	19905	19596	21322	22674	23182	22734	21562	19860	20003	21222	21257	20043	21148.0	21303.9
6. **Step I Thermal Installations**																
a) Large Thermal (includes plant sales)	4923	4923	4923	4923	4923	4923	4923	4923	4736	4563	3490	3105	3991	4923	4602.1	4651.2
b) Small Thermal	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32.4	32.4
c) Combustion Turbines	2079	2079	2083	2096	2098	2101	2110	2108	2105	1648	1296	1569	1801	1906	1960.4	1981.4
d) Cogeneration (includes plant sales)	1500	1500	1500	1489	1489	1489	1489	1489	1489	1500	1409	1221	1500	1500	1467.4	1471.1
e) Exclude Plant Sales	-142	-142	-142	-142	-142	-142	-142	-142	-142	-142	-137	-124	-142	-142	-140.4	-140.7
f) Thermal PURPA/NUGS	192	192	179	162	168	165	165	170	180	201	201	209	210	201	183.4	181.3
g) Thermals classified as Renewables	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54.2	54.2
h) Thermal Installation Imports from the East	1931	1931	1931	1871	1931	1931	1931	1931	1931	1478	1398	1595	1693	1931	1837.3	1850.2
i) ...Total	10569	10569	10560	10485	10553	10553	10562	10565	10385	9334	7744	7661	9139	10405	9996.8	10081.2
7. **Total Step I Hydro Load (1929 water) 9/**	9827	9893	9345	9111	10769	12121	12620	12169	11176	10525	12258	13561	12118	9638	11151.2	11222.7
a) Hydro Maintenance included as load	31	26	9	9	4	0	0	0	5	7	8	20	14	50	12.4	11.3
b) Coordinated Hydro Model Load (1929 water) 10/	10368	10355	9911	10051	11716	13160	13707	12694	11858	11460	13101	14357	13324	10457	11986.0	12065.3

1/ Step I Loads and Resources for the U.S. Optimum Study (03-11) 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/ Source is the 1996 BPA Whitebook.
4/ Includes 183 aMW August through March and 333 aMW April through July uniform export of Canadian Entitlement, 3/8 remained in region and 1/8 exported to the SW.
5/ Amount of import thermal installation capacity that is not used in the PNWA.
6/ Skagit River Treaty power from BC Hydro.
7/ Flows of Power into the region from thermal resources not identified with a specific thermal installation and not coordinated with PNWA.
8/ Line 1(a) + line 2(j) + line 3(d) + line 4(e).
9/ Hydro load for U.S. projects located upstream of Bonneville Dam (except hydro independents), line 5 minus line 6(i).
10/ The Coordinated Hydro Model Load is the Step I Hydro Load plus Hydro Maintence plus Non-Step I Coordianted Hydro.

