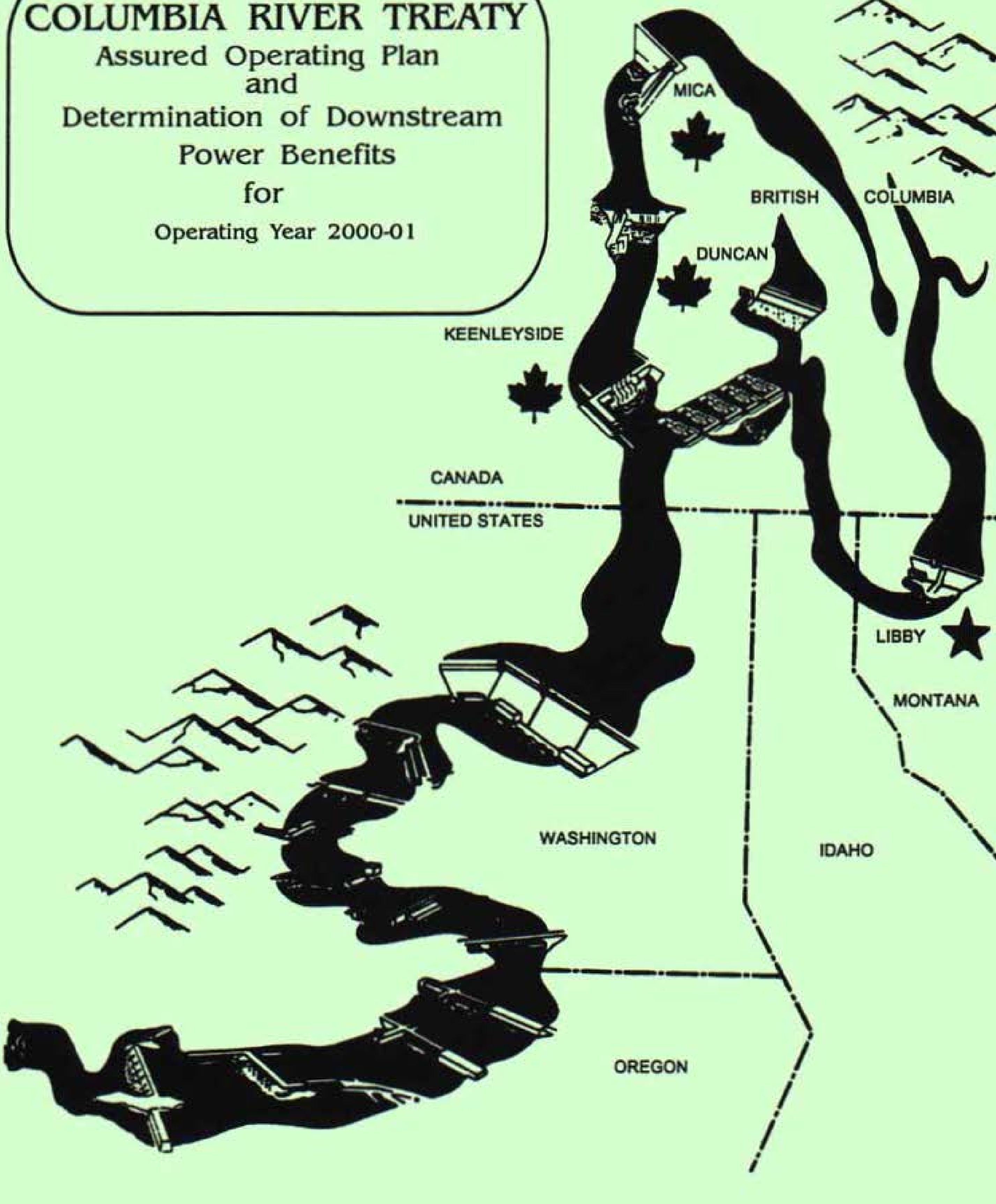
COLUMBIA RIVER TREATY

Assured Operating Plan
and
Determination of Downstream
Power Benefits
for
Operating Year 2000-01



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 2000-01 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 2000-01" and "Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2000-01," both dated January 2000, shall be the Assured Operating Plan and Determination of Downstream Power Benefits for the Operating Year 2000-01.

In order to complete studies associated with the 2000-01 Assured Operating Plan and Determination of Downstream Power benefits so that this Agreement could be concluded, the Entities executed on 30 January 1995 an agreement called "Columbia River Treaty Entity Agreement on the Preparation of the 1998-99, 1999-00, 2000-01 Assured Operating Plan and Determination of Downstream Power Benefits Studies" which provided for certain agreed procedures to be used in studies preparatory to this Agreement.

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 2000-01

TABLE OF CONTENTS

HYDROELECTRIC OPERATING PLAN
ASSURED OPERATING PLAN
FOR OPERATING YEAR 2000-01

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:

- Principles[2] and on Changes to Procedures[3] for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, signed 28 July and 12 August 1988, respectively,
- The "Columbia River Treaty Entity Agreement on the 1998/99, 1999/2000, and 2000/2001 Assured Operating Plan and Determination of Downstream Power Benefit Studies," dated 5 April 1995.[4]

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), and the related rule curves and data used to compute the individual Operating Rule Curves (ORC).

(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 is the first AOP to include 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 2000-01 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 2000-01 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 2000-01 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-month critical period for the United States system resulting from the low flows during the period from 1 September 1928 through 29 February 1932. With the exceptions of Brownlee, Dworshak, and John Day, 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 were 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 2000-01 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 2000-01 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 2000-01 AOP and from studies designed to achieve optimum generation in the United States alone.

(b) Maximum Permitted Reduction in Downstream Power Benefits

Separate Step II system regulation studies were developed reflecting (i) Canadian storage operation for optimum generation in both Canada and the United States, using the Mica Project operating criteria described in section 5(c) below, and (ii) Canadian storage operation for optimum generation in the United States alone. Using these Mica Project operating criteria, there is a 0.7 aMW increase in the Canadian Entitlement for average annual usable energy and no change in the dependable capacity compared to an operation for optimum generation in the United States alone.

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

4. Rule Curves

The operation of Canadian storage during the 2000-01 Operating Year shall be guided by an ORC for the whole of Canadian storage, Flood Control Storage Reservation Curves for the individual projects, CRC's, and operating rules for specific projects. The ORC is derived from the various curves described below. These ORC's are first determined for the individual Canadian projects and then summed to yield the Composite ORC for the whole of Canadian storage, in accordance with paragraph VII(2) of the Protocol.

(a) Critical Rule Curve

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

(b) Refill Curves

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 VRCs 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 km^3 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 2000-01, 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, draft rates, etc. These constraints are included as part of this operating plan, as found in Appendix A1 (English units) or Appendix A2 (Metric units).

The following rules, used in the 30-year System Regulation Study, will apply to the operation of Canadian storage in the 2000-01 Operating Year.

(a) Operation Above ORC

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

(b) Operation Below ORC

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

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

(c) Mica Project Operation

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

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

Revelstoke, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile, and Waneta have been included in the 2000-01 AOP and have been operated as run-of-river projects. Generation at Arrow was modeled in the studies. Corra Linn and Kootenay Canal were included in the study and operated in accordance with criteria that closely approximates International Joint Commission rules for Kootenay Lake.

6. Implementation

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

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

(k) preparation and implementation of detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under the plans referred to in Annexes A and B."

The 2000-01 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 2000-01 DOP. Failing agreement on updating the data and/or criteria, the 2000-01 DOP will include the rule curves, Mica operating criteria, and other data and criteria provided in this AOP. Actual operation during the 2000-01 Operating Year shall be guided by the DOP.

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

During the storage drawdown season, Canadian storage should not be drafted below its period-end point at any time during the period unless it can be conservatively demonstrated that sufficient inflow is available, in excess of the minimum outflow required to serve power demand, to refill the reservoir to its end-of-period value as required. During the storage evacuation and refill season, operation will be consistent with the Flood Control Operating Plan. When refill of Canadian storage is being guided by Flood Control Refill Curves, such curves will be computed on a day-by-day basis using the residual volume-of-inflow forecasts depleted by the volume required for minimum outflow, unless higher flows are required to meet firm load, from each day through the end of the refill season. [15]

7. Canadian Entitlement

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

(a) Delivery of the Canadian Entitlement

The Treaty specifies return of the Canadian Entitlement at a point near Oliver, British Columbia, unless otherwise agreed by the Entities. Because no cross border transmission exists at any point on the Canada-United States of America boundary near Oliver, the Entities completed an agreement on Aspects of the Canadian Entitlement Return for 1 April 1998 through 31 March 2003,[17] executed 28 July 1992. This agreement has now been replaced by the Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for 1 April 1998 through 15 September 2024, dated 29 March 1999.[18] This arrangement covers the full 1 August 2000 through 31 July 2001 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 Return for 1 April 1998 through 15 September 2024,[19] specifies the scheduling guidelines for delivery of the Canadian Entitlement.

8. Summary of Changes from Previous Year

Data from the five most recent AOP's are summarized in Table 11. Firm energy shifting was not included in these studies. Some changes to the format of Table 11 for this year were: the hydro firm load for each period was listed instead of the secondary load; the Canadian Treaty CRC1 for different periods were in storage content instead of draft content; and the 50-yr average Canadian Treaty storage for these periods were added for information. An explanation of the more important changes compared to last year's studies follows.

(a) Loads and Non-Hydro Resources

Loads for the 2000-01 AOP were based on the 1994 Whitebook medium case forecast developed by BPA in September 1994. The Pacific Northwest Area (PNWA) firm energy load increased by 290 aMW. Loads increased in every period with the exception of January, which decreased by 69 aMW. The total exports, not including firm surplus energy, decreased by 136 aMW. The decrease in exports is mainly due to the decreased Canadian Entitlement Return. It was assumed that 1/3 of the Entitlement Return was to remain in the PNWA. The surplus firm energy increased by 32 aMW with shaping of 471 aMW 1 August through 30 April, and 1537 aMW in May through July.

The total annual energy capability of the thermal installations increased by 500 aMW. Major thermal resource changes included:

- Decrease of 10 aMW due to the termination of two Small Thermal projects: EWEB's Willamette Steam Plant and Puget's Shuffleton,
- Combustion Turbine resource increases of 285 aMW due to the addition of Clark's new Cogentrix and WWP's Rathdrum now reporting energy,
- Co-generation increased 99 aMW due to an increase in PP&L miscellaneous cogeneration and facilities upgrade at PGE's Coyote Springs,
- Centralia large thermal generation increased by 58 aMW,
- Thermal Non-Utility Generation (NUGs) decreased by 20 aMW mostly due to the termination of Idaho's NUG's,
- Imports increased by 87 aMW due to the addition of five new BPA imports and to the Glendale to PGE Seasonal Exchange. PG&E-to-WWP was the only import to terminate. Both the PP&L (WYM) to PP&L and Montana Thermal Import increased and showed different monthly shaping from the previous year's data.

(b) Operating Procedures

The 1990 level modified base flows were again used, with no additional depletion to the 2001 level, based on the recommendation of the Columbia River Water Management Group. Grand Coulee pumping adjustments and return flow, however, were included.

The Entities completed a Step I refill study and incorporated the resulting PDR's in the 2000-01 DDPB. New LRC's were developed for the Step I system based on 1937 water conditions. These studies are consistent with PNCA procedures, which includes starting the system full 1 August 1936 and adjusting the load until the system is empty 30 April 1937. The end of period contents in January, February, March, and 15 April are the LRC's for all major reservoir projects.

Plant data for Arrow, Ice Harbor, Lower Granite, Little Goose, Lower Monument, Dworshak, Rock Island, and Chief Joseph were revised. However, Arrow, and Rock Island were the only projects to show a significant change in generation. Arrow had generation for the first time, and the Rock Island generation decreased due to updated generation vs. discharge data.

Notable changes in non-power constraints include a revision of spill data, fisheries requirements, and the operation of Dworshak, John Day, and the non-base system Lower Snake projects. For further details, see Appendix A1 (English units) or Appendix A2 (Metric units).

The spill and bypass assumptions for the 2000-01 DDPB studies are different from the 1999-00 DDPB studies as follows:

- Fish bypass installations previously forecast to be installed at Bonneville, The Dalles, John Day, Ice Harbor, Wanapum, Rock Island, and Rocky Reach in the 1999-00 DDPB studies were removed from the hydroregulation model; and

- All proportional fish spill for the base system (% of fish spill) was removed. Most projects showed a decrease in generation. The only fish spill remaining was fixed fish spill at Wells and Rock Island. Ice Harbor and The Dalles had increased other spill. Priest Rapids was the only project to show increased generation since in the AOP00 the bypass was installed and fish spill was operative. Fixed fish spill remained at Wells and Rock Island. Only the non-sluiceway component of other spill remained at Ice Harbor and The Dalles.

Dworshak began the Step I critical period 80 feet (24.38 meters (m)) below full, an additional 50 feet (15.24 m) lower than the previous year's study, and did not empty at the end of the critical period, remaining on URC. Other Dworshak requirements include: operate to minimum flow requirements or URC 15 August through 15 April, meet flows for fish through July, and draft to meet Lower Granite flows of 50000 cfs (1,415.84 m^3/s) in August, when reservoir elevation is above 1520 ft (463.30 m) [(395.7 ksfd), or (968.1 hm^3)].

Other projects that showed a significant loss of generation were: John Day due to operation to a lower minimum operating pool, and Lower Granite, Little Goose, and Lower Monumental because of the inclusion of fish constraints.

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 Principles for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies," dated 28 July 1988.

3 "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.

4 "Columbia River Treaty Entity Agreement on the 1998/99, 1999/2000, and 2000/2001 Assured Operating Plan and Determination of Downstream Power Benefit Studies," dated 5 April 1995.

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 01-41," dated 21 October 1996.

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.

TABLE 1
(English Units)
MICA PROJECT OPERATING CRITERIA
2000-01 ASSURED OPERATING PLAN

		Target Operation			
Period	End of Previous Period Arrow Storage Content (ksfd)	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	17000			
	0 - 1650	26000			
August 16-31	3400 - FULL	-	3529.2	15000	0.0
	1450 - 3400	24000			
	0 - 1450	27000			
September	3460 - FULL	-	3529.2	10000	0.0
	1600 - 3460	22000			
	0 - 1600	27000			
October	3150 - FULL	-	3386.2	10000	0.0
	1300 - 3150	22000			
	0 - 1300	28000			
November	3070 - FULL	-	3056.2	12000	0.0
	2320 - 3070	22000			
	0 - 2320	28000			
December	2850 - FULL	25000		21000	0.0
	1930 - 2850	27000			
	0 - 1930	29000			
January	2430 - FULL	26000		15000	106.2
	1270 - 2430	28000			
	0 - 1270	30000			
February	2080 - FULL	23000		15000	0.0
	2045 - 2080	21000			
	0 - 2045	26000			
March	1680 - FULL	22000		15000	0.0
	150 - 1680	27000			
	0 - 150	32000			
April 1-15	1810 - FULL	26000		12000	0.0
	50 - 1810	-	136.2		
	0 - 50	12000			
April 16-30	1060 - FULL	-	106.2	10000	0.0
	20 - 1060	-	0.0		
	0 - 20	10000			
May	1845 - FULL	8000		8000	0.0
	220 - 1845	10000			
	0 - 220	23000			
June	2080 - FULL	8000		8000	0.0
	440 - 2080	10000			
	0 - 440	17000			
July	3175 - FULL	-	3456.2	8000	0.0
	1680 - 3175	10000			
	0 - 1680	21000			

Notes:

1/ A maximum outflow of 34000 cfs will apply if the target end-of-period storage content @ Mica is less than 3529.2 ksfd in every month except April, May, and June. For these periods, the maximum outflow is 29000 cfs in April 1-15, 27000 cfs in April 16-30, 30000 cfs in May and 33000 cfs in June.

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

TABLE 2
COMPARISON OF 2000-01 ASSURED OPERATING PLAN STUDY RESULTS

Study 01-41 provides Optimum Generation in Canada and in the United States.
Study 01-11 provides Optimum Generation in the United States only.