TABLE 1B
2002-03 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 2/	25388	25343	25210	27711	29813	32294	33029	32433	30021	28419	28501	26879	25889	25421
a) Annual Load Shape in Percent	80.41	80.41	79.12	74.37	75.59	74.69	74.92	72.99	74.45	74.37	74.37	76.72	79.10	81.18
2. Flows-Out of firm power from PNWA														
a) Canadian Entitlement Export (south+north) 3/	489	489	489	489	489	489	489	489	489	892	892	892	892	892
b) Exports to the East	93	93	73	60	73	73	73	62	55	61	61	42	94	95
c) SW Seasonal Exchange Exports	390	390	390	60	0	0	0	0	0	0	0	0	390	390
d) Other SW Exports	1563	1563	1596	1543	1358	1325	1113	1113	1113	1113	1163	1338	1398	1379
e) Plant Sale Exports	167	167	167	167	167	167	167	167	167	167	167	96	167	167
f) Surplus Firm Peak Exports	0	0	0	0	0	0	0	0	0	0	0	2525	2449	0
g) Thermal install. power used outside region 4/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h) ... Subtotal	2701	2701	2715	2319	2087	2054	1842	1831	1824	2233	2283	4892	5389	2923
i) Exclude Plant Sales	-167	-167	-167	-167	-167	-167	-167	-167	-167	-167	-167	-96	-167	-167
j) ...Total	2535	2535	2548	2152	1920	1887	1675	1664	1657	2066	2116	4797	5222	2756
3. Load served by Flows-In of firm power except Step I thermal Installations														
a) Non-thermal firm imports from north 5/	-147	-147	-147	-147	-134	-148	-170	-194	-224	-147	-147	-147	-147	-147
b) Flows-in from SW seasonal exchanges	0	0	0	0	-376	-376	-376	-376	-46	-12	-12	0	0	0
c) Non-Coord. Thermal Resc from SW (not TI) 6/	0	0	0	-422	-429	-429	-429	-429	0	0	0	0	0	0
d) ...Total	-147	-147	-147	-569	-939	-953	-975	-999	-270	-159	-159	-147	-147	-147
4. Load served by non-Step I resources located within the PNWA														
a) Hydro Independents (1937 water)	-2052	-2029	-1938	-1788	-1634	-1595	-1550	-1664	-1787	-1996	-2003	-2170	-2209	-2117
b) Non-Step I Coordinated Hydro (1937 water)	-2437	-2392	-2448	-2380	-2269	-2183	-2071	-1943	-1908	-1897	-1889	-1954	-2178	-2233
c) Non-Thermal PURPA/NUGS	-135	-135	-129	-120	-120	-117	-116	-118	-123	-134	-134	-142	-144	-140
d) Miscellaneous Resources	-11	-11	-12	-10	-310	-311	-310	-310	-311	-12	-12	-13	-14	-12
e) ..Total (1937)	-4635	-4567	-4527	-4298	-4333	-4206	-4046	-4036	-4129	-4039	-4038	-4279	-4545	-4502
5 Total Step I System Firm Loads (1937water) 7/	23142	23164	23084	24997	26461	29022	29683	29062	27279	26288	26420	27251	26420	23529
6. Step I Thermal Installations														
a) Large Thermal (includes plant sales)	5473	5473	5473	5473	5473	5473	5473	5473	5208	4996	3985	3871	3178	5473
b) Small Thermal	38	38	38	38	41	41	41	41	38	38	38	38	38	38
c) Combustion Turbines	2221	2043	2163	2469	2480	2488	2500	2493	2484	2023	1584	2070	2243	2235
d) Cogeneration (includes plant sales)	1572	1572	1572	1561	1561	1561	1561	1561	1561	1572	1572	1027	1412	1572
e) Exclude Plant Sales	-167	-167	-167	-167	-167	-167	-167	-167	-167	-167	-167	-96	-167	-167
f) Thermal PURPA/NUGS	203	203	194	180	180	175	174	177	184	201	201	213	216	210
g) Thermals classified as Renewables	55	55	55	55	55	55	55	55	55	55	55	55	55	55
h) Thermal Installation Imports from the East	1656	1656	1782	1797	1903	1953	1909	1854	1687	1376	1375	1468	1316	1635
i) ...Total	11050	10872	11109	11406	11526	11578	11545	11486	11050	10094	8643	8646	8291	11050
7. Total Step I Hydro Load (1929) 8/	12091	12292	11975	13591	14935	17444	18138	17576	16230	16193	17777	18605	18129	12479
a) Hydro Maintenance included as load	4606	4043	3787	3208	2935	2037	1561	2289	2633	2751	2483	2360	2202	3721
b) Coordinated Hydro Model Load (1937) 9/	19134	18727	18210	19180	20138	21664	21770	21808	20771	20841	22148	22918	22509	18433

1/ Step I Loads and Resources for the U.S. Optimum Study (03-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements. Total regional firm load plus pumping
2/ Source is the 1996 BPA Whitebook.
3/ Includes 489 MW August through March and 892 MW April through July uniform export of Canadian Entitlement, 3/8 remained in region and 1/8 exported to the SW.
4/ Amount of import thermal installation capacity that is not used in the PNWA.
5/ Skagit River Treaty power from BC Hydro
6/ Flows of Power in to the region from thermal resources not identified with a specific thermal installation and not coordinated with PNWA.
7/ Line 1(a) + line 2(j) + line 3(d) + line 4(e).
8/ Hydro load for U.S. projects located upstream of Bonneville Dam (except hydro independents), line 5 minus line 6(i)
9/ The Coordinated Hydro Model Load is the Step I Hydro Load plus Hydro Maintence plus Non-Step I Coordanted Hydro.