	Study No. 01-41	Study No. 01-11	Net Gain	Weight	Value
1. Firm Energy Capability (aMW)					
U.S. System 1/	11963.3	11963.6	-0.3		
Canada 2/, 3/	2901.8	2841.0	60.8		
Total	14865.1	14804.6	60.5	3	181.5
2. Dependable Peaking Capacity (MW)					
U.S. System 4/	30867.0	30869.0	-2.0		
Canada 2/, 5/	5330.0	5366.0	-36.0		
Total	36197.0	36235.0	-38.0	1	-38.0
3. Average Annual Usable Secondary Energy (aMW)					
U.S. System 6/	3139.2	3123.0	16.2		
Canada 2/, 7/	231.0	274.6	-43.6		
Total	3370.2	3397.6	-27.4	2	-54.8
			Net Change in Value =		88.7

1/ U.S. System firm energy capability was determined over the U.S. system critical period beginning 1 September 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)
2000 - 01 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	3529.2	3529.2	3146.7	3299.0	2963.5	2381.5	1894.6	1899.9	1578.8	858.2	383.9	844.2	2491.6	3388.1
1929-30	3529.2	3520.3	3150.8	2568.9	1462.5	1121.6	749.4	733.0	580.4	13.0	0.0	293.9	925.1	2269.7
1930-31	2861.6	2948.8	2941.0	2170.6	1151.2	1038.4	878.0	782.4	636.2	2.8	0.0	0.0	816.4	1867.9
1931-32	1685.6	1802.5	1515.8	1147.5	513.5	9.1	9.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	3579.6	3579.6	3536.6	3113.5	3030.1	2675.9	1698.6	876.5	968.2	508.5	359.0	896.1	2402.0	3033.0
1929-30	3338.5	3327.1	3214.6	3429.2	3199.4	2255.2	771.5	833.1	839.7	606.7	536.1	574.5	2393.6	3330.4
1930-31	3323.6	3305.8	3320.6	3210.8	3236.6	2165.2	644.5	556.0	782.1	539.7	346.3	502.2	2185.9	2228.6
1931-32	2471.8	2045.2	1920.1	1503.8	1422.8	1206.0	473.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	705.8	705.8	688.9	690.0	566.6	345.3	283.0	275.0	222.8	231.2	239.6	340.0	572.2	695.0
1929-30	705.8	696.7	617.8	474.4	281.1	111.2	1.2	0.1	8.8	32.0	55.3	170.0	320.0	473.0
1930-31	538.8	593.8	601.8	500.6	373.2	169.1	18.3	6.9	9.0	22.2	2.0	28.5	109.0	238.3
1931-32	240.0	200.0	170.0	160.0	1.3	8.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	7814.6	7814.6	7372.2	7102.5	6560.2	5402.7	3876.2	3051.4	2769.8	1597.9	982.5	2080.3	5465.8	7116.1
1929-30	7573.5	7544.1	6983.2	6472.5	4943.0	3488.0	1522.1	1566.2	1428.9	651.7	591.4	1038.4	3638.7	6073.1
1930-31	6724.0	6848.4	6863.4	5882.0	4761.0	3372.7	1540.8	1345.3	1427.3	564.7	348.3	530.7	3111.3	4334.8
1931-32	4397.4	4047.7	3605.9	2811.3	1937.6	1223.1	483.6	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
2000-01 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	950.0	1514.2	2117.5	2295.8	2361.1	2377.6	2372.4	1885.0	1364.8	1135.0	943.2	1193.1	2398.4	3529.2
VARIABLE REFILL CURVES (KSFD)														
1928-29							2977.6	2676.1	2423.2	2297.3	2247.9	2145.7	2830.8	3529.2
1929-30							1953.6	1612.5	1349.0	1242.6	1325.2	1533.1	2546.6	*
1930-31							2213.1	1880.9	1613.2	1484.8	1497.9	1553.2	2621.8	*
1931-32							1261.4	1132.3	1087.7	990.6	1045.9	1256.4	2502.3	*
1932-33							1165.7	1072.0	1044.7	945.6	954.7	1152.7	2338.9	*
1933-34							628.1	310.3	241.8	158.3	264.5	898.7	2591.6	*
1934-35							1631.1	1442.6	1343.5	1252.4	1249.2	1360.1	2417.4	*
1935-36							1464.2	1253.2	1121.0	1006.8	1032.7	1303.9	2676.4	*
1936-37							2965.8	2643.7	2376.0	2239.3	2238.2	2159.4	2863.1	*
1937-38							1538.9	1426.8	1382.6	1289.5	1307.7	1481.6	2593.8	*
1938-39							2017.2	1753.5	1499.5	1397.2	1432.7	1576.7	2854.6	*
1939-40							1804.2	1496.6	1259.7	1151.5	1209.1	1369.6	2614.4	*
1940-41							2395.0	2083.7	1835.7	1726.4	1821.0	1933.5	2844.6	*
1941-42							2140.6	1952.4	1828.2	1708.2	1703.1	1783.8	2746.9	*
1942-43							2174.6	2040.4	1998.6	1895.4	1961.7	2114.4	2832.2	*
1943-44							3080.1	2735.3	2481.4	2347.7	2324.8	2266.6	3001.8	*
1944-45							2946.2	2664.7	2446.0	2331.8	2290.3	2193.3	2920.8	*
1945-46							958.1	815.5	768.9	659.9	687.8	949.6	2496.7	*
1946-47							1076.9	988.0	970.5	882.8	931.1	1216.2	2567.2	*
1947-48							1025.9	916.3	883.5	769.9	784.3	1009.9	2453.9	*
1948-49							2721.9	2587.4	2529.3	2425.1	2408.2	2397.9	3225.4	*
1949-50							1381.3	1232.4	1176.2	1066.9	1080.6	1233.0	2265.2	*
1950-51							1372.5	1271.3	1247.2	1155.6	1196.3	1353.2	2626.7	*
1951-52							1779.2	1635.4	1586.2	1470.7	1474.5	1651.2	2774.0	*
1952-53							2060.3	1934.5	1895.1	1791.9	1768.6	1807.7	2740.9	*
1953-54							938.4	822.5	806.7	711.1	730.1	925.3	2237.3	*
1954-55							1696.0	1598.2	1574.9	1484.9	1493.1	1576.8	2431.7	*
1955-56							1244.5	1129.0	1084.5	977.9	997.1	1250.2	2541.2	*
1956-57							1413.0	1290.3	1260.6	1166.0	1182.6	1337.1	2871.8	*
1957-58							1246.8	1137.0	1113.6	1024.5	1059.2	1232.9	2634.3	*
LIMITING RULE CURVE (KSFD)							628.1	310.3	114.3	0.0				
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVES														
	3000	3000	3000	3000	3000	3000	3000	20000	20000	20000	20000	20000	20000	20000
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
80 MAF --							3000	10000	10000	10000	12000	20000	20000	20000
95 MAF --							3000	3000	3000	8000	12000	18000	20000	20000
110 MAF --							3000	3000	3000	8000	12000	18000	20000	20000

TABLE 5
(English Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2000-01 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	0.0	541.4	1966.0	2114.1	2584.1	3218.6	3272.0	2787.3	2105.7	2110.0	2009.3	2630.5	3421.0	3579.6
VARIABLE REFILL CURVES (KSFD)														
1928-29							3579.6	3579.6	3380.7	3481.8	3579.6	3572.4	3579.6	3579.6
1929-30							2684.7	2386.8	2096.6	2002.5	2389.2	2963.9	3547.4	*
1930-31							2892.9	2549.0	2236.6	2359.6	2593.4	2798.7	3560.5	*
1931-32							1652.7	1071.0	172.7	1.1	0.0	1032.0	2769.6	*
1932-33							*	*	*	*	212.9	1140.8	2707.5	*
1933-34							*	*	*	*	222.2	1554.4	3256.4	*
1934-35							*	*	822.6	917.2	1256.5	1833.5	2953.2	*
1935-36							*	*	773.3	668.4	872.0	1829.2	3415.3	*
1936-37							3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	*
1937-38							1652.7	1071.0	460.4	683.5	1128.8	1915.3	3098.4	*
1938-39							2820.7	2465.1	2114.4	2158.7	2481.0	2883.8	3579.6	*
1939-40							2555.5	2244.4	1946.9	1859.3	2255.3	2663.9	*	*
1940-41							3366.7	3213.3	2960.6	3200.9	3579.6	3579.6	*	*
1941-42							2156.2	2033.7	2096.9	2348.5	2675.4	3006.1	*	*
1942-43							1723.5	1728.9	1970.2	2303.7	2726.8	3306.7	3573.2	*
1943-44							3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	*
1944-45							*	*	3536.7	*	*	*	*	*
1945-46							1652.7	1071.0	172.7	1.1	139.0	1135.0	2913.1	*
1946-47							*	*	251.0	307.7	582.9	1553.9	3066.2	*
1947-48							*	*	172.7	98.8	307.4	1216.2	2910.6	*
1948-49							*	1375.1	1639.3	2001.6	2401.1	2997.1	3579.6	*
1949-50							*	1071.0	172.7	77.7	447.9	1197.5	2592.9	*
1950-51							*	*	385.1	409.2	902.8	1662.3	3201.4	*
1951-52							*	*	381.4	719.6	1123.1	2018.1	3315.7	*
1952-53							*	*	1076.5	1437.0	1774.2	2299.4	3263.5	*
1953-54							*	*	172.7	1.1	0.0	839.6	2581.7	*
1954-55							*	*	*	537.3	974.9	1602.9	2559.2	*
1955-56							*	*	*	1.1	158.2	1257.2	2956.6	*
1956-57							*	*	*	*	361.6	1184.9	3410.6	*
1957-58							*	*	*	*	241.2	1108.5	3072.6	*
LIMITING RULE CURVE (KSFD)							1652.7	1071.0	172.7	1.1				
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVES														
	5000	5000	5000	5000	5000	5000	5000	40000	40000	40000	40000	40000	45000	50000
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
80 MAF –							5000	20000	22000	25000	30000	35000	42000	44000
95 MAF –							5000	5000	5000	8000	20000	23000	33000	34300
110 MAF –							5000	5000	5000	8000	20000	23000	33000	34300

TABLE 6
(English Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2000-01 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	114.3	185.2	251.5	282.2	299.7	310.9	321.1	291.1	261.8	254.0	246.2	360.0	540.9	705.8
VARIABLE REFILL CURVES (KSFD)														
1928-29							486.6	451.7	427.2	420.8	417.7	447.7	595.2	705.8
1929-30							484.9	449.7	424.9	418.2	429.1	468.4	606.6	*
1930-31							429.5	395.5	374.2	372.7	376.0	417.3	595.2	*
1931-32							9.3	1.4	15.2	32.5	82.0	219.5	501.2	*
1932-33							1.2	0.0	0.0	0.1	0.0	41.7	366.8	*
1933-34							*	8.8	27.9	51.2	127.8	279.7	559.2	*
1934-35							146.4	135.1	141.3	148.1	168.3	272.8	500.9	*
1935-36							112.6	92.9	86.1	89.3	111.3	246.6	535.6	*
1936-37							434.5	399.5	376.7	370.2	368.0	409.7	577.4	*
1937-38							80.0	79.4	91.1	107.3	143.8	275.4	525.8	*
1938-39							281.5	252.9	233.8	231.4	245.1	329.1	578.0	*
1939-40							265.8	241.7	229.9	237.1	252.2	331.2	566.6	*
1940-41							346.9	320.5	304.7	313.1	335.4	408.6	590.3	*
1941-42							253.7	244.9	246.4	254.1	275.1	368.5	566.4	*
1942-43							210.8	205.7	215.6	226.4	261.2	386.4	558.7	*
1943-44							503.6	473.2	453.6	449.3	447.7	480.8	625.4	*
1944-45							410.7	384.0	367.9	365.1	364.7	408.5	582.8	*
1945-46							1.2	0.0	0.0	0.1	10.6	165.2	494.6	*
1946-47							*	*	*	10.4	53.7	208.3	507.3	*
1947-48							37.2	33.9	46.3	56.8	90.2	225.4	517.6	*
1948-49							265.8	257.5	263.9	271.8	297.7	399.7	619.5	*
1949-50							68.8	61.5	70.5	79.4	110.3	234.2	461.8	*
1950-51							1.2	0.0	3.6	13.3	55.1	199.8	492.8	*
1951-52							98.3	92.5	104.6	115.0	147.5	284.8	537.9	*
1952-53							97.2	91.7	103.0	114.1	144.6	263.1	504.2	*
1953-54							1.2	0.0	0.0	0.1	0.0	126.8	434.9	*
1954-55							35.0	31.4	42.7	55.2	87.3	212.7	438.6	*
1955-56							1.2	0.0	0.0	0.1	4.8	173.4	490.5	*
1956-57							49.4	39.6	48.1	59.3	96.0	226.9	554.8	*
1957-58							1.2	0.0	0.0	0.1	18.5	164.1	506.6	*
LIMITING RULE CURVE (KSFD)							1.2	0.0	0.0	0.1				
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVES														
	100	100	100	100	100	100	100	1500	1500	1500	1500	1500	2000	2000
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
					80 MAF –		100	1000	1000	1000	2000	2000	2000	2200
					95 MAF –		100	100	100	100	400	600	1800	2000
					110 MAF –		100	100	100	100	400	600	1800	2000

TABLE 7
(English Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2000-01 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)
2000-01 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)
2000-01 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)
2000-01 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7372.2	7102.5	6560.2	5802.2	5768.9	4978.3	3946.3	3499.0	3198.7	4183.6	6484.8	7814.6
1929-30	"	"	"	"	"	"	4959.4	4290.4	3707.4	3391.5	3198.7	4183.6	6480.3	"
1930-31	"	"	"	"	"	"	5427.1	4718.8	3946.3	3499.0	3198.7	4183.6	6468.3	"
1931-32	"	"	"	"	"	"	2923.4	2204.7	1275.6	1024.2	1025.2	2444.6	5762.4	"
1932-33	"	"	"	"	"	"	2819.6	2143.0	1217.4	946.8	1156.1	2335.2	5413.2	"
1933-34	"	"	"	"	"	"	2282.0	1390.1	442.4	210.6	613.7	2732.8	6307.2	"
1934-35	"	"	"	"	"	"	3430.2	2579.1	2231.6	2117.7	2035.0	3106.0	5858.7	"
1935-36	"	"	"	"	"	"	3229.5	2389.7	1959.8	1746.5	1926.5	3268.9	6442.5	"
1936-37	"	"	"	"	"	"	5634.3	4950.8	3946.3	3499.0	3198.7	4183.6	6459.2	"
1937-38	"	"	"	"	"	"	3271.6	2577.2	1934.1	1925.8	2191.2	3269.5	6115.8	"
1938-39	"	"	"	"	"	"	4883.2	3987.5	3242.5	2964.1	2919.0	4152.7	6484.8	"
1939-40	"	"	"	"	"	"	4625.5	3856.4	3322.0	3121.5	3103.4	4154.8	6479.2	"
1940-41	"	"	"	"	"	"	5768.9	4889.3	3886.6	3457.2	3181.8	4167.8	6437.1	"
1941-42	"	"	"	"	"	"	4550.5	3790.0	2757.0	2378.9	2294.5	3487.1	6479.0	"
1942-43	"	"	"	"	"	"	4108.9	3798.5	2765.5	2438.4	2486.3	2922.6	5439.4	"
1943-44	"	"	"	"	"	"	5768.9	4978.3	3946.3	3499.0	3198.7	4183.6	6484.8	"
1944-45	"	"	"	"	"	"	5276.4	4315.2	3486.1	3061.5	2933.5	3921.9	6411.3	"
1945-46	"	"	"	"	"	"	2612.0	1886.5	941.6	661.1	837.4	2249.8	5899.3	"
1946-47	"	"	"	"	"	"	2730.8	2059.0	1221.5	1200.9	1567.7	2955.3	6065.1	"
1947-48	"	"	"	"	"	"	2715.8	2021.2	1102.5	925.5	1157.2	2451.5	5882.1	"
1948-49	"	"	"	"	"	"	4290.9	3526.0	2838.1	2533.6	2565.4	4047.6	6484.8	"
1949-50	"	"	"	"	"	"	3102.8	2364.9	1414.4	1210.1	1456.6	2490.8	4959.3	"
1950-51	"	"	"	"	"	"	3026.4	2342.3	1635.9	1557.5	1901.1	2748.4	6185.8	"
1951-52	"	"	"	"	"	"	3530.2	2771.9	2025.7	1920.1	2133.7	3078.1	5760.5	"
1952-53	"	"	"	"	"	"	3810.2	3036.4	2652.6	2264.1	2200.8	2904.0	6009.7	"
1953-54	"	"	"	"	"	"	2590.3	1893.5	979.4	712.3	730.1	1891.7	4570.2	"
1954-55	"	"	"	"	"	"	3383.7	2700.6	1790.3	1727.5	1999.0	2950.5	5429.5	"
1955-56	"	"	"	"	"	"	2898.4	2200.0	1257.2	979.1	1106.2	2623.7	5938.7	"
1956-57	"	"	"	"	"	"	3115.1	2400.9	1481.4	1195.4	1394.7	2604.9	6457.0	"
1957-58	"	"	"	"	"	"	2900.7	2208.0	1286.3	1025.7	1202.9	2465.7	6070.8	"

Note: The above ORC's are limited to individual project flood control rule curves. Prior AOP's did not include the flood control limit in the Table 10 list of ORC's although it has always been limited in the hydroregulation model.