TABLE 2
2002-03 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																
a) From Table 1A, line 6(i)	10569	10569	10560	10485	10553	10553	10562	10565	10385	9334	7744	7661	9139	10405	9996.8	10081.2
2. MINIMUM THERMAL GENERATION																
a) Large Thermal Min. Generation	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147.0	147.0
b) Cogen & Small Thermal Min. Gen.	431	431	431	431	431	431	431	431	431	431	431	197	431	431	411.1	414.2
c) NUGS Thermal Min. Generation	64	64	60	54	56	55	55	57	60	67	67	70	70	67	61.1	60.4
d) ...Total Minimum Generation	642	642	638	632	634	633	633	635	638	645	645	414	648	645	619.3	621.6
3. DISPLACEABLE THERMAL RESOURCES	9927	9927	9922	9854	9919	9920	9929	9930	9747	8689	7099	7248	8491	9760	9377.6	9459.6
4. SYSTEM SALES																
a) Total Flows-Out (Table 1A, Line 2(h))	2050	2093	2021	1453	1511	1334	1220	1115	1325	1271	1243	3452	4033	1932	1896.7	1835.2
b) Exclude Seasonal Exchange Exports	-169	-169	-180	-15	0	0	0	0	0	0	0	0	-180	-180	-60.5	-57.9
c) Exclude Plant Sales Exports	-142	-142	-142	-142	-142	-142	-142	-142	-142	-142	-137	-124	-142	-142	-140.4	-140.7
d) Exclude Flows-Through Transfers	-16	-16	-41	-53	-78	-93	-93	-93	-28	-25	-4	0	0	-16	-43.6	-47.7
e) Exclude Can Entitlement (out of the PNWA)	-183	-183	-183	-183	-183	-183	-183	-183	-183	-333	-333	-333	-333	-333	-232.8	-225.1
f) ...Total System Sales	1541	1584	1474	1060	1108	916	802	697	973	771	770	2995	3378	1261	1419.4	1363.8
g) Uniform Average Annual System Sales	1419	1419	1419	1419	1419	1419	1419	1419	1419	1419	1419	1419	1419	1419	1419.4	1419.4
4. THERMAL DISPLACEMENT MARKET	8508	8508	8503	8434	8500	8501	8510	8511	8328	7270	5680	5828	7072	8341	7958.2	8040.2

Notes:

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, 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 Installation Resources that are displaceable, line 1(a) minus line 2(d).
Line 4c Plant sales include Longview Fibre and approximately 22 percent of Boardman.
Line 4d Flow through transfers include Flows-in that support Flows-Out, i.e., SW imports and a 1.9 aMW exchange adjustment.
Line 4f System Sales are total exports excluding plant sales, 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, lines 3 minus line 4(g).