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

	1996-97	1997-98	1998-99	1999-00	2000-01
MICA TARGET OPERATION					
(ksfd[xxxx.x] or cfs [xxxxx])					
AUG 15	3456.2	3456.2	3456.2	3456.2	3486.2
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	14000	15000	11000	3428.2	3386.2
NOV	19000	19000	3256.2	3176.2	3056.2
DEC	23000	23000	2676.2	24000	25000
JAN	24000	24000	24000	25000	26000
FEB	20000	22000	22000	22000	23000
MAR	19000	19000	22000	21000	22000
APR 15	156.2	106.2	86.2	156.2	26000
APR 30	0.0	0.0	56.2	106.2	106.2
MAY	10000	10000	10000	10000	8000
JUN	10000	10000	10000	10000	8000
JUL	3356.2	3356.2	3406.2	3456.2	3456.2
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (ksfd)					
1928 AUG 31	7814.6	7814.6	7814.6	7814.6	7814.6
1928 DEC	5131.2	5755.8	6250.9	5618.4	5402.7
1929 APR15	120.3	678.7	1676.3	1763.1	1597.9
1929 JUL	6786.0	6863.4	7005.8	6916.0	7116.1
COMPOSITE 50-YR AVERAGE CANADIAN TREATY STORAGE CONTENT (ksfd)					
AUG 31	7357.3	7212.1	7323.8	7295.4	7389.8
DEC	4794.1	5224.7	5584.3	5283.1	5157.8
APR15	653.0	729.7	888.6	1424.0	1150.7
JUL	7121.9	7117.9	7110.7	7099.3	7273.7
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-2.0	-0.9	-5.1	-1.5	-0.3
U.S. Dependable Peaking Capacity	3.0	-4.0	27.0	0.0	-2.0
U.S. Average Annual Usable Secondary Energy	1.2	13.9	18.9	19.5	16.2
BCH Firm Energy	36.0	46.7	26.7	102.2	60.8
BCH Dependable Peaking Capacity	-10.0	19.0	18.0	-3.0	-36.0
BCH Average Annual Usable Secondary Energy	-36.9	-43.5	-18.5	-42.9	-43.6
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	10047	10223	10083	9793	10043
AUG 31	10055	10259	10203	9925	10125
SEP	10028	10121	9957	9630	10095
OCT	10508	10153	9963	9764	10046
NOV	11716	11452	11305	11297	11381
DEC	12738	12582	12787	12766	12836
JAN	13340	13477	13640	13725	13484
FEB	12581	12664	12638	12674	12765
MAR	12277	11948	11994	12113	11807
APR 15	13045	12643	11671	11099	11332
APR 30	14550	13437	12425	12672	13025
MAY	15720	16270	15701	17263	14347
JUN	11426	13781	14662	14699	11925
JUL	10559	10386	10594	9894	11275
ANNUAL AVERAGE	12061	12171	12117	12131	11850

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

TABLE 1M
(Metric Units)
MICA PROJECT OPERATING CRITERIA
2000-01 ASSURED OPERATING PLAN

		— Target Operation —			
Period	End of Previous Period Arrow Storage Content (hm^3)	Period Average Outflow (m^3/s)	End-of-Period Treaty Content 1/ (hm^3)	Minimum Outflow (m^3/s)	Minimum Treaty Storage Content 2/ (hm^3)
August 1-15	6361.2 - FULL	-	8529.3	424.75	0.0
	4036.9 - 6361.2	481.39			
	0.0 - 4036.9	736.24			
August 16-31	8318.4 - FULL	-	8634.5	424.75	0.0
	3547.6 - 8318.4	679.60			
	0.0 - 3547.6	764.55			
September	8465.2 - FULL	-	8634.5	283.17	0.0
	3914.6 - 8465.2	622.97			
	0.0 - 3914.6	764.55			
October	7706.8 - FULL	-	8284.7	283.17	0.0
	3180.6 - 7706.8	622.97			
	0.0 - 3180.6	792.87			
November	7511.1 - FULL	-	7477.3	339.80	0.0
	5676.1 - 7511.1	622.97			
	0.0 - 5676.1	792.87			
December	6483.5 - FULL	707.92		594.65	0.0
	4721.9 - 6483.5	764.55			
	0.0 - 4721.9	821.19			
January	5945.2 - FULL	736.24		424.75	259.8
	3107.2 - 5945.2	792.87			
	0.0 - 3107.2	849.50			
February	5015.5 - FULL	651.29		424.75	0.0
	5003.3 - 5015.5	594.65			
	0.0 - 5003.3	736.24			
March	4110.3 - FULL	622.97		424.75	0.0
	367.0 - 4110.3	764.55			
	0.0 - 367.0	0.00			
April 1-15	4428.3 - FULL	736.24		339.80	0.0
	122.3 - 4428.3	-	333.2		
	0.0 - 122.3	339.80			
April 16-30	2568.9 - FULL	-	259.8	283.17	0.0
	48.9 - 2568.9	-	0.0		
	0.0 - 48.9	283.17			
May	4514.0 - FULL	226.53		226.53	0.0
	538.3 - 4514.0	283.17			
	0.0 - 538.3	651.29			
June	5040.0 - FULL	226.53		226.53	0.0
	1076.5 - 5040.0	283.17			
	0.0 - 1076.5	481.39			
July	7768.0 - FULL	-	8455.9	226.53	0.0
	4061.4 - 7768.0	283.17			
	0.0 - 4061.4	594.65			

Notes:

1/ A maximum outflow of 962.77 m^3/s will apply if the target end-of-period storage content @ Mica is less than 8634.5 hm^3 in every month except April, May, and June. For these periods, the maximum outflow is 821.19 m^3/s in April 1-15, 764.55 m^3/s in April 16-30, 849.50 m^3/s in May and 934.46 m^3/s in June.

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

TABLE 3M
(Metric Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2000 - 01 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	8634.5	8634.5	7698.7	8071.3	7250.5	5826.6	4635.3	4648.3	3862.7	2099.7	939.2	2065.4	6095.9	8289.3
1929-30	8634.5	8612.8	7708.7	6285.1	3578.2	2744.1	1833.5	1793.4	1420.0	31.8	0.0	719.1	2263.3	5553.0
1930-31	7001.2	7214.5	7195.5	5310.6	2816.5	2540.5	2148.1	1914.2	1556.5	6.9	0.0	0.0	1997.4	4570.0
1931-32	4124.0	4410.0	3708.6	2807.5	1256.3	22.3	22.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	8757.8	8757.8	8652.6	7617.5	7413.4	6546.9	4155.8	2144.4	2368.8	1244.1	878.3	2192.4	5876.7	7420.5
1929-30	8168.0	8140.1	7864.8	8389.9	7827.7	5517.6	1887.6	2038.3	2054.4	1484.4	1311.6	1405.6	5856.2	8148.2
1930-31	8131.5	8088.0	8124.2	7855.5	7918.7	5297.4	1576.8	1360.3	1913.5	1320.4	847.3	1228.7	5348.0	5452.5
1931-32	6047.5	5003.8	4697.7	3679.2	3481.0	2950.6	1158.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	1726.8	1726.8	1685.5	1688.2	1386.2	844.8	692.4	672.8	545.1	565.7	586.2	831.8	1399.9	1700.4
1929-30	1726.8	1704.5	1511.5	1160.7	687.7	272.1	2.9	0.2	21.5	78.3	135.3	415.9	782.9	1157.2
1930-31	1318.2	1452.8	1472.4	1224.8	913.1	413.7	44.8	16.9	22.0	54.3	4.9	69.7	266.7	583.0
1931-32	587.2	489.3	415.9	391.5	3.2	19.6	2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	19119.2	19119.2	18036.8	17377.0	16050.2	13218.2	9483.5	7465.6	6776.6	3909.4	2403.8	5089.7	13372.6	17410.3
1929-30	18529.3	18457.4	17085.1	15835.6	12093.5	8533.7	3724.0	3831.9	3495.9	1594.4	1446.9	2540.5	8902.4	14858.4
1930-31	16450.9	16755.3	16792.0	14390.9	11648.3	8251.6	3769.7	3291.4	3492.0	1381.6	852.2	1298.4	7612.1	10605.5
1931-32	10758.7	9903.1	8822.2	6878.1	4740.5	2992.4	1183.2	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
2000-01 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	2324.3	3704.6	5180.7	5616.9	5776.7	5817.0	5804.3	4611.8	3339.1	2776.9	2307.6	2919.0	5867.9	8634.5
VARIABLE REFILL CURVES (hm^3)														
1928-29							7285.0	6547.3	5928.6	5620.6	5499.7	5249.7	6925.8	8634.5
1929-30							4779.7	3945.1	3300.5	3040.1	3242.2	3750.9	6230.5	-
1930-31							5414.6	4601.8	3946.9	3632.7	3664.8	3800.1	6414.5	-
1931-32							3086.1	2770.3	2661.2	2423.6	2558.9	3073.9	6122.1	-
1932-33							2852.0	2622.8	2556.0	2313.5	2335.8	2820.2	5722.4	-
1933-34							1536.7	759.2	591.6	387.3	647.1	2198.8	6340.6	-
1934-35							3990.6	3529.5	3287.0	3064.1	3056.3	3327.6	5914.4	-
1935-36							3582.3	3066.1	2742.6	2463.2	2526.6	3190.1	6548.1	-
1936-37							7256.1	6468.1	5813.1	5478.7	5476.0	5283.2	7004.9	-
1937-38							3765.1	3490.8	3382.7	3154.9	3199.4	3624.9	6346.0	-
1938-39							4935.3	4290.1	3668.7	3418.4	3505.2	3857.6	6984.1	-
1939-40							4414.2	3661.6	3082.0	2817.3	2958.2	3350.9	6396.4	-
1940-41							5859.6	5098.0	4491.2	4223.8	4455.3	4730.5	6959.6	-
1941-42							5237.2	4776.7	4472.9	4179.3	4166.8	4364.2	6720.6	-
1942-43							5320.4	4992.0	4889.8	4637.3	4799.5	5173.1	6929.3	-
1943-44							7535.8	6692.2	6071.0	5743.9	5687.9	5545.5	7344.2	-
1944-45							7208.2	6519.5	5984.4	5705.0	5603.4	5366.1	7146.0	-
1945-46							2344.1	1995.2	1881.2	1614.5	1682.8	2323.3	6108.4	-
1946-47							2634.7	2417.2	2374.4	2159.9	2278.0	2975.6	6280.9	-
1947-48							2510.0	2241.8	2161.6	1883.6	1918.9	2470.8	6003.7	-
1948-49							6659.4	6330.3	6188.2	5933.2	5891.9	5866.7	7891.3	-
1949-50							3379.5	3015.2	2877.7	2610.3	2643.8	3016.7	5542.0	-
1950-51							3358.0	3110.4	3051.4	2827.3	2926.9	3310.7	6426.5	-
1951-52							4353.0	4001.2	3880.8	3598.2	3607.5	4039.8	6786.9	-
1952-53							5040.7	4732.9	4636.6	4384.1	4327.1	4422.7	6705.9	-
1953-54							2291.0	2012.3	1973.7	1739.8	1786.3	2263.8	5473.8	-
1954-55							4149.4	3910.2	3853.2	3633.0	3653.0	3857.8	5949.4	-
1955-56							3044.8	2762.2	2653.3	2392.5	2439.5	3058.7	6217.3	-
1956-57							3457.0	3156.8	3084.2	2852.7	2893.3	3271.3	7026.1	-
1957-58							3050.4	2781.8	2724.5	2506.5	2591.4	3016.4	6445.1	-
LIMITING RULE CURVE (hm^3)							1536.7	759.2	279.6	0.0				
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVES														
	84.95	84.95	84.95	84.95	84.95	84.95	84.95	566.34	566.34	566.34	566.34	566.34	566.34	566.34
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
98.68 km^3 –							84.95	283.17	283.17	283.17	339.80	566.34	566.34	566.34
117.18 km^3 –							84.95	84.95	84.95	226.53	339.80	509.70	566.34	566.34
135.69 km^3 –							84.95	84.95	84.95	226.53	339.80	509.70	566.34	566.34

TABLE 5M
(Metric Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2000-01 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	0.0	1324.6	4810.0	5172.4	6322.3	7874.6	8005.3	6819.4	5151.8	5162.3	4916.0	6435.8	8369.8	8757.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							8757.8	8757.8	8271.2	8518.6	8757.8	8740.2	8757.8	8757.8
1929-30							6568.4	5839.5	5129.5	4899.3	5845.4	7251.5	8679.1	"
1930-31							7077.8	6236.4	5472.1	5773.0	6345.0	6847.3	8711.1	"
1931-32							4043.5	2620.3	422.5	2.7	0.0	2524.9	6776.1	"
1932-33							"	"	"	"	520.9	2791.1	6624.2	"
1933-34							"	"	"	"	543.6	3803.0	7967.1	"
1934-35							"	"	2012.6	2244.0	3074.2	4485.8	7225.3	"
1935-36							"	"	1892.0	1635.3	2133.4	4475.3	8355.9	"
1936-37							8757.8	8757.8	8757.8	8757.8	8757.8	8757.8	8757.8	"
1937-38							4043.5	2620.3	1126.4	1672.3	2761.7	4686.0	7580.5	"
1938-39							6901.1	6031.1	5173.1	5281.5	6070.0	7055.5	8757.8	"
1939-40							6252.3	5491.1	4763.3	4549.0	5517.8	6517.5	"	"
1940-41							8237.0	7861.7	7243.4	7831.3	8757.8	8757.8	"	"
1941-42							5275.4	4975.7	5130.3	5745.8	6545.6	7354.7	"	"
1942-43							4216.7	4229.9	4820.3	5636.2	6671.4	8090.2	8742.2	"
1943-44							8757.8	8757.8	8757.8	8757.8	8757.8	8757.8	8757.8	"
1944-45							"	"	8652.9	"	"	"	"	"
1945-46							4043.5	2620.3	422.5	2.7	340.1	2776.9	7127.2	"
1946-47							"	"	614.1	752.8	1426.1	3801.8	7501.8	"
1947-48							"	"	422.5	241.7	752.1	2975.6	7121.1	"
1948-49							"	3364.3	4010.7	4897.1	5874.5	7332.7	8757.8	"
1949-50							"	2620.3	422.5	190.1	1095.8	2929.8	6343.8	"
1950-51							"	"	942.2	1001.1	2208.8	4067.0	7832.5	"
1951-52							"	"	933.1	1760.6	2747.8	4937.5	8112.2	"
1952-53							"	"	2633.8	3515.8	4340.8	5625.7	7984.5	"
1953-54							"	"	422.5	2.7	0.0	2054.2	6316.4	"
1954-55							"	"	"	1314.6	2385.2	3921.7	6261.3	"
1955-56							"	"	"	2.7	387.1	3075.9	7233.6	"
1956-57							"	"	"	"	884.7	2899.0	8344.4	"
1957-58							"	"	"	"	590.1	2712.1	7517.4	"
LIMITING RULE CURVE (hm^3)							4043.5	2620.3	422.5	2.7				
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVES														
	141.58	141.58	141.58	141.58	141.58	141.58	141.58	1132.67	1132.67	1132.67	1132.67	1132.67	1274.26	1415.84
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
98.68 km^3 –							141.58	566.34	622.97	707.92	849.50	991.09	1189.31	1245.94
117.18 km^3 –							141.58	141.58	141.58	226.53	566.34	651.29	934.46	971.27
135.69 km^3 –							141.58	141.58	141.58	226.53	566.34	651.29	934.46	971.27

TABLE 6M
(Metric Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES
LIMITING RULE CURVE AND POWER DISCHARGE REQUIREMENTS
2000-01 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	279.6	453.1	615.3	690.4	733.2	760.6	785.6	712.2	640.5	621.4	602.4	880.8	1323.4	1726.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							1190.5	1105.1	1045.2	1029.5	1021.9	1095.3	1456.2	1726.8
1929-30							1186.4	1100.2	1039.6	1023.2	1049.8	1146.0	1484.1	*
1930-31							1050.8	967.6	915.5	911.8	919.9	1021.0	1456.2	*
1931-32							22.8	3.4	37.2	79.5	200.6	537.0	1226.2	*
1932-33							2.9	0.0	0.0	0.2	0.0	102.0	897.4	*
1933-34							*	21.5	68.3	125.3	312.7	684.3	1368.1	*
1934-35							358.2	330.5	345.7	362.3	411.8	667.4	1225.5	*
1935-36							275.5	227.3	210.7	218.5	272.3	603.3	1310.4	*
1936-37							1063.0	977.4	921.6	905.7	900.3	1002.4	1412.7	*
1937-38							195.7	194.3	222.9	262.5	351.8	673.8	1286.4	*
1938-39							688.7	618.7	572.0	566.1	599.7	805.2	1414.1	*
1939-40							650.3	591.3	562.5	580.1	617.0	810.3	1386.2	*
1940-41							848.7	784.1	745.5	766.0	820.6	999.7	1444.2	*
1941-42							620.7	599.2	602.8	621.7	673.1	901.6	1385.8	*
1942-43							515.7	503.3	527.5	553.9	639.1	945.4	1366.9	*
1943-44							1232.1	1157.7	1109.8	1099.3	1095.3	1176.3	1530.1	*
1944-45							1004.8	939.5	900.1	893.3	892.3	999.4	1425.9	*
1945-46							2.9	0.0	0.0	0.2	25.9	404.2	1210.1	*
1946-47							*	*	*	25.4	131.4	509.6	1241.2	*
1947-48							91.0	82.9	113.3	139.0	220.7	551.5	1266.4	*
1948-49							650.3	630.0	645.7	665.0	728.4	977.9	1515.7	*
1949-50							168.3	150.5	172.5	194.3	269.9	573.0	1129.8	*
1950-51							2.9	0.0	8.8	32.5	134.8	488.8	1205.7	*
1951-52							240.5	226.3	255.9	281.4	360.9	696.8	1316.0	*
1952-53							237.8	224.4	252.0	279.2	353.8	643.7	1233.6	*
1953-54							2.9	0.0	0.0	0.2	0.0	310.2	1064.0	*
1954-55							85.6	76.8	104.5	135.1	213.6	520.4	1073.1	*
1955-56							2.9	0.0	0.0	0.2	11.7	424.2	1200.1	*
1956-57							120.9	96.9	117.7	145.1	234.9	555.1	1357.4	*
1957-58							2.9	0.0	0.0	0.2	45.3	401.5	1239.4	*
LIMITING RULE CURVE (hm^3)							2.9	0.0	0.0	0.2				

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVES	2.83	2.83	2.83	2.83	2.83	2.83	2.83	42.48	42.48	42.48	42.48	42.48	56.63	56.63
VARIABLE REFILL CURVES (VOLUME RUNOFF AT THE DALLES)														
98.68 km^3 --							2.83	28.32	28.32	28.32	56.63	56.63	56.63	62.30
117.18 km^3 --							2.83	2.83	2.83	2.83	11.33	16.99	50.97	56.63
135.69 km^3 --							2.83	2.83	2.83	2.83	11.33	16.99	50.97	56.63

TABLE 7M
(Metric Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2000-01 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)
2000-01 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)
2000-01 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	249.8	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)
2000-01 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.2	19119.2	18036.8	17377.0	16050.2	14195.7	14114.2	12179.9	9655.0	8560.7	7825.9	10235.6	15865.7	19119.2
1929-30	"	"	"	"	"	"	12133.7	10496.9	9070.5	8297.6	7825.9	10235.6	15854.7	"
1930-31	"	"	"	"	"	"	13277.9	11545.0	9655.0	8560.7	7825.9	10235.6	15825.3	"
1931-32	"	"	"	"	"	"	7152.4	5394.0	3120.9	2505.8	2508.3	5981.0	14098.3	"
1932-33	"	"	"	"	"	"	6898.4	5243.1	2978.5	2316.4	2828.5	5713.3	13243.9	"
1933-34	"	"	"	"	"	"	5583.1	3401.0	1082.4	515.3	1501.5	6686.1	15431.2	"
1934-35	"	"	"	"	"	"	8392.3	6310.0	5459.8	5181.2	4978.8	7599.1	14333.9	"
1935-36	"	"	"	"	"	"	7901.3	5846.6	4794.8	4273.0	4713.4	7997.7	15762.2	"
1936-37	"	"	"	"	"	"	13784.9	12112.6	9655.0	8560.7	7825.9	10235.6	15803.1	"
1937-38	"	"	"	"	"	"	8004.3	6305.4	4732.0	4711.7	5361.0	7999.2	14962.9	"
1938-39	"	"	"	"	"	"	11947.2	9755.8	7933.1	7252.0	7141.6	10160.0	15865.7	"
1939-40	"	"	"	"	"	"	11316.7	9435.1	8127.6	7637.1	7592.8	10165.1	15852.0	"
1940-41	"	"	"	"	"	"	14114.2	11962.2	9509.0	8458.4	7784.6	10196.9	15749.0	"
1941-42	"	"	"	"	"	"	11133.3	9272.6	6745.3	5820.2	5613.7	8531.5	15851.5	"
1942-43	"	"	"	"	"	"	10052.8	9293.4	6766.1	5965.8	6083.0	7150.4	13308.0	"
1943-44	"	"	"	"	"	"	14114.2	12179.9	9655.0	8560.7	7825.9	10235.6	15865.7	"
1944-45	"	"	"	"	"	"	12909.2	10557.6	8529.1	7490.3	7177.1	9595.3	15685.9	"
1945-46	"	"	"	"	"	"	6390.5	4615.5	2303.7	1617.4	2048.8	5504.4	14433.2	"
1946-47	"	"	"	"	"	"	6681.2	5037.5	2988.5	2938.1	3835.5	7230.4	14838.9	"
1947-48	"	"	"	"	"	"	6644.5	4945.1	2697.4	2264.3	2831.2	5997.8	14391.1	"
1948-49	"	"	"	"	"	"	10498.1	8626.7	6943.7	6198.7	6276.5	9902.9	15865.7	"
1949-50	"	"	"	"	"	"	7591.3	5786.0	3460.5	2960.6	3563.7	6094.0	12133.4	"
1950-51	"	"	"	"	"	"	7404.4	5730.7	4002.4	3810.6	4651.2	6724.2	15134.2	"
1951-52	"	"	"	"	"	"	8637.0	6781.7	4956.1	4697.7	5220.3	7530.9	14093.6	"
1952-53	"	"	"	"	"	"	9322.0	7428.9	6489.9	5539.3	5384.5	7104.9	14703.3	"
1953-54	"	"	"	"	"	"	6337.4	4632.6	2396.2	1742.7	1786.3	4628.2	11181.5	"
1954-55	"	"	"	"	"	"	8278.6	6607.3	4380.1	4226.5	4890.8	7218.7	13283.8	"
1955-56	"	"	"	"	"	"	7091.2	5382.5	3075.9	2395.5	2706.4	6419.1	14529.6	"
1956-57	"	"	"	"	"	"	7621.4	5874.0	3624.4	2924.7	3412.3	6373.1	15797.7	"
1957-58	"	"	"	"	"	"	7096.9	5402.1	3147.1	2509.5	2943.0	6032.6	14852.8	"

Note: The above ORC's are limited to individual project flood control rule curves. Prior AOP's did not include the flood control limit in the Table 10 list of ORC's although it has always been limited in the hydroregulation model.

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

	1996-97	1997-98	1998-99	1999-00	2000-01
MICA TARGET OPERATION					
(hm^3 [xxxx.x] or m^3/s [xxxx.xx])					
AUG 15	8455.9	8455.9	8455.9	8455.9	8529.3
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	396.44	424.75	311.49	8387.4	8284.7
NOV	538.02	538.02	7966.6	7770.9	7477.3
DEC	651.29	651.29	6547.6	679.60	707.92
JAN	679.60	679.60	679.60	707.92	736.24
FEB	566.34	622.97	622.97	622.97	651.29
MAR	538.02	538.02	622.97	594.65	622.97
APR 15	382.2	259.8	210.9	382.2	736.24
APR 30	0.0	0.0	137.5	259.8	259.8
MAY	283.17	283.17	283.17	283.17	226.53
JUN	283.17	283.17	283.17	283.17	226.53
JUL	8211.3	8211.3	8333.6	8455.9	8455.9
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (hm^3)					
1928 AUG 31	19119.2	19119.2	19119.2	19119.2	19119.2
1928 DEC	12554.0	14082.1	15293.5	13746.0	13218.2
1929 APR15	294.3	1660.5	4101.2	4313.6	3909.4
1929 JUL	16602.6	16792.0	17140.4	16920.7	17410.3
COMPOSITE 50-YR AVERAGE CANADIAN TREATY STORAGE CONTENT (hm^3)					
AUG 31	18000.4	17645.1	17918.4	17848.9	18079.9
DEC	11729.2	12782.8	13662.5	12925.6	12619.1
APR15	1597.6	1785.3	2174.0	3484.0	2815.3
JUL	17424.4	17414.7	17397.0	17369.1	17795.8
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-2.0	-0.9	-5.1	-1.5	-0.3
U.S. Dependable Peaking Capacity	3.0	-4.0	27.0	0.0	-2.0
U.S. Average Annual Usable Secondary Energy	1.2	13.9	18.9	19.5	16.2
BCH Firm Energy	36.0	46.7	26.7	102.2	60.8
BCH Dependable Peaking Capacity	-10.0	19.0	18.0	-3.0	-36.0
BCH Average Annual Usable Secondary Energy	-36.9	-43.5	-18.5	-42.9	-43.6
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	10047	10223	10083	9793	10043
AUG 31	10055	10259	10203	9925	10125
SEP	10028	10121	9957	9630	10095
OCT	10508	10153	9963	9764	10046
NOV	11716	11452	11305	11297	11381
DEC	12738	12582	12787	12766	12836
JAN	13340	13477	13640	13725	13484
FEB	12581	12664	12638	12674	12765
MAR	12277	11948	11994	12113	11807
APR 15	13045	12643	11671	11099	11332
APR 30	14550	13437	12425	12672	13025
MAY	15720	16270	15701	17263	14347
JUN	11426	13781	14662	14699	11925
JUL	10559	10368	10594	9894	11275
ANNUAL AVERAGE	12061	12171	12117	12131	11850

Appendix A1
(English Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Hungry Horse (1530)	Minimum Flow	3500 cfs at Columbia Falls all months 145 cfs minimum project discharge	No change
	Maximum Flow	4500 cfs at Columbia Falls Oct 15 - Dec 15 6800 cfs June, July, and Aug for fishing	No change
	Minimum Content	1930: 1160.4 ksfd Jul, 313.4 ksfd Dec 1930: Jan-Jun (ksfd) as follows: 239.4 / 193.8 / 111.7 / 135.2 / 258.3 / 394.8 / 582.6 1931: 655.8 ksfd Jul, 239.4 ksfd Dec 1931: Jan-Jun (ksfd) as follows: 193.8 / 151.0 / 69.0 / 69.0 / 69.0 / 423.6 / 516.3 1932: 366.9 ksfd Jul	No change
	Other	85 ft draft limit for resident fish implemented as minimum VECC limit of 694.4 ksfd	No change
Kerr (1510)	Minimum Flow	3200 cfs all periods	4000 cfs Dec-Feb 12000 cfs May 16-Jun 15 (monthly ave used was 7742 cfs May and 7600 cfs June) 3200 cfs all other periods
	Maximum Flow		20000 cfs Aug, Sep, and Apr 15000 cfs Oct, Nov, Mar 18000 cfs Dec, Jan, Feb 40000 cfs May - Jun 30000 cfs July
	Minimum Content	614.7 ksfd Jun-Sep 426.3 ksfd May Empty Apr 15	No change
	Other	Conditions permitting, should be on or about 2883 ft (empty) Apr 15	No change

Appendix A1
(English Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Thompson Falls (1490)		None noted	No change
Noxon Rapids (1480)	Minimum Content	100.8 ksfd May-Sep 78.7 ksfd Oct-Apr Empty last year of CP	No change
Cabinet Gorge (1475)		None noted	No change
Albeni Falls (1465)	Minimum Flow	4000 cfs all periods	No change
	Minimum Content	559.1 ksfd Jun-Aug (582.4 at start of CP) 465.7 ksfd Sep 190.4 ksfd Oct and Apr 30 57.6 ksfd Nov-Apr 15 (empty at end of CP) 279.0 ksfd May	No change " " " 325.7 ksfd May
	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	No change
	Other spill	50 cfs all periods	No change
Box Canyon (1460)		None noted	No change

Appendix A1
(English Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Grand Coulee (1280)	Minimum Flow	30000 cfs all periods	No change
	Minimum Content	2408.3 ksfd Jun-Sep 843.9 ksfd May 289.1 ksfd except empty at end of CP	No change " Empty at end of CP 289.1 ksfd if nonfirm is produced
	Maximum Content	2 ft operating room Sep-Nov 3 ft operating room Dec-Feb	No change
	Draft limit	1.3 feet/day (bank sloughage) (Constraint submitted as 1.5 ft/day interpreted as 1.3 ft/day mo. ave.)	No change
	VECC	Minimum VECC 289.1 ksfd	No minimum VECC for Inchelium Ferry, but cannot draft below 289.1 ksfd except for firm load. 289.1 was not used as a VECC limit in the studies. May 31 min VECC 843.9 ksfd (1240 ft) Jun 30 min VECC 2408.3 ksfd (1285 ft)
Chief Joseph (1270)	Other spill	500 cfs all periods	No change
Wells (1220)	Other spill	1200 cfs all periods	No change
	Fish spill	20% of flow in May	10.2 kcfs Apr 30, May, Jul, and Aug 15
Rocky Reach (1200)	Fish Bypass	Bypass system completion 1994	Bypass not modeled (installation data set to year 2010)[1]
	Fish spill	20% of flow in May	Proportional spill was removed. There is no fish spill at this project in the studies.

[1] Bypass completion date. After this date, fish spill is discontinued.