TABLE 3
2002-03 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	20456	93.96	25388	80.41	10569	17795.8	7226.9	15451.8	4882.8	August 1-15
August 16-31	20378	93.61	25343	80.41	10569	17728.0	7159.0	15392.9	4823.9	August 16-31
September	19947	91.63	25210	79.12	10560	17353.0	6793.0	15067.3	4507.3	September
October	20610	94.67	27711	74.37	10485	17929.6	7444.2	15568.0	5082.5	October
November	22536	103.52	29813	75.59	10553	19605.3	9051.9	17022.9	6469.6	November
December	24120	110.80	32294	74.69	10553	20983.7	10430.4	18219.8	7666.5	December
January	24744	113.66	33029	74.92	10562	21526.6	10964.8	18691.2	8129.4	January
February	23673	108.74	32433	72.99	10565	20594.4	10029.4	17881.8	7316.7	February
March	22350	102.66	30021	74.45	10385	19443.5	9058.1	16882.5	6497.0	March
April 1-15	21147	97.14	28419	74.37	9334	18397.2	9062.9	15974.0	6639.7	April 1-15
April 16-30	21244	97.58	28501	74.37	7744	18481.4	10736.9	16047.0	8302.6	April 16-30
May	20623	94.73	26879	76.72	7661	17941.1	10279.6	15577.9	7916.5	May
June	20478	94.07	25889	79.10	9139	17815.4	8676.2	15468.8	6329.6	June
July	20637	94.80	25421	81.18	10405	17953.3	7548.5	15588.5	5183.8	July
Annual Average 7/	21769.7	100.00		76.52	9996.8	18939.0	8942.2	16444.4	6447.6	Annual Average
SI CP average (42.5)	21870.5			76.39	10081.2					
SII CP average (20)	22021.9				10109.2	19158.4	9049.2	←		Sep-Ap2
SIII CP average (6)	23107.1				10194.0			17454.6	7260.6	← Nov-Ap2
						Input 5/ →	**9049.2**	Input 6/ →	**7260.6**	
August 1-31	20415.4	93.8	25388.2	80.41	10568.9	17760.8	7191.9	15421.4	4852.4	August 1-31
April 1-30	21195.4	97.4	28500.9	74.37	8539.4	18439.3	9899.9	16010.5	7471.1	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 1a).

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 CP average generation for the Step III hydro studies and is used to calculate the residual hydro loads.

7/ The Annual Average is for 2002-03 operating year, not a leap year.

TABLE 4
(English Units)
SUMMARY OF POWER REGULATIONS
FROM 2002-03 ASSURED OPERATING PLAN

	BASIC	DATA	STEP I			STEP II				STEP III			
PROJECTS	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE kaf	JANUARY 1937 PEAKING CAP MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE kaf	JANUARY 1945 PEAKING CAP MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE kaf	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	316	103	3008	204	117	104	3008	323	246	104
Kerr	3	160	1219	156	121	1219	154	112	123	1219	154	140	120
Thompson Falls	6	85	0	85	55	0	85	53	58	0	85	65	57
Noxon Rapids	5	554	231	549	152	0	554	134	201	0	554	176	200
Cabinet Gorge	4	239	0	239	101	0	239	90	117	0	239	114	117
Albeni Falls	3	50	1155	22	22	1155	20	22	21	1155	14	14	21
Box Canyon	4	74	0	71	46	0	70	45	48	0	69	56	46
Grand Coulee	24+3ss	6684	5185	6366	1967	5072	6369	1760	2356	5072	5763	1209	2262
Chief Joseph	27	2614	0	2614	1117	0	2614	1017	1364	0	2614	751	1286
Wells	10	840	0	840	420	0	840	389	487	0	840	293	443
Chelan	2	54	677	51	38	676	51	38	43	676	51	51	43
Rocky Reach	11	1267	0	1267	575	0	1267	532	691	0	1267	394	646
Rock Island	18	513	0	513	256	0	513	239	300	0	513	179	278
Wanapum	10	986	0	986	518	0	986	482	601	0	986	347	539
Priest Rapids	10	912	0	912	510	0	912	476	572	0	912	353	510
Brownlee	5	675	975	675	240	974	675	313	316	974	675	272	316
Oxbow	4	220	0	220	99	0	220	124	128	0	220	121	128
Ice Harbor	6	693	0	693	212	0	693	232	303	0	693	185	303
McNary	14	1127	0	1127	657	0	1127	638	800	0	1127	508	748
John Day	16	2484	535	2484	940	0	2484	922	1254	0	2484	723	1217
The Dalles	22+2f	2074	0	2074	749	0	2074	733	994	0	2074	591	972
Bonneville	18+2f	1147	0	1147	596	0	1147	580	730	0	1147	472	693
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	23407	9494	28500	23298	9049	11610	13000	22803	7261	11049
ADDITIONAL STEP I PROJECTS													
Libby	5	600	4980	557	196								
Boundary	6	1055	0	855	368								
Spokane River Plants	24	173	104	168	100								
Hells Canyon	3	450	0	410	192				NOT APPLICABLE TO STEP II & III				
Dworshak	3	450	2015	443	129								
Lower Granite	6	932	0	930	212								
Little Goose	6	932	0	928	205								
Lower Monumental	6	932	0	922	211								
Pelton, Rereg., & RB	7	423	274	418	127								
Total added step 1		5947	7373	5633	1739								
THERMAL INSTALLATION 2/				11545	10081		11545	10109			11545	10194	
RESERVES, HYDRO MAINTENANCE 3/				-4204	-11		-2299	0			-1996	0	
TOTAL RESOURCES				36381	21304		32544	19158			32352	17455	
STEP I, II, & III LOADS 4/				29683	21304		28734	19158			24949	17455	
SURPLUS				6698	0		3810	0			7403	0	
CRITICAL PERIOD	Starts			August 16, 1928			September 1, 1943				November 1, 1936		
	Ends			February 29, 1932			April 30, 1945				April 30, 1937		
	Length (Months)			42.5 Months			20 Months				6 Months		
	Study Identification			03-41			03-42				03-13		