Appendix A1
(English Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Rock Island (1170)	Fish Bypass	Bypass system completion 1994	Bypass not modeled (installation data set to year 2010) [1]
	Fish spill	20% of flow May 4229 cfs Jul 2353 cfs Aug 15 2857 cfs Jun	Proportional spill was removed. The fixed component remains. Jul: no change Aug 15: no change Jun: no change.
Wanapum (1165)	Fish Bypass	Bypass system completion 1997	Bypass not modeled (installation data set to year 2010)[1]
	Other spill	2200 cfs all periods	No change
	Fish spill	2.7% of flow Jul 5.5% of flow Aug 16.5% of flow May	Proportional spill was removed from the studies.
Priest Rapids (1160)	Minimum Flow	50000 cfs all periods except April and May 60000 cfs in Apr No limit noted in May	36000 cfs all periods
	Fish Bypass	Bypass system completion 2001	Bypass not modeled (installation data set to year 2010)[1]
	Other spill	2200 cfs all periods	No change
	Fish spill	2.6% of flow Jul 5.3% of flow Aug 18.8% of flow May	Proportional spill was removed from the studies.
Brownlee (767)	Minimum Flow	5000 cfs all periods	No change
Oxbow (765)	Other spill	100 cfs all periods	No change

Appendix A1
(English Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Ice Harbor (502)	Fish Bypass	Bypass system completion 1994	Bypass not modeled (installation data set to year 2010)[1]
	Other spill	740 cfs all periods	No change
	Incremental spill	2600 cfs Apr-Aug	No change
	Minimum Flow	9500 cfs Mar-Jul 7500 cfs Aug-Nov	No change
	Other	Run-of-river project	Data submitted for reservoir project. Run at fixed content although PNCA submittal was to run project at minimum operating pool Apr 1-Jul 31.
McNary (488)	Other spill	3475 cfs all periods	No change
	Incremental spill	525 cfs Apr 15-Sep 30	No change
John Day (440)	Fish Bypass		Bypass not modeled (installation data set to year 2010)[1]
	Other spill	800 cfs all periods	No change
	Incremental spill	100 cfs all periods	No change
	Fish spill	6% of flow Jul and Aug15 4% of flow Jun	Proportional spill removed
	Minimum Flow	50000 cfs Mar-Nov (for completeness) 12500 cfs Dec-Feb (for completeness) (not a factor in monthly studies)	No change
	Other	Note: AOP99 Steps II and III use JDA as a run-of-river plant at 262.5 ft	Feb 1-Oct 31 Run at 257 ft (empty, 0.0 ksfd) Nov 1-Jan 31 run at 265 ft (190.0 ksfd) (Note: AOP99 Steps II and Step III use JDA as a run-of-river plant run at 265 ft)

Appendix A1
(English Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
The Dalles (365)	Fish Bypass	Bypass system completion 1998	Bypass not modeled (installation data set to year 2010)[1]
	Other spill	1300 cfs all periods	No change
	Incremental spill	2700 cfs Apr-Oct 1200 cfs Nov	No change
	Fish spill		Proportional spill removed.
	Minimum Flow	50000 cfs Mar-Nov (for completeness) 12500 cfs Dec-Feb (for completeness) (not a factor in monthly studies)	No change
Bonneville (320)	Fish Bypass	Bypass system completion 1996	Bypass not modeled (installation data set to year 2010) [1]
	Other spill	8040 cfs all periods	No change
	Incremental spill	360 cfs Mar-Nov	No change
	Fish spill		Proportional spill removed
Kootenay Lake (1665)	Minimum Flow	5000 cfs all periods	No change
Chelan (1210)	Minimum Flow	50 cfs all periods	No change
	Minimum Content	308.5 ksfd Jun-Sep (except as needed to empty at end of critical period)	June - Sep: no change 95.9 ksfd Apr 30 (except as needed to empty at end of critical period)
Couer d'Alene L. (1341)	Minimum Flow	300 cfs all periods	No change
	Minimum Content	112.5 ksfd May-Aug	No change

Appendix A1
(English Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Libby (1760)	Minimum flow	4000 cfs all periods	No change
	Other spill		200 cfs all periods (Not new)
	Minimum content (ksfd)	1929: 777.0 Dec, 676.6 Jan, 604.0 Feb.	1929: 776.9 Dec, 676.5 Jan, 603.6 Feb, 2147.7 Jul.
		1930: 2156.1 Jul, 652.1 Dec, 513.6 Jan 502.3 Feb-May, 1351.1 Jun.	1930: 652.0 Dec, 433.2 Jan, 389.3 Feb, 348.5 Mar, 297.4 Apr 15, 444.2 Apr 30, 499.1 May, 1344.6 Jun, 1771.9 Jul.
		1931: 1777.2 Jul, 423.2 Dec, 290.8 Jan, 192.3 Feb-Apr, 261.3 May, 803.0 Jun.	1931: 317.8 Dec, 192.2 Jan, 103.1 Feb-Apr 30 , 192.2 May, 676.5 Jun, 868.0 Jul.
		1932: 1010.3 Jul, 175.6 Dec, 108.7 Jan.	1932: 174.4 Dec, 103.1 Jan, empty at end of CP.
			(Note: Requirements as reflected in data submittal 2-1-94, used in AOP00: All Dec: 776.9 ksfd Jul 1930: No more than 373.1 ksfd lower than Jul 1929 Jul 1931: No more than 857.1 ksfd lower than Jul 1930) Mar: Implement PNCA 6(c)2(c)
	Maximum summer draft	10 ft	5 ft
	Other	Operate to meet IJC rules for Corra Linn	No change

Appendix A1
(English Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Dworshak (535)	Minimum flow	2000 cfs all periods except Apr and Aug 1000 cfs Aug 10000 cfs May	8800 cfs Apr 30, May, and Jul 6300 cfs Jun 1200 cfs all other periods
	Maximum flow	Inflow plus 1300 cfs Oct 1-Nov 15 25000 cfs all other periods (local flooding)	No change
	Other		Run on minimum flow or flood control observing maximum and minimum flow requirements all periods except Aug 1. Aug 1 try to meet LWG target of 50000 cfs, but draft no lower that 1520 ft. Use 1490.2 ft (218.4 ksfd) for end of critical period.
Lower Granite (520)	Bypass Date		None
	Other spill		670 cfs all periods
	Incremental spill		250 cfs Apr 15-Aug 31
	Fish spill		13.2% Apr 15 40% Apr 30 and May 27% Jun Maximum spill: 60000 cfs
	Minimum flow		11500 cfs Mar-Nov
	Other	Modeled as Run of River	Run at 733 ft (MOP) Apr 15 - Oct. Run at 738 ft all other periods

Appendix A1
(English Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Little Goose (518)	Bypass date		None
	Other spill		630 cfs all periods
	Incremental spill		250 cfs Apr 15-Aug 31
	Fish spill		13.2% Apr 15 40% Apr 30 and May 27% Jun
	Maximum spill		30000 cfs
	Minimum flow		11500 cfs Mar-Nov
	Other	Modeled as Run of River	Run at 633 ft (Apr 15-Aug 31) Run at 638 ft all other periods
Lower Monumental (504)	Bypass Date		A bypass date of 2010 was assumed.
	Other spill		750 cfs all periods
	Fish spill		13.4% Apr 15 40.5% Apr 30 and May 27.1% Jun
	Maximum spill		30000 cfs
	Minimum flow		11500 cfs Mar-Nov
	Other	Modeled as Run of River	Run at 537 ft Apr 15-Aug 31 Run at 540 ft all other periods

Appendix A2
(Metric Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Hungry Horse (1530)	Minimum Flow	99.11 m^3/s at Columbia Falls all months 4.11 m^3/s minimum project discharge	No change
	Maximum Flow	127.43 m^3/s at Columbia Falls Oct 15-Dec 15 192.55 m^3/s June, July and Aug. for fishing	No change
	Minimum Content	1930: 2839.0 hm^3 Jul, 766.8 hm^3 Dec 1930: Jan - Jun (hm^3) as follows: 585.7/ 474.2 / 273.3 / 330.8 / 632.0 / 965.9 / 1425.4 1931: 1,604.5 hm^3 Jul, 585.7 hm^3 Dec 1931: Jan - Jun (hm^3) as follows: 474.2 / 369.4 / 168.8 / 168.8 / 168.8 / 1036.4 / 1263.2 1932: 897.7 hm^3 Jul	No change
	Other	25.91 m draft limit for resident fish implemented as minimum VECC limit of 1,698.9 hm^3	No change
Kerr (1510)	Minimum Flow	90.61 m^3/s all periods	113.27 m^3/s Dec-Feb 339.80 m^3/s May 16-Jun 15 (monthly ave used was 219.23 m^3/s May and 215.21 m^3/s June) 90.61 m^3/s all other periods
	Maximum Flow		566.34 m^3/s Aug, Sep, and Apr 424.75 m^3/s Oct, Nov, Mar 509.70 m^3/s Dec, Jan, Feb 1132.67 m^3/s May - Jun 849.50 m^3/s July
	Minimum Content	1503.9 hm^3 Jun - Sep 1043.0 hm^3 May Empty Apr 15	No change
	Other	Conditions permitting, should be on or about 878.74 m (empty) Apr 15	No change

Appendix A2
(Metric Units)
Project Operating Procedures for the 1997-98 & 2000-01
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	Constraint	Requirement 1997-98	Requirement 2000-01
Thompson Falls (1490)		None noted	No change
Noxon Rapids (1480)	Minimum Content	246.6 hm^3 May - Sep 192.6 hm^3 Oct - Apr Empty last year of CP	No change
Cabinet Gorge (1475)		None noted	No change
Albeni Falls (1465)	Minimum Flow	113.27 m^3/s all periods	No change
	Minimum Content	1367.9 hm^3 Jun-Aug (1424.9 at start of CP) 1139.4 hm^3 Sep 465.8 hm^3 Oct and Apr 30 140.9 hm^3 Nov-Apr 15 (empty at end of CP) 682.6 hm^3 May	No change " " " 796.9 hm^3 May
	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	No change
	Other spill	1.42 m^3/s all periods	No change
Box Canyon (1460)		None noted	No change

Appendix A2
(Metric Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Grand Coulee (1280)	Minimum Flow	849.50 m^3/s all periods	No change
	Minimum Content	5892.1 hm^3 Jun-Sep 2064.7 hm^3 May 707.3 hm^3 except empty at end of CP	No change " Empty at end of CP 707.3 hm^3 if nonfirm is produced
	Maximum Content	0.61 m operating room Sep-Nov 0.91 m operating room Dec-Feb	No change
	Draft limit	0.40 m/day (bank sloughage) (Constraint submitted as 0.46 m/day interpreted as 0.40 m/day mo. ave.)	No change
	VECC	Minimum VECC 707.3 hm^3.	No minimum VECC for Inchelium Ferry, but cannot draft below 707.3 hm^3 except for firm load. 707.3 hm^3 was not used as a VECC limit in the studies. May 31 min VECC 2064.7 hm^3 (377.95 m) Jun 30 min VECC 5892.1 hm^3 (391.67 m)
Chief Joseph (1270)	Other spill	14.16 m^3/s all periods	No change
Wells (1220)	Other spill	33.98 m^3/s all periods	No change
	Fish spill	20% of flow in May	288.83 m^3/s Apr 30, May, Jul, and Aug 15
Rocky Reach (1200)	Fish Bypass	Bypass system completion 1994	Bypass not modeled (installation data set to year 2010)[1]
	Fish spill	20% of flow in May	Proportional spill was removed. There is no fish spill at this project in the studies.

[1] Bypass completion date. After this date, fish spill is discontinued.

Appendix A2
(Metric Units)
Project Operating Procedures for the 1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Rock Island (1170)	Fish Bypass	Bypass system completion 1994	Bypass not modeled (installation data set to year 2010)[1]
	Fish spill	20% of flow May 119.75 m^3/s Jul 66.63 m^3/s Aug 15 80.90 m^3/s Jun	Proportional spill was removed. The fixed component remains. Jul: no change Aug15: no change Jun: no change
Wanapum (1165)	Fish Bypass	Bypass system completion 1997	Bypass not modeled (installation data set to year 2010)[1]
	Other spill	62.30 m^3/s in all periods	No change
	Fish spill	2.7% of flow Jul 5.5% of flow Aug 16.5% of flow May	Proportional spill was removed from the studies
Priest Rapids (1160)	Minimum Flow	1415.84 m^3/s all periods except Apr and May 1699.01 m^3/s in Apr No limit noted in May	1019.41 m^3/s all periods
	Fish Bypass	Bypass system completion 2001	Bypass not modeled (installation data set to year 2010)[1]
	Other spill	62.30 m^3/s all periods	No change
	Fish spill	2.6% of flow Jul 5.3% of flow Aug 18.8% of flow May	Proportional spill was removed from the studies.
Brownlee (767)	Minimum Flow	141.58 m^3/s all periods	No change
Oxbow (765)	Other spill	2.83 m^3/s all periods	No change

Appendix A2
(Metric Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Ice Harbor (502)	Fish Bypass	Bypass system completion 1994	Bypass not modeled (installation data set to year 2010) [1]
	Other spill	20.95 m^3/s all periods	No change
	Incremental spill	73.62 m^3/s Apr - Aug	No change
	Minimum Flow	269.01 m^3/s Mar-Jul 212.38 m^3/s Aug-Nov	No change
	Other	Run-of-river project	Data submitted for reservoir project. Run at fixed content although PNCA submittal was to run project at minimum operating pool Apr 1-Jul 31.
McNary (488)	Other spill	98.40 m^3/s all periods	No change
	Incremental spill	14.87 m^3/s Apr 15-Sep 30	No change
John Day (440)	Fish Bypass		Bypass not modeled (installation data set to year 2010) [1]
	Other spill	22.65 m^3/s all periods	No change
	Incremental spill	2.83 m^3/s all periods	No change
	Fish spill	6% of flow Jul and Aug15 4% of flow Jun	Proportional spill removed
	Minimum Flow	1415.84 m^3/s Mar-Nov (for completeness) 353.96 m^3/s Dec-Feb (for completeness) (not a factor in monthly studies)	No change
	Other	Note: AOP99 Steps II and III use JDA as a run-of-river plant at 80.01 m	Feb 1-Oct 31 Run at 78.33 m (empty, 0.0 hm^3) Nov 1-Jan 31 run at 80.77 m (464.9 hm^3) (Note: AOP99 Steps II and III use JDA as a run-of-river plant run at 80.77 m)

Appendix A2
(Metric Units)
Project Operating Procedures for the 1997-98 & 2000-01
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	Constraint	Requirement 1997-98	Requirement 2000-01
The Dalles (365)	Fish Bypass	Bypass system completion 1998	Bypass not modeled (installation data set to year 2010) [1]
	Other spill	36.81 m^3/s all periods	No change
	Incremental spill	76.46 m^3/s Apr-Oct 33.98 m^3/s Nov	No change
	Fish spill		Proportional spill removed.
	Minimum Flow	1415.84 m^3/s Mar-Nov (for completeness) 353.96 m^3/s Dec-Feb (for completeness) (not a factor in monthly studies)	No change
Bonneville (320)	Fish Bypass	Bypass system completion 1996	Bypass not modeled (installation data set to year 2010) [1]
	Other spill	227.67 m^3/s all periods	No change
	Incremental spill	10.19 m^3/s Mar - Nov	No change
	Fish spill		Proportional spill removed
Kootenay Lake (1665)	Minimum Flow	141.58 m^3/s all periods	No change
Chelan (1210)	Minimum Flow	1.42 m^3/s all periods	No change
	Minimum Content	754.8 hm^3 Jun-Sep (except as needed to empty at end of critical period)	June - Sep: no change 234.6 hm^3 Apr 30 (except as needed to empty at end of critical period)
Couer d'Alene L. (1341)	Minimum Flow	8.50 m^3/s all periods	No change
	Minimum Content	275.2 hm^3 May-Aug	No change

Appendix A2
(Metric Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Libby (1760)	Minimum flow	113.27 m^3/s all periods	No change
	Other spill		5.66 m^3/s all periods (Not new)
	Minimum content (hm^3)	1929: 1901.0 Dec, 1655.4 Jan, 1477.7 Feb.	1929: 1900.8 Dec, 1655.1 Jan, 1476.8 Feb, 5254.6 Jul.
		1930: 5275.1 Jul, 1595.4 Dec, 1256.6 Jan, 1228.9 Feb-May, 3305.6 Jun.	1930: 1595.2 Dec, 1059.9 Jan, 952.5 Feb, 852.6 Mar, 727.6 Apr 15, 1086.8 Apr 30, 1221.1 May, 3289.7 Jun, 4335.1 Jul.
		1931: 4348.1 Jul, 1035.4 Dec, 711.5 Jan, 470.5 Feb-Apr, 639.3 May, 1964.6 Jun.	1931: 777.5 Dec, 470.2 Jan, 252.2 Feb-Apr 30, 470.2 May, 1655.1 Jun, 2123.6 Jul.
		1932: 2471.8 Jul, 429.6 Dec, 265.9 Jan.	1932: 426.7 Dec, 252.2 Jan, empty at end of CP
			(Note: Requirements as reflected in data submittal 2-1-94, used in AOP00: All Dec: 1900.8 hm^3 Jul 1930: No more than 912.8 hm^3 lower than Jul 1929 Jul 1931: No more than 2097.0 hm^3 lower than Jul 1930) Mar: Implement PNCA 6(c)2(c)
	Maximum summer draft	3.05 m	1.52 m
	Other	Operate to meet IJC rules for Corra Linn	No change