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 III annual average load multiplied by the ratio of the PNW area January peak load to the PNW annual average load.

TABLE 4M
(Metric Units)
SUMMARY OF POWER REGULATIONS
FROM 2002-03 ASSURED OPERATING PLAN

	BASIC	DATA	STEP I			STEP II				STEP III 4/			
PROJECTS	NUMBER OF UNITS	NOMINAL INSTALLED PEAKING CAPACITY MW	USABLE STORAGE hm^3	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE hm^3	JANUARY 1943 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE hm^3	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW
HYDRO RESOURCES													
CANADIAN													
Mica			8635			8635							
Arrow			8758			8758							
Duncan			1727			1727							
Subtotal			19119			19119							
BASE SYSTEM													
Hungry Horse	4	428	3789	316	103	3710	204	117	104	3710	323	246	104
Kerr	3	160	1504	156	121	1504	154	112	123	1504	154	140	120
Thompson Falls	6	85	0	85	55	0	85	53	58	0	85	65	57
Noxon Rapids	5	554	285	549	152	0	554	134	201	0	554	176	200
Cabinet Gorge	4	239	0	239	101	0	239	90	117	0	239	114	117
Albeni Falls	3	50	1425	22	22	1425	20	22	21	1425	14	14	21
Box Canyon	4	74	0	71	46	0	70	45	48	0	69	56	46
Grand Coulee	24+3ss	6684	6396	6366	1967	6256	6369	1760	2356	6256	5763	1209	2262
Chief Joseph	27	2614	0	2614	1117	0	2614	1017	1364	0	2614	751	1286
Wells	10	840	0	840	420	0	840	389	487	0	840	293	443
Chelan	2	54	835	51	38	834	51	38	43	834	51	51	43
Rocky Reach	11	1267	0	1267	575	0	1267	532	691	0	1267	394	646
Rock Island	18	513	0	513	256	0	513	239	300	0	513	179	278
Wanapum	10	986	0	986	518	0	986	482	601	0	986	347	539
Priest Rapids	10	912	0	912	510	0	912	476	572	0	912	353	510
Brownlee	5	675	1203	675	240	1201	675	313	316	1201	675	272	316
Oxbow	4	220	0	220	99	0	220	124	128	0	220	121	128
Ice Harbor	6	693	0	693	212	0	693	232	303	0	693	185	303
McNary	14	1127	0	1127	657	0	1127	638	800	0	1127	508	748
John Day	16	2484	660	2484	940	0	2484	922	1254	0	2484	723	1217
The Dalles	22+2f	2074	0	2074	749	0	2074	733	994	0	2074	591	972
Bonneville	18+2f	1147	0	1147	596	0	1147	580	730	0	1147	472	693
Kootenay Lake	0	0	830	0	0	830	0	0	0	830	0	0	0
Coeur d'Alene Lake	0	0	275	0	0	275	0	0	0	275	0	0	0
Total Base and Canadian System Hydro 1/		23880	36320	23407	9494	35155	23298	9049	11610	16036	22803	7261	11049
ADDITIONAL STEP I PROJECTS													
Libby	5	600	6143	557	196								
Boundary	6	1055	0	855	368								
Spokane River Plants	24	173	128	168	100								
Hells Canyon	3	450	0	410	192				NOT APPLICABLE TO STEP II & III				
Dworshak	3	450	2486	443	129								
Lower Granite	6	932	0	930	212								
Little Goose	6	932	0	928	205								
Lower Monumental	6	932	0	922	211								
Pelton, Rereg., & RB	7	423	338	418	127								
Total added step 1		5947	9095	5633	1739								
THERMAL INSTALLATION 2/				11545	10081		11545	10109			11545	10194	
RESERVES, HYDRO MAINT. 3/				-4204	-11		-2299	0			-1996	0	
TOTAL RESOURCES				36381	21304		32544	19158			32352	17455	
STEP I, II, & III LOADS 4/				29683	21304		28734	19158			24949	17455	
SURPLUS				6698	0		3810	0			7403	0	
CRITICAL PERIOD	Starts		August 16, 1928			September 1, 1943				November 1, 1936			
	Ends		February 29, 1932			April 30, 1945				April 30, 1937			
	Length (Months)		42.5 Months			20 Months				6 Months			
	Study Identification		03-41			03-42				03-13			