Appendix A2
(Metric Units)
Project Operating Procedures for the 1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Dworshak (535)	Minimum flow	56.63 m^3/s all periods except Apr and Aug 28.32 m^3/s Aug 283.17 m^3/s May	249.19 m^3/s Apr 30, May, & Jul 178.40 m^3/s Jun. 33.98 m^3/s all other periods
	Maximum flow	Inflow plus 36.81 m^3/s Oct 1-Nov 15 707.92 m^3/s all other periods (local flooding)	No change
	Other		Run on minimum flow or flood control observing maximum and minimum flow requirements all periods except Aug1. Aug 1 try to meet LWG target of 1415.84 m^3/s, but draft no lower that 463.30 m. Use 454.21 m (534.34 hm^3) for end of critical period.
Lower Granite (520)	Bypass Date		None
	Other spill		18.97 m^3/s all periods
	Incremental spill		7.08 m^3/s Apr 15-Aug 31
	Fish spill		13.2% Apr 15 40% Apr 30 and May 27% Jun Maximum spill: 1699.01 m^3/s
	Minimum flow		325.64 m^3/s Mar-Nov
	Other	Modeled as Run of River	Run at 223.42 m (MOP) Apr 15-Oct. Run at 224.94 m all other periods

Appendix A2
(Metric Units)
Project Operating Procedures
1997-98 & 2000-01 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	Constraint	Requirement 1997-98	Requirement 2000-01
Little Goose (518)	Bypass date		None
	Other spill		17.84 m^3/s all periods
	Incremental spill		7.08 m^3/s Apr 15-Aug 31
	Fish spill		13.2% Apr15 40% Apr 30 and May 27% Jun
	Maximum spill		849.50 m^3/s
	Minimum flow		325.64 m^3/s Mar-Nov
	Other	Modeled as Run of River	Run at 192.94 m Apr 15-Aug 31 Run at 194.46 m all other periods
Lower Monumental (504)	Bypass Date		A bypass date of 2010 was assumed.
	Other spill		21.24 m^3/s all periods
	Fish spill		13.4% Apr 15 40.5% Apr 30 and May 27.1% Jun
	Maximum spill		849.50 m^3/s
	Minimum flow		325.64 m^3/s Mar-Nov
	Other	Modeled as Run of River	Run at 163.68 m Apr 15-Aug 31 Run at 164.59 m all other periods

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 2000-01

TABLE OF CONTENTS

Section **Page**

DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB) FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2000-01

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 2000-01 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 Entity Agreement on the 1998/99, 1999/2000, and 2000/2001 Assured Operating Plan and Determination of Downstream Power Benefit Studies," dated 5 April 1995;
- The "Columbia River Treaty Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans" (POP), dated December 1991; and
- The Entity Agreements, signed 28 July and 12 August 1988, on Principles and on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies (1988 Entity Agreements).

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

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

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

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

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

As part of the DDPB for the operating year 2000-01, separate determinations were carried out relating to the limit of year-to-year change in benefits attributable to the operation of Canadian Treaty storage in operating plans designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States of America (Joint Optimum).

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

2. Results of Canadian Entitlement Computations

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

Dependable Capacity	=	1447.3 MW
Average Annual Usable Energy	=	508.4 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 2000-01 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 1999-00 Step II Joint Optimum study and Step III study.

Y = One-half of the downstream power benefits derived from the difference between the 1999-00 Step II U.S. Optimum study and Step III study.

Z = One-half of the downstream power benefits derived from the difference between the 2000-01 Step II U.S. Optimum study with 15 Maf (18.50 km^3) of Canadian storage and the Step III study.

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

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

The quantities X and Y were computed in the 1999-00 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	= 1461.9 - (1461.7 - 1427.5) = 1427.7 MW
Average Annual Usable Energy	= 559.5 - (560.3 - 502.3) = 501.5 aMW

The computed Canadian Entitlement exceeds these amounts.

4. Effect on Sale of Canadian Entitlement

The Canadian Entitlement to downstream power benefits was purchased by the Columbia Storage Power Exchange (CSPE) pursuant to the Canadian Entitlement Purchase Agreement (CEPA) dated 13 August 1964 for a period of thirty years following the completion of each Canadian storage project. The purchase of the Canadian Entitlement expired 31 March 1998 for Duncan, 31 March 1999 for Arrow, and will expire 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 2000-01 AOP for this condition was:

Dependable Capacity	= 1447.3 MW
Average Annual Usable Energy	= 507.7 aMW

Because the 2000-01 AOP was designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States of America, Section 7 of the Agreement requires that "any reduction in the Canadian Entitlement resulting from action taken pursuant to paragraph 7 of Annex A of the Treaty shall be determined in accordance with Subsection (3) of Section 6 of this Agreement." A comparison of the Canadian Entitlement for optimum power in Canada and the United States with the Canadian Entitlement to downstream power benefits shown above indicates an <u>increase</u> in the energy Entitlement of 0.7 aMW and <u>no change</u> in the capacity.

Since the sale of the downstream power benefits attributable to Duncan and Arrow expires 31 March 1998 and 31 March 1999 respectively, the United States Entity is entitled to that portion of the decrease in the Canadian Entitlement attributed to Mica. Because there was no decrease in Canadian Entitlement, the United States Entity is not entitled to any compensation attributed to the re-operation of Mica. Accordingly, the Entities are agreed that the United States Entity is not entitled to receive any energy or dependable capacity during the period 1 April 2000 through 31 March 2001, from B.C. Hydro & Power Authority, in accordance with Sections 7 and 10 of the CEPA.

5. Canadian Entitlement Return

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

The storage volume in Duncan is 1.4 Maf (1.73 km^3), in Arrow is 7.1 Maf (8.76 km^3), and the whole of Canadian storage is 15.5 Maf (19.12 km^3). Therefore, the obligation of the United States to deliver Canadian Entitlement to Canada for operating year 2000-01 beginning 1 August 2000 and ending 31 July 2001, based on the Joint Optimum power studies for benefits attributable to Duncan and Arrow is computed below. There is a 2.5 aMW adjustment to the 2000-01 Energy Entitlement according to item 7 of the "Columbia River Treaty Entity Agreement on the 1998/99, 1999/00, and 2000/2001 Assured Operating Plan and Determination of Downstream Power Benefit Studies," dated 5 April 1995.

a) Energy Entitlement Returned
Average Annual Usable Energy =
(508.4-2.5) aMW * (8.5 Maf/15.5 Maf) = 277.4 aMW
(508.4 -2.5) aMW * (10.48 km^3 /19.12 km^3)= 277.4 aMW

b) Capacity Entitlement Returned
Dependable Capacity =
1447.3 MW * (8.5 Maf/15.5 Maf) = 793.7 MW
1447.3 MW * (10.48 km^3/19.12 km^3) = 793.7 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 as defined by Treaty Annex B, paragraph 7, and clarified by the 1988 Entity Agreements. Table 1A shows the Step I energy loads and resources while Table 1B shows the Step I peak loads and resources.

Table 2. Determination of Thermal Displacement Market:

This table shows the computation of the thermal displacement market for the downstream power benefit determination of average annual usable energy. The thermal displacement market was limited to the existing and scheduled thermal energy capability including thermal imports after allowance for energy reserves, minimum thermal generation, and reductions for the thermal resources used outside the Pacific Northwest Area (PNWA). The computation of Step I thermal installations is shown in Table 1A.

Table 3. Determination of Loads for 2000-01 Step II and Step III Studies:

This table shows the computation of the Step II and III loads. The monthly loads for Step II and III studies have the same ratio between each month and the annual average as does the PNWA load. The PNWA firm loads on this table were based on the BPA 1994 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 2000-01 Assured Operating Plan:

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

Table 5. Computation of Canadian Entitlement for 2000-01 Assured Operating Plan:

A. Optimum Generation in Canada and the U.S.
B. Optimum Generation in the U.S. Only
C. Optimum Generation in the U.S. and a 0.5 Million Acre-Feet ($0.62\ km^3$) Reduction in Total Canadian Treaty Storage

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

Table 6. Comparison of Recent DDPB Studies

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

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

7. Summary of Changes from Previous Year

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

(a) Loads and Non-Hydro Resources

Loads for the 2000-01 AOP were based on the 1994 Whitebook medium case forecast developed by BPA in September 1994. Compared to the previous AOP, the PNWA firm energy load increased by 290 aMW. The total exports, not including firm surplus energy, decreased by 136 aMW. The decrease in exports is mainly due to the decreased Canadian Entitlement Return. It was assumed that 1/3 of the Entitlement Return was used to meet load in the PNWA, with the remaining amount assumed to be used in B.C. or California. The surplus firm energy increased by 32 aMW and was shaped to meet load over the year as 471 aMW 1 August through 30 April, and 1537 aMW in May through July.

The estimated increase in the Step I load due to the Canadian Entitlement Return exported to Canada assumed in the studies, and the computed Canadian Entitlement Return attributed to Duncan and Arrow for the period 1 August 2000 through 31 July 2001, are shown below for the Joint Optimum studies:

	Energy Entitlement Returned (aMW)		**Capacity Returned (MW)**	
	Estimated	Computed	Estimated	Computed
1 August 2000 to 31 July 2001	306.8	277.4	700.1	793.7

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.

The total annual energy capability of the thermal installations increased by 500 aMW. Major thermal resource changes included:

- Decrease of 10 aMW due to the termination of two Small Thermal projects: EWEB's Willamette Steam Plant and Puget's Shuffleton;
- Combustion Turbine resource increases of 285 aMW due to the addition of Clark County's new Cogentrix and Washington Water Power's Rathdrum now reporting energy;

- Cogeneration increased 99 aMW due to an increase in PP&L miscellaneous cogeneration and facilities upgrade at PGE's Coyote Springs;
- Centralia (large thermal generation) increased by 58 aMW;
- Thermal Non-Utility Generation (NUG) decreased by 20 aMW mostly due to the termination of Idaho's NUG's; and
- Imports increased by 87 aMW due to the addition of five new BPA imports and to the Glendale to PGE Seasonal Exchange. PG&E-to-WWP was the only import to terminate. Both the PP&L (WYM) to PP&L and Montana Thermal Import increased and showed different monthly shaping from the previous year's data.

(b) Operating Procedures

The 1990 level modified base flows with Grand Coulee pumping adjustments and return flows were again used. There were no additional depletions for the 2001 level, based on the recommendation of the Columbia River Water Management Group.

The Entities completed Step II and Step III Refill Studies and incorporated the resulting Power Discharge Requirements (PDR's) in the 2000-01 DDPB. New Limiting Rule Curves (LRC's) were developed for the Step II system based on 1937 water conditions. These studies are consistent with PNCA procedures, which include starting the system full 1 August 1936 and increasing the August through December load until the system just empties on 30 April 1937. The end--of-period contents in January, February, March, and 15 April are the LRC's for all major reservoir projects. Since the Step III study itself is a "LRC type" study, the LRC's are simply the end storages from the study.

Plant data for Arrow, Ice Harbor, Rock Island, and Chief Joseph were revised. However, Arrow, and Rock Island were the only projects to show a significant change in generation. Arrow had generation for the first time, and the Rock Island generation decreased due to updated information on turbine/generation efficiency.

Notable changes in non-power constraints include a revision of last year's spill data, and fisheries requirements (see Appendixes A1 and A2).

The spill and bypass assumptions for the 2000-01 DDPB studies are different from the 1999-00 DDPB studies, for operating year 2000-01 as follows:

- Fish bypass installations previously forecast to be installed at Bonneville, The Dalles, John Day, Ice Harbor, Wanapum, Rock Island, and Rocky Reach in the 1999-00 DDBP studies were removed from the hydroregulation model; and

- The Entities' 5 April 1995 agreement required the removal of the proportional fish spill and the bypass facilities from the studies, and in return the U.S. Entity would deliver the Entitlement Energy as calculated less 2.5 aMW. Most projects showed a decrease in generation. The only fish spill remaining was fixed fish spill at Wells and Rock Island. Ice Harbor and The Dalles had increased other spill. Priest Rapids was the only project to show increased generation because in the prior study bypass facilities were assumed to be installed and fish spill was modeled.

(c) Step III Critical Streamflow Period

The Step III study critical streamflow period was determined using the results of the Draft for Power method. This resulted in a 7-month critical period, 1 October 1936 through 30 April 1937 with 36 MW surplus in October 1937. If the Discretionary Draft method had been used the critical period would be 6 months, 1 November 1936 through 30 April 1937.

(d) Downstream Power Benefits Computation

The Capacity Entitlement decreased from 1461.9 MW in the 1999-00 DDPB to 1447.3 MW in the 2000-01 DDPB for a reduction of 14.6 MW. This was a result of a larger decrease in the Step II average critical period generation than in the Step III study. The 47.5 aMW decrease in the Step II critical period average generation was caused by increased spill, a plant data change at Rock Island, and the operation of Grand Coulee to the March ARC of empty in the second year of the critical period.

The Step III average critical period generation decreased by 19.2 MW compared to the 1999-00 DDPB due to increased spill, the Rock Island plant data change, and the start of the Step III critical stream flow period changed from November to October. Therefore, the difference between the Step II and Step III average critical period generation decreased by 28.3 aMW resulting in a decrease in the Capacity Entitlement.

The Canadian Energy Entitlement decreased from 559.5 aMW in the 1999-00 DDPB to 508.4 aMW in the 2000-01 DDPB, a decrease of 51.1 aMW. The following parameters were identified as having the most significant impact. Each value shown is a rough **estimate** of the incremental impact on the Energy Entitlement based on the AOP01 Step II and III studies with the AOP00 data for that parameter. Analysis of combinations of these parameters would likely produce different estimates of incremental impacts because the parameters are interrelated. For example, updated PDR's are required due to changes in other parameters, especially load shape.

Energy Entitlement

Parameter	(aMW)
Thermal Displacement Market Impact	-26
Load Shape Impact	- 8
Plant data & Spill Updates	- 7
Step II Coulee 6(c)(2)(C)	- 1
Coulee Adjusted Operating Rule Curves (ORC's)	+ 5
Updated Flood Control	+ 2
Combination of above effect on ORC's	-13
Re-operation of Canadian Storage	- 3
Total	-51

Thermal Displacement Market
The thermal displacement market increased approximately 690 aMW in the AOP01 compared to the AOP00. Major changes include an increase in thermal installations of 500 aMW, a decrease in minimum generation of 210 aMW, and an increase of approximately 20 aMW in the total system sales.

Load Shape
The change in annual energy load shape of the PNWA also caused a decrease in the Energy Entitlement. When compared to the AOP00, the Annual Energy Load Shape Percent for the Step I AOP01 increased August through October, decreased November through April, and increased May through July (See Table 3). Examination of this data for the four previous AOP's indicated that the load in the November through March period generally increased more rapidly than in other months.

Since the Step II system has a multi-year critical period, the change in load shape had virtually no impact on the study results. In the Step III system, the change in load shape and change in thermal installation caused the annual firm hydro energy to increase approximately 120 aMW. The load shape showed increases from April to October, but decreases or small changes from November to March. A flatter load shape combined with the concurrent changes in the secondary produced in the Step III long-term study (30-year) caused the Energy Entitlement to decrease approximately 8 aMW.

Plant Data & Spill Requirements
The Step II and III system annual average usable energy lost 30 aMW and 22 aMW, respectively; in generation due to updated information on turbine/generation efficiency curves (H/K data) at Rock Island. Other changes occurred due to removal of proportional spill and deferment of fish bypass facilities. The lost energy capability caused a decrease in the Energy Entitlement of approximately 4 aMW due to the Rock Island change and a decrease of 3 aMW due to spill changes and bypass dates.

Step II Grand Coulee 6(c)(2)(C)
Consistent with the PNCA 6(c)(2)(C) in the second year of the Step II critical period, Grand Coulee was drafted to its March ARC of empty, as other projects had reached or were below their March ARC's.

Grand Coulee ORC
The Inchelium ferry constraint at Grand Coulee limited draft below 289.1 thousand second-foot-days (ksfd) (707.3 cubic hectometers (hm^3)) (1220 feet) (371.86 meters) except to meet firm load. This required modifications to the ORC that increased the Energy Entitlement approximately 5 aMW.