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 III annual average load multiplied by the ratio of the PNW area January peak load to the PNW annual average load.

TABLE 5
(English & Metric Units)
COMPUTATION OF CANADIAN ENTITLEMENT FOR
2002-03 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S. (From 03-42)
B. Optimum Power Generation in the U.S. Only (From 03-12)
C. Optimum Power Generation in the U.S. and a 0.5 Million Acre-Feet (0.6 km3) Reduction in Total Canadian Treaty Storage (From 03-22)

	CAPACITY ENTITLEMENT		
Determination of Dependable Capacity Credited to Canadian Storage (MW)	(A)	(B)	(C)
Step II - Critical Period Average Generation 1/	9049.2	9050.3	9012.0
Step III - Critical Period Average Generation 2/	7260.6	7260.6	7260.6
Gain Due to Canadian Storage	1788.6	1789.7	1751.4
Average Critical Period Load Factor in percent 3/	76.39	76.39	76.39
Dependable Capacity Gain 4/	2341.4	2342.9	2292.7
Canadian Share of Dependable Capacity 5/	1170.7	1171.4	1146.4

	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/	8942.9	8944.0	8906.1
Thermal Displacement Energy 7/	2343.6	2338.1	2363.1
Other Usable Secondary Energy 8/	129.6	130.7	133.1
System Annual Average Usable Energy	11416.1	11412.8	11402.3
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6448.1	6448.1	6448.1
Thermal Displacement Energy 7/	3431.4	3431.4	3431.4
Other Usable Secondary Energy 8/	467.7	467.7	467.7
System Annual Average Usable Energy	10347.2	10347.2	10347.2
Average Annual Usable Energy Gain 9/	1068.9	1065.6	1055.1
Canadian Share of Average Annual Energy Gain 5/	534.5	532.8	527.6

1/ Step II values were obtained from the 03-42, 03-12, and 03-22 studies, respectively.
2/ Step III values were obtained from the 03-13 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