Updated Flood Control
The Corps of Engineers submitted flood control in February 1995 which reflected flood control storage of 4.08 Maf (5.03 km^3) at Mica and 3.6 Maf (4.44 km^3) at Arrow. The Canadian Entity requested an exchange of flood control between Mica and Arrow which was used in previous AOP's. This split is based on flood control storage of 2.08 Maf (2.57 km^3) at Mica and 5.1 Maf (6.29 km^3) at Arrow. In July 1996 the Corps of Engineers provided new flood control reflecting the 2.08/5.1 Maf (2.57/6.29 km^3) split between Mica and Arrow. This flood control was used in the final AOP study.

Other changes include a new storage reservation diagram at Hungry Horse, dated 19 December 1995, which incorporated winter flood control in October and November. At Libby, there was some slight change in the percentage of refill during April and May. At Grand Coulee the flood control is dependent on available upstream storage and reflects the changes to other projects upstream. This change at Grand Coulee, along with some minor adjustments to the percentage of refill in April through June, describes the differences from the previous flood control used.

Effect on Determination of ORC's
Refill Studies were completed for the Step I, II, and III Studies to determine the ORC's. PDR's and LRC's change from year-to-year mainly due to changes in load shape, thermal resource generation shape, nonpower requirements including flood control, and irrigation depletions.

The Step II study PDR's were generally lower for the Variable Refill Curves (VRC's), but higher for the Assured Refill Curves (ARC's) when compared to the previous year's results. The ARC's generally controlled the computation of the ORC's and, since ORC's were higher, the projects were held higher longer throughout the year. More water was available to refill sooner, resulting in less ability to store, and increased spill. The Grand Coulee VRC was much lower in January through March, but higher in April. There were small changes at Horse, Duncan, Arrow, and Mica VRC's.

There was very little change from the previous year's PDR results in the Step III study. With only Base System storage available, the Step III system is difficult to refill and Hungry Horse was often on minimum flow due to requirements at Columbia Falls. The Grand Coulee VECC showed a significant change in March through April because of the 1220-ft (371.86 m) limit. There were minor changes to Chelan and Hungry Horse VECC's.

Re-operation for Joint Optimum

A comparison of the Canadian Entitlement for the Joint Optimum with the Canadian Entitlement for the U.S. Optimum showed an increase of 0.7 aMW of energy, and no change in the dependable capacity.

TABLE 1A
2000-01 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 Mon)
1. Pacific Northwest Area (PNWA) Load	19741	19663	19199	19894	21871	23492	24161	23089	21701	20470	20567	19943	19829	19992	21107.8	21228.4
a) Annual Load Shape in Percent	93.52	93.15	90.96	94.25	103.61	111.30	114.47	109.38	102.81	96.98	97.44	94.48	93.94	94.71	100.0	100.6
2. Flows-Out of firm power from PNWA																
a) Firm Exports 3/	1268	1268	1285	990	959	959	933	908	946	948	984	968	1315	1301	1067.1	1058.3
b) Exclude Plant Sales	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-40	-71	-102	-94.2	-95.3
c) Firm Surplus	471	471	471	471	471	471	471	471	471	471	471	1537	1537	1537	739.7	701.4
d) ...Total	1637	1637	1654	1359	1328	1328	1302	1277	1315	1317	1353	2465	2781	2736	1712.6	1664.4
3. Load served by Flows-In of firm power except Step I thermal installations																
a) Non-thermal firm imports	-20	-20	-15	-21	-36	-47	-60	-69	-61	-29	-29	-28	-38	-26	-37.3	-37.8
b) Seasonal Exchange Imports	0	0	0	0	-280	-286	-286	-286	-30	-6	-6	0	0	0	-96.6	-109.8
c) ...Total	-20	-20	-15	-21	-316	-333	-346	-355	-91	-35	-35	-28	-38	-26	-133.9	-147.6
4. Load served by non-Step I resources located within the PNWA																
a) Hydro Independents (1929 water)	-1265	-1205	-1070	-1134	-1157	-1051	-1092	-818	-962	-1274	-1331	-1794	-1604	-1282	-1210.7	-1063.3
b) Non-Step I Coordinated Hydro (1929 water)	-544	-475	-576	-966	-964	-1074	-1215	-690	-772	-760	-728	-656	-1084	-589	-820.8	-854.8
c) Non-Thermal PURPA/NUGS	-175	-175	-164	-156	-154	-150	-148	-152	-156	-172	-171	-179	-171	-178	-162.9	-161.6
d) Miscellaneous Resources	-38	-38	-41	-45	-51	-55	-55	-52	-50	-48	-48	-45	-44	-39	-46.9	-47.3
e) ...Total (1929 water)	-2022	-1893	-1851	-2301	-2326	-2331	-2510	-1712	-1940	-2254	-2277	-2674	-2903	-2088	-2241.3	-2127.1
5. Total Step I System Firm Loads (1929 water)	19336	19386	18987	18930	20556	22157	22607	22299	20985	19498	19607	19707	19669	20614	20445.2	20618.0
6. Step I Thermal Installations																
a) Large Thermal (includes plant sales)	4615	4615	4615	4615	4615	4615	4615	4615	4428	4081	3364	2111	3969	4615	4260.0	4310.6
b) Small Thermal	34	34	34	34	35	35	35	35	34	34	34	34	34	34	34.4	34.4
c) Combustion Turbines	2173	2089	2070	2310	2268	2310	2310	2310	2310	1853	1141	1607	1855	2212	2099.5	2122.9
d) Cogeneration (includes plant sales)	1584	1584	1574	1576	1578	1580	1581	1580	1580	1590	1499	967	1528	1584	1520.4	1528.6
e) Thermal PURPA/NUGS	263	263	247	234	230	226	222	228	233	258	257	268	256	267	244.4	242.4
f) Thermal classified as Renewables	51	51	51	51	51	51	51	51	51	51	51	51	51	51	50.7	50.7
g) Thermal Firm Imports	1251	1230	988	1142	1749	1967	1912	1794	1451	1176	1079	1037	1221	1318	1410.7	1436.6
h) Exclude Seas Exch Imports (see 3b) 4/	0	0	0	0	-280	-286	-286	-286	-30	-6	-6	0	0	0	-96.6	-109.8
i) Exclude Plant Sales (see 2b) 5/	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-40	-71	-102	-94.2	-95.3
j) ...Total	9869	9764	9477	9860	10143	10395	10338	10224	9956	8934	7317	6035	8844	9979	9429.2	9521.1
7. Total Step I Hydro Load (1929 water) 6/	9467	9623	9510	9070	10413	11762	12269	12075	11029	10564	12290	13671	10825	10635	11015.9	11096.9
a) Hydro Maintenance as a load	32	27	9	9	4	0	0	0	5	7	8	20	16	51	12.7	11.4
b) Coordinated Hydro Model Load (1929 water) 7/	10043	10125	10095	10046	11381	12836	13484	12765	11807	11332	13025	14347	11925	11275	11849.4	11963.0

1/ Step I Loads and Resources for the U.S. Optimum Study (01-11) 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 1 September 1928 and ends 29 February 1932.
3/ Includes 205 aMW uniform export of Canadian Entitlement. 1/3 is returned to Canada, 1/3 exported to SW, and 1/3 remained in the region.
4/ The Seasonal Exchange Imports are included in Thermal Firm Imports, line 6(g).
5/ Plant sales include Longview Fibre (Cogeneration, line 6(d)) and 15 percent of Boardman (Large Thermal, line 6(a)).
6/ Regulated hydro load for U.S. projects located upstream of Bonneville Dam, line 5 minus line 6(j).
7/ The Coordinated Hydro Model Load is the Step I Hydro Load plus Hydro Maintenance plus Non-Step I Coordinated Hydro.

TABLE 1B
2000-01 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**	24768	24723	24548	27308	29515	32066	33021	32018	29654	28080	28162	26369	25390	24984
a) Annual Load Shape in Percent	79.54	79.54	78.21	72.85	74.10	73.26	73.17	72.11	73.18	72.86	72.86	75.63	78.10	80.02
2. **Flows-Out of firm power from PNWA**														
a) Firm Exports 2/	2933	2933	2936	2329	1419	1407	1407	1483	1458	1450	1500	1729	2960	2983
b) Exclude Plant Sales	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-45	-116	-116
c) Firm Surplus	592	592	602	647	636	643	644	653	644	646	646	2032	1968	1921
d) ...Total	3409	3409	3422	2859	1938	1934	1934	2020	1985	1980	2030	3716	4812	4788
3. **Load served by Flows-In of firm power except Step I thermal installations**														
a) Non-thermal firm imports	-147	-147	-147	-147	-134	-148	-170	-194	-224	-147	-147	-147	-147	-147
b) Exclude Seasonal Exch Imports	0	0	0	0	-601	-601	-601	-601	-46	-12	-12	0	0	0
c) ...Total	-147	-147	-147	-147	-735	-749	-771	-795	-270	-159	-159	-147	-147	-147
4. **Loads served by non-Step I resources located withinin the PNWA**														
a) Hydro Independents (1937 water)	-1932	-1917	-1845	-1797	-1731	-1701	-1641	-1766	-1852	-1976	-2000	-2176	-2202	-2038
b) Non-Step I Coordinated Hydro (1937 water)	-2597	-2592	-2656	-2607	-2507	-2426	-2307	-2182	-2076	-1952	-2100	-2009	-2418	-2491
c) Non-Thermal PURPA/NUGS	-168	-168	-159	-151	-147	-143	-142	-145	-151	-165	-165	-172	-163	-171
d) Miscellaneous Resources	-38	-38	-41	-45	-351	-355	-355	-352	-350	-48	-48	-45	-44	-39
e) ...Total (1937 water)	-4735	-4715	-4700	-4600	-4735	-4624	-4445	-4445	-4429	-4140	-4313	-4403	-4827	-4739
5. **Total Step I System Firm Loads (1937 water)**	23296	23271	23123	25421	25983	28626	29739	28798	26941	25761	25721	25536	25229	24886
6. **Step I Thermal Installations**														
a) Large Thermal (includes plant sales)	5286	5286	5286	5286	5286	5286	5286	5286	5021	4809	3813	2528	4270	5286
b) Small Thermal	40	40	40	40	43	43	43	43	40	40	40	40	40	40
c) Combustion Turbines	2511	2333	2449	2750	2759	2764	2767	2762	2756	1895	1856	2345	2274	2518
d) Cogeneration (includes plant sales)	1650	1650	1639	1642	1644	1646	1647	1646	1646	1656	1656	1107	1261	1650
e) Thermal PURPA/NUGS	253	253	239	226	221	215	213	218	226	248	248	258	245	256
f) Thermal classified as Renewables	52	52	52	52	52	52	52	52	52	52	52	52	52	52
g) Thermal Firm Imports	1547	1550	1208	1479	2051	2277	2229	2185	1631	1291	1280	1680	1659	1546
h) Exclude Seas Exch Imports (see 3b) 3/	0	0	0	0	-601	-601	-601	-601	-46	-12	-12	0	0	0
i) Exclude Plant Sales (see 2b) 4/	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-116	-45	-116	-116
j) ...Total	11223	11048	10798	11359	11339	11566	11520	11475	11210	9863	8817	7965	9685	11232
7. **Total Step I Hydro Load (1937 water) 5/**	12073	12223	12325	14062	14644	17061	18219	17323	15731	15898	16904	17571	15544	13655
a) Hydro Maintenance as a load	4629	4066	3787	3208	2935	2037	1561	2295	2646	2751	2483	2360	2204	3725
b) Coordinated Hydro Model Load (1937 water) 6/	19299	18882	18768	19877	20085	21524	22088	21800	20452	20601	21487	21940	20166	19870

1/ Step I Loads and Resources for the U.S. Optimum study (01-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements. Total regional firm load plus pumping.

2/ Includes 467 aMW uniform export of Canadian Entitlement. 1/3 is returned to Canada, 1/3 exported to SW, and 1/3 remained in the region.

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

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

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

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

TABLE 2
2000-01 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 Mon)
1. STEP I THERMAL INSTALLATIONS																
a) From Table 1A, line 6(j)	9869	9764	9477	9860	10143	10395	10338	10224	9956	8934	7317	6035	8844	9979	9429.2	9521.1
2. MINIMUM THERMAL GENERATION																
a) Large Thermal Min. Generation	147	147	456	456	456	456	456	456	456	147	147	147	147	147	326.5	344.9
b) Cogen & Small Thermal Min. Gen	444	444	446	449	451	452	452	451	451	450	450	214	446	444	428.8	431.8
c) NUGS Thermal Min. Generation	88	88	82	78	77	75	74	76	78	86	86	89	85	89	81.5	80.8
d) ...Total Minimum Generation	679	679	984	983	984	983	982	983	985	683	683	450	678	680	836.7	857.6
3. DISPLACEABLE THERMAL RESOURCES	9190	9085	8492	8877	9159	9412	9356	9242	8971	8251	6634	5585	8165	9299	8592.5	8663.6
4. SYSTEM SALES																
a) Total Exports	1268	1268	1285	990	959	959	933	908	946	948	984	968	1315	1301	1067.1	1058.3
b) Exclude Can Entitlement (out of the PNWA)	-205	-205	-205	-205	-205	-205	-205	-205	-205	-205	-205	-205	-205	-205	-204.5	-204.5
c) Exclude Plant Sales Exports	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-40	-71	-102	-94.2	-95.3
d) Exclude Seasonal Exchange Exports	-272	-272	-283	-15	0	0	0	0	0	0	0	0	-283	-283	-94.8	-88.3
e) Firm Surplus Sales	471	471	471	471	471	471	471	471	471	471	471	1537	1537	1537	739.7	701.4
f) ...Total System Sales	1160	1160	1167	1139	1123	1124	1097	1073	1110	1113	1148	2261	2294	2249	1413.3	1371.6
g) Uniform Average Annual System Sales	1413	1413	1413	1413	1413	1413	1413	1413	1413	1413	1413	1413	1413	1413	1413.3	1413.3
5. THERMAL DISPLACEMENT MARKET	7777	7672	7079	7464	7746	7999	7942	7828	7558	6838	5221	4172	6752	7886	7179.3	7250.3

<u>Notes:</u>

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

00 1:51 PM W:\MG\TREATY\AOP01\FINAL\TB123_Final.XLW [TB2_01]

TABLE 3
2000-01 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	19741	93.52	24768	79.54	9869	17204.5	7335.7	14935.6	5066.8	August 1-15
August 16-31	19663	93.15	24723	79.54	9764	17136.6	7372.7	14876.6	5112.8	August 16-31
September	19199	90.96	24548	78.21	9477	16732.2	7255.5	14525.6	5048.9	September
October	19894	94.25	27308	72.85	9860	17337.7	7477.9	15051.2	5191.4	October
November	21871	103.61	29515	74.10	10143	19060.8	8917.6	16547.1	6403.9	November
December	23492	111.30	32066	73.26	10395	20474.0	10078.9	17773.9	7378.9	December
January	24161	114.47	33021	73.17	10338	21057.0	10719.4	18280.1	7942.4	January
February	23089	109.38	32018	72.11	10224	20122.3	9897.8	17468.6	7244.1	February
March	21701	102.81	29654	73.18	9956	18912.7	8956.6	16418.5	6462.4	March
April 1-15	20470	96.98	28080	72.86	8934	17840.1	8906.0	15487.4	6553.3	April 1-15
April 16-30	20567	97.44	28162	72.86	7317	17924.4	10607.4	15560.6	8243.6	April 16-30
May	19943	94.48	26369	75.63	6035	17380.6	11345.1	15088.5	9053.0	May
June	19829	93.94	25390	78.10	8844	17281.7	8437.9	15002.6	6158.9	June
July	19992	94.71	24984	80.02	9979	17423.3	7444.2	15125.5	5146.5	July
Annual Average 7/	21107.8	100.00		75.27	9429.2	18396.0	8966.7	15969.9	6540.7	Annual Average
SI CP Average (42)	21228.4			75.08	9521.1	18617.7	9032.9	16719.3	6854.4	CP avg (7 mo)
SII CP Average (20)	21362.2				9584.8					
SIII CP Average (7)	22098.2				9864.9					
						Input 5/ →	**9032.9**	Input 6/ →	**6854.4**	
August 1-31	19700.4	93.3	24768.2	79.54	9814.6	17169.4	7354.8	14905.2	5090.5	August 1-31
April 1-30	20518.4	97.2	28161.9	72.86	8125.6	17882.3	9756.7	15524.0	7398.4	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 1A, line 6(j)).
3/ The total firm load for the Step II/III studies is computed to have the same shape as the load of the PNWA.
4/ The hydro load is equal to the total load minus the Step I study thermal installations.
5/ Input is the assumed critical period (CP) average generation for the Step II hydro studies and is used to calculate the residual hydro loads.
6/ Input is the assumed Step III 7-month CP average generation: Input = 6854.4 MW excludes a 36 MW surplus in October (7-month CP average = 5.3 MW) which cannot be shaped to meet the firm loads.
7/ The Annual Average is for 2000-01 operating year, not a leap year.