	1998-99	1999-00	2000-01	2001-02	2002-03
AVERAGE PNWA ENERGY LOAD					
Annual Load (MW)	20479.6	20817.8	21107.8	21641.7	21769.7
Annual/January Load (%)	86.3	85.9	87.4	88.0	88.0
Critical Period (CP) Load Factor (%)	75.6	75.3	75.1	76.7	76.4
Annual Firm Exports 1/	1075.3	1202.7	1067.1	1156.3	1317.3
Annual Firm Surplus (MW) 2/	534.6	708.1	739.7	313.7	323.7
THERMAL INSTALLATIONS (MW) 3/					
January Peak Capability	11003	11341	11520	11433	11545
CP Energy	8462	9019	9521	9496	10081
CP Minimum Generation	789	1071	858	853	622
Average Annual System Export Sales	1265	1392	1413	997	1419
Average Annual Displaceable Market	6345	6490	7179	7493	7958
HYDRO CAPACITY (MW)					
Total Installed	29786	29786	29836	29827	29827
Base System	23856	23856	23889	23880	23880
STEP I/II/III CP (MONTHS)	42/20/6.5	42/20/7	42/20/7	42.5/20/6.5	42.5/20/6
BASE STREAMFLOWS AT THE DALLES (cfs) 4/					
Step I 50-yr. Average Streamflow	181664	181664	181663	181663	181663
Step I CP Average	114496	114496	114496	114401	114401
Step II CP Average	101537	101525	101525	101525	101525
Step III CP Average	58483	64960	64959	58482	64878
BASE STREAMFLOWS AT THE DALLES (m^3/s) 4/					
Step I 50-yr. Average Streamflow	5144.15	5144.15	5144.12	5144.08	5144.12
Step I CP Average	3242.16	3242.16	3242.16	3239.43	3239.46
Step II CP Average	2875.20	2874.87	2874.85	2874.83	2874.86
Step III CP Average	1656.05	1839.46	1839.43	1656.00	1837.14
CAPACITY BENEFITS (MW)					
Step II CP Generation	9064.1	9080.4	9032.9	9055.6	9049.2
Step III CP Generation	6773.9	6878.8	6859.6	6865.3	7260.6
Step II Gain over Step III	2290.2	2201.7	2173.3	2190.3	1788.6
CANADIAN ENTITLEMENT	1514.7	1461.9	1447.3	1427.1	1170.7
Change due to Mica Reoperation	-0.4	0.2	0.0	0.0	-0.7
Benefit in Sales Agreement	416.0	200.0	192.0	187.0	167.0
ENERGY BENEFITS (aMW)					
Step II Annual Firm Hydro	9000.0	8990.3	8967.3	8966.5	8942.9
Step II Thermal Displacement	2101.3	2129.5	2183.3	2306.6	2343.6
Step II Other Usable Secondary	188.3	193.5	148.7	135.8	129.6
Step II System Annual Average Usable	11289.6	11313.3	11299.3	11408.9	11416.1
Step III Annual Firm Hydro	6502.1	6422.2	6541.1	6573.9	6448.1
Step III Thermal Displacement	3066.8	3182.0	3239.8	3294.0	3431.4
Step III Other Usable Secondary	595.3	590.1	501.5	475.9	467.7
Step III System Annual Average Usable	10164.2	10194.3	10282.4	10343.8	10347.2
CANADIAN ENTITLEMENT	562.7	559.5	508.4	532.6	534.5
Change due to Mica Reoperation	-4.1	-0.8	0.7	0.4	1.7
ENTITLEMENT in Sales Agreement	215.0	103.0	99.0	95.0	93.0
STEP II PEAK CAPABILITY (MW)	32074	32421	32481	32501	32544
STEP II PEAK LOAD (MW)	27317	28386	28779	27650	28734
STEP III PEAK CAPABILITY (MW)	31793	32206	32268	32260	32352
STEP III PEAK LOAD (MW)	23391	24318	24983	24034	24949

FOOTNOTES FOR TABLE 6

1. Average Annual Firm Exports do not include the firm surplus shape or the new thermal installation power used outside the Region (Exports to shape thermal installations).

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

AOP Study	Amount Shaped (MW)
1998-99	3199 May and June.
1999-00	4237 May and June.
2000-01	471 1 August through April 30 and
	1537 May through July.
2001-02	1877 May and June.
2002-03	1937 May and June.

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

4. The 1990 level modified flows were used and no additional irrigation depletions were anticipated for the 2002-03 level. There is, however, an adjustment for Grand Coulee pumping and return flow.

CHART 1
2002-03 DDBP STUDIES
DURATION CURVES OF 30 YEARS MONTHLY HYDRO GENERATION (aMW)