TABLE 4
(English Units)
SUMMARY OF POWER REGULATIONS
FROM 2000-01 ASSURED OPERATING PLAN

PROJECTS	BASIC DATA		STEP I			STEP II				STEP III 1/			
	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE ksf	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE ksf	JANUARY 1945 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE ksf	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW
HYDRO RESOURCES													
CANADIAN													
Mica			7000			7000							
Arrow			7100			7100							
Duncan			1400			1400							
Subtotal			15500			15500							
BASE SYSTEM													
Hungry Horse	4	428	3072	359	104	3008	224	119	107	3008	344	178	106
Kerr	3	160	1219	154	114	1219	152	111	118	1219	150	126	120
Thompson Falls	6	85	0	85	54	0	85	53	57	0	85	59	57
Noxon Rapids	5	554	231	511	149	0	554	134	201	0	554	154	202
Cabinet Gorge	4	239	0	239	99	0	239	89	116	0	239	102	117
Albeni Falls	3	49	1155	22	22	1155	20	23	21	1155	20	18	21
Box Canyon	4	74	0	71	45	0	71	45	47	0	70	52	47
Grand Coulee	24+3SS	6684	5185	5911	1945	5072	6335	1763	2297	5072	5701	1171	2251
Chief Joseph	27	2614	0	2614	1118	0	2614	1017	1362	0	2614	717	1288
Wells	10	840	0	840	410	0	840	381	476	0	840	277	436
Chelan	2	54	677	51	38	676	51	36	45	676	51	44	43
Rocky Reach	11	1267	0	1267	576	0	1267	534	692	0	1267	376	648
Rock Island	18	523	0	494	254	0	494	238	299	0	494	171	278
Wanapum	10	986	0	986	518	0	986	482	600	0	986	330	542
Priest Rapids	10	912	0	912	510	0	912	477	572	0	912	337	513
Brownlee	5	675	975	675	240	974	675	314	316	974	675	267	316
Oxbow	4	220	0	220	99	0	220	124	128	0	220	116	128
Ice Harbor	6	693	0	693	213	0	693	233	304	0	693	179	304
McNary	14	1127	0	1127	691	0	1127	637	801	0	1127	482	747
John Day	16	2484	535	2484	891	0	2484	921	1252	0	2484	689	1216
The Dalles	22+2F	2074	0	2074	740	0	2074	724	983	0	2074	564	963
Bonneville	18+2F	1147	0	1147	594	0	1147	579	728	0	1147	450	692
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 2/		23889	29445	22936	9426	28500	23263	9033	11522	13000	22747	6860	11035
ADDITIONAL STEP I PROJECTS													
Libby	5	600	4980	549	194								
Boundary	6	1055	0	855	369								
Spokane River Plants	24	173	104	166	100								
Hells Canyon	3	450	0	410	193	NOT APPLICABLE TO STEP II & III							
Dworshak	3	450	2015	445	152								
Lower Granite	6	932	0	930	182								
Little Goose	6	932	0	928	181								
Lower Monumental	6	932	0	922	185								
Pelton, Rereg., & RB	7	423	274	418	126								
Total added Step 1		5947	7373	5624	1682								
THERMAL INSTALLATION 3/				11520	9521		11520	9585			11520	9865	
RESERVES, HYDRO MAINTENANCE 4/				-4203	-11		-2302	0			-1999	0	
TOTAL RESOURCES				35877	20618		32481	18618			32268	16725	
STEP I, II, & III LOADS 5/				29739	20618		28779	18618			24983	16719	
SURPLUS				6138	0		3702	0			7285	5	
CRITICAL PERIOD	Starts			September 1, 1928			September 1, 1943				October 1, 1936		
	Ends			February 29, 1932			April 30, 1945				April 30, 1937		
	Length (Months)			42 Months			20 Months				7 Months		
	Study Identification			01-41			01-42				01-13		

1/ Step III 7-month critical period average generation: Input = 6854.4 MW includes a 36 MW surplus in October (7-month critical period average = 5.3 MW) which cannot be shaped to meet the firm loads.

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

3/ From Tables 1 and 3.

4/ 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).

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

TABLE 4M
(Metric Units)
SUMMARY OF POWER REGULATIONS
FROM 2000-01 ASSURED OPERATING PLAN

PROJECTS	BASIC DATA: NUMBER OF UNITS	BASIC DATA: MAXIMUM INSTALLED PEAKING CAPACITY MW	STEP I: USABLE STORAGE hm^3	STEP I: JANUARY 1937 PEAKING CAP. MW	STEP I: CRITICAL PERIOD AVERAGE GEN. MW	STEP II: USABLE STORAGE hm^3	STEP II: JANUARY 1945 PEAKING CAP. MW	STEP II: CRITICAL PERIOD AVERAGE GEN. MW	STEP II: 30 YEAR AVERAGE ANNUAL GEN. MW	STEP III 1/: USABLE STORAGE hm^3	STEP III 1/: JANUARY 1937 PEAKING CAP. MW	STEP III 1/: CRITICAL PERIOD AVERAGE GEN. MW	STEP III 1/: 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	359	104	3710	224	119	107	3710	344	178	106
Kerr	3	160	1504	154	114	1504	152	111	118	1504	150	126	120
Thompson Falls	6	85	0	85	54	0	85	53	57	0	85	59	57
Noxon Rapids	5	554	285	511	149	0	554	134	201	0	554	154	202
Cabinet Gorge	4	239	0	239	99	0	239	89	116	0	239	102	117
Albeni Falls	3	49	1425	22	22	1425	20	23	21	1425	20	18	21
Box Canyon	4	74	0	71	45	0	71	45	47	0	70	52	47
Grand Coulee	24+3SS	6684	6396	5911	1945	6256	6335	1763	2297	6256	5701	1171	2251
Chief Joseph	27	2614	0	2614	1118	0	2614	1017	1362	0	2614	717	1288
Wells	10	840	0	840	410	0	840	381	476	0	840	277	436
Chelan	2	54	835	51	38	834	51	36	45	834	51	44	43
Rocky Reach	11	1267	0	1267	576	0	1267	534	692	0	1267	376	648
Rock Island	18	523	0	494	254	0	494	238	299	0	494	171	278
Wanapum	10	986	0	986	518	0	986	482	600	0	986	330	542
Priest Rapids	10	912	0	912	510	0	912	477	572	0	912	337	513
Brownlee	5	675	1203	675	240	1201	675	314	316	1201	675	267	316
Oxbow	4	220	0	220	99	0	220	124	128	0	220	116	128
Ice Harbor	6	693	0	693	213	0	693	233	304	0	693	179	304
McNary	14	1127	0	1127	691	0	1127	637	801	0	1127	482	747
John Day	16	2484	660	2484	891	0	2484	921	1252	0	2484	689	1216
The Dalles	22+2F	2074	0	2074	740	0	2074	724	983	0	2074	564	963
Bonneville	18+2F	1147	0	1147	594	0	1147	579	728	0	1147	450	692
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 2/		23889	36320	22936	9426	35155	23263	9033	11522	16036	22747	6860	11035
ADDITIONAL STEP I PROJECTS						NOT APPLICABLE TO STEP II & III							
Libby	5	600	6143	549	194								
Boundary	6	1055	0	855	369								
Spokane River Plants	24	173	128	166	100								
Hells Canyon	3	450	0	410	193								
Dworshak	3	450	2486	445	152								
Lower Granite	6	932	0	930	182								
Little Goose	6	932	0	928	181								
Lower Monumental	6	932	0	922	185								
Pelton, Rereg., & RB	7	423	338	418	126								
Total added Step 1		5947	9095	5624	1682								
THERMAL INSTALLATION 3/				11520	9521		11520	9585			11520	9865	
RESERVES, HYDRO MAINTENANCE 4/				-4203	-11		-2302	0			-1999	0	
TOTAL RESOURCES				35877	20618		32481	18618			32268	16725	
STEP I, II, & III LOADS 5/				29739	20618		28779	18618			24983	16719	
SURPLUS				6138	0		3702	0			7285	5	
CRITICAL PERIOD	Starts		September 1, 1928			September 1, 1943				October 1, 1936			
	Ends		February 29, 1932			April 30, 1945				April 30, 1937			
	Length (Months)		42 Months			20 Months				7 Months			
	Study Identification		01-41			01-42				01-13			

1/ Step III 7-month critical period average generation: Input = 6854.4 MW includes a 36 MW surplus in October (7-month critical period average = 5.3 MW) which cannot be shaped to meet the firm loads.

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

3/ From Tables 1 and 3.

4/ 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).

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

TABLE 5
(English & Metric Units)
COMPUTATION OF CANADIAN ENTITLEMENT FOR
2000-01 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S. (From 01-42)
B. Optimum Power Generation in the U.S. Only (From 01-12)
C. Optimum Power Generation in the U.S. and a 0.5 Million Acre-Feet (0.6 km^3) Reduction in Total Canadian Treaty Storage (From 01-22)

	CAPACITY ENTITLEMENT		
Determination of Dependable Capacity Credited to Canadian Storage (MW)	(A)	(B)	(C)
Step II - Critical Period Average Generation 1/	9032.9	9032.9	9003.2
Step III - Critical Period Average Generation 2/	6859.6	6859.6	6859.6
Gain Due to Canadian Storage	2173.3	2173.3	2143.6
Average Critical Period Load Factor in percent 3/	75.08	75.08	75.08
Dependable Capacity Gain 4/	2894.5	2894.5	2855.0
Canadian Share of Dependable Capacity 5/	1447.3	1447.3	1427.5

	ENERGY ENTITLEMENT		
Determination of Increase in Average Annual Usable Energy (aMW)			
Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Annual Firm Hydro Energy 6/	8967.3	8967.3	8938.0
Thermal Displacement Energy 7/	2183.3	2180.7	2196.6
Other Usable Secondary Energy 8/	148.7	149.7	152.4
System Annual Average Usable Energy	11299.3	11297.7	11287.0
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6541.1	6541.1	6541.1
Thermal Displacement Energy 7/	3239.8	3239.8	3239.8
Other Usable Secondary Energy 8/	501.5	501.5	501.5
System Annual Average Usable Energy	10282.4	10282.4	10282.4
Average Annual Usable Energy Gain 9/	1016.9	1015.3	1004.6
Canadian Share of Average Annual Energy Gain 5/	508.4	507.7	502.3

1/ Step II values were obtained from the 01-42, 01-12, and 01-22 studies, respectively.
2/ Step III values were obtained from the 01-13 study and Table 3. Includes 36 aMW of surplus in October which cannot be shaped to meet the firm loads.
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

	1996-97	1997-98	1998-99	1999-00	2000-01
AVERAGE PNWA ENERGY LOAD					
Annual Load (MW)	20324.6	20387.3	20479.6	20817.8	21107.8
Annual/January Load (%)	87.1	86.9	86.3	85.9	87.4
Critical Period (CP) Load Factor (%)	75.3	75.2	75.6	75.3	75.1
Annual Firm Exports	511.2	926.3	1075.3	1202.7	1067.1
Annual Firm Surplus (MW) 1/	610.5	433.2	534.6	708.1	739.7
THERMAL INSTALLATIONS (MW) 2/					
January Peak Capability	10381	10514	11003	11341	11520
CP Energy	7975	8141	8462	9019	9521
CP Minimum Generation	675	632	789	1071	858
Average Annual System Export Sales	887	1133	1265	1392	1413
Average Annual Displaceable Market	6104	6105	6345	6490	7179
HYDRO CAPACITY (MW)					
Total Installed	29785	29786	29786	29786	29836
Base System	23841	23856	23856	23856	23889
STEP I/II/III CP (MONTHS)	42/20/7	42/20/6	42/20/6.5	42/20/7	42/20/7
BASE STREAMFLOWS AT THE DALLES (cfs) 3/					
Step I 50-yr. Average Streamflow	179338	180748	181664	181664	181663
Step I CP Average	113053	114127	114496	114496	114496
Step II CP Average	100036	101008	101537	101525	101525
Step III CP Average	64756	64870	58483	64960	64959
BASE STREAMFLOWS AT THE DALLES (m^3/s) 3/					
Step I 50-yr. Average Streamflow	5078.28	5118.20	5144.15	5144.15	5144.12
Step I CP Average	3201.30	3231.71	3242.16	3242.16	3242.16
Step II CP Average	2832.70	2860.22	2875.20	2874.87	2874.85
Step III CP Average	1833.68	1836.92	1656.05	1839.47	1839.43
CAPACITY BENEFITS (MW)					
Step II CP Generation	8963.5	9018.0	9064.1	9080.4	9032.9
Step III CP Generation	6895.5	7169.4	6773.9	6878.8	6859.6
Step II Gain over Step III	2068.0	1848.6	2290.2	2201.7	2173.3
CANADIAN ENTITLEMENT	1373.4	1229.6	1514.7	1461.9	1447.3
Change due to Mica Reoperation	1.0	0.0	-0.4	0.2	0.0
Benefit in Sales Agreement	486.0	471.0	416.0	200.0	192.0
ENERGY BENEFITS (aMW)					
Step II Annual Firm Hydro	8871.0	8963.0	9000.0	8990.3	8967.3
Step II Thermal Displacement	2037.4	2037.7	2101.3	2129.5	2183.3
Step II Other Usable Secondary	207.0	194.9	188.3	193.5	148.7
Step II System Annual Average Usable	11115.4	11195.6	11289.6	11313.3	11299.3
Step III Annual Firm Hydro	6445.0	6579.0	6502.1	6422.2	6541.1
Step III Thermal Displacement	2951.6	2902.9	3066.8	3182.0	3239.8
Step III Other Usable Secondary	623.7	607.2	595.3	590.1	501.5
Step III System Annual Average Usable	10020.3	10089.1	10164.2	10194.3	10282.4
CANADIAN ENTITLEMENT	547.5	553.3	562.7	559.5	508.4
Change due to Mica Reoperation	-0.9	-2.8	-4.1	-0.8	0.7
ENTITLEMENT in Sales Agreement	254.0	246.0	215.0	103.0	99.0
STEP II PEAK CAPABILITY (MW)	31472	31647	32074	32421	32481
STEP II PEAK LOAD (MW)	26252	26587	27317	28386	28779
STEP III PEAK CAPABILITY (MW)	31409	31456	31793	32206	32268
STEP III PEAK LOAD (MW)	22350	22859	23391	24318	24983

FOOTNOTES FOR TABLE 6

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

AOP Study	Amount Shaped (MW)	
1996-97	276	1-31August, January through 30 April, June, and July,
	516	September through December, and
	3276	May.
1997-98	3000	May and
	2171	June.
1998-99	3199	May and June.
1999-00	4237	May and June.
2000-01	471	1 August through 30 April,
	1537	May through July.

2. Thermal installations include thermal imports and all existing and planned thermal resources. Beginning with the 1996-97 AOP, thermal installations also included cogeneration, renewable thermal, thermal NUG/PURPA, minus seasonal exchange imports and plant sales.

3. The 1990 level modified flows were used and no additional irrigation depletions were anticipated for the 2000-01 level. There is, however, an adjustment for Grand Coulee pumping and return flow.

CHART 1
2000-01 DDPB STUDIES
DURATION CURVES OF 30 YEARS MONTHLY HYDRO GENERATION (aMW)