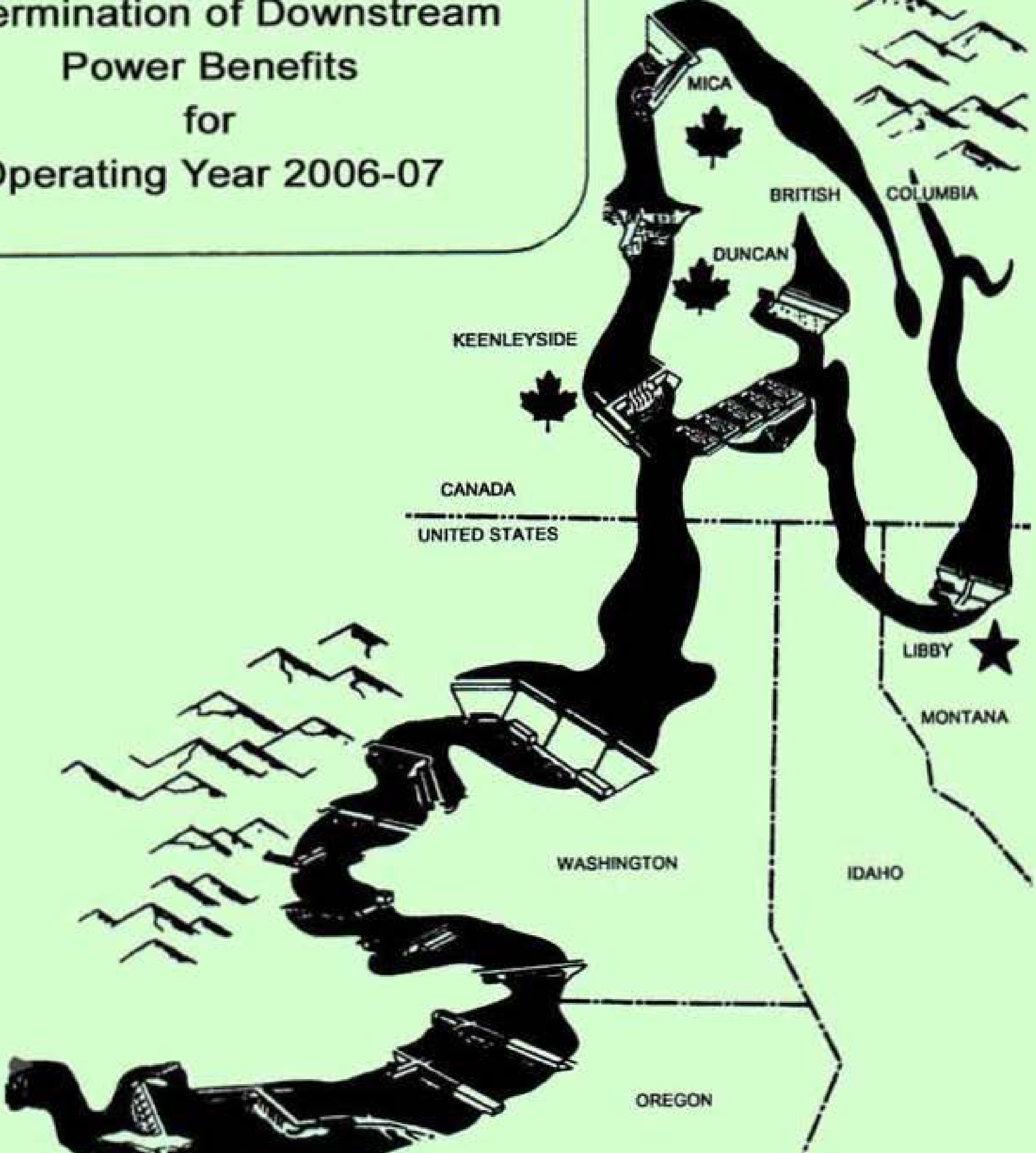
COLUMBIA RIVER TREATY
Assured Operating Plan
and
Determination of Downstream Power Benefits
for
Operating Year 2006-07



Columbia River Treaty Operating Committee

January 2004

COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
FOR OPERATING YEAR 2006-07

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1. Introduction

The treaty between Canada and the United States of America (USA) 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 AOP provides the Entities with an operating plan for Canadian Treaty Storage and information for planning the power systems that are dependent on or coordinated with the operation of the Canadian Treaty Storage projects.

This AOP was prepared in accordance with the following Entity Agreements:

- The Entity Agreements, signed 28 July and 12 August 1988, on "Principles for the Preparation of the AOP and Determination of Downstream Power Benefit (DDPB) Studies" and "Changes to Procedures for the Preparation of the AOP and DDPB Studies" (1988 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 (29 August 1996 Entity Agreement); and

- The "Columbia River Treaty Entity Agreement on the Principles and Procedures for Preparing and Implementing Hydroelectric Operating Plans For Operation of Canadian Treaty Storage" (POP), dated 16 December 2003.

The POP is based on criteria contained in Annex A and Annex B of the Columbia River Treaty,[1] the Protocol,[2] and the Columbia River Treaty Flood Control Operating Plan (FCOP).[3] For this AOP, the Entities have agreed to a Streamline Method that includes:

- Changes to procedures in Section 3.2.B(5) of the POP for determining the thermal installations that are described in Section 7(b) of this document;

- Use of the same USA Optimum and Joint Optimum Step I System Regulation Studies for the 2006-07, 2007-08, and 2008-09 AOP's, which is explained in more detail in Section 2(a) below; and

- Changes to procedures for performing the Steps II and III 30-year System Regulation Studies that are described in Section 6(d) of the 2006-07 DDPB.

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

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

(b) Operating rules and criteria for operation of the Canadian Treaty Storage in accordance with the principles contained in the above references; and

(c) The supporting data and model used to simulate the 30-year operation for the Step I Joint Optimum (AOP08-41) System Regulation Study.[4]

This AOP includes both metric (International Standard) and English units.[5] The System Regulation Studies and supporting data were based on English units. The 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 USA 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. Development of the Assured Operating Plan

a) System Regulation Studies

This AOP was prepared in accordance with Annex A, paragraph 7, of the Treaty, which requires Canadian Treaty Storage operation for joint optimum power generation in both Canada and the USA. Downstream power benefits were computed with the Canadian Treaty Storage operation based on the same criteria for joint optimum power generation as in the Step I study.

System regulation studies for this AOP were based on 2006-07 operating year estimated loads and resources for the USA Pacific Northwest Area, including estimated flows of power from and to adjacent areas, and hydro resources in the Columbia River Basin in British Columbia. As part of the Streamline Method for the joint preparation of the 2006-07, 2007-08, and 2008-09 AOP/DDPB's, the Entities have agreed to adjust the estimated seasonal exchange imports and exports, by less than 100 average annual MW each, so that the Step I System hydro loads are exactly the same for all three AOP's. With the same hydro load, the 2007-08 AOP Step I System Regulation Studies can serve as the basis for all three AOP's.

As required by Protocol VIII, the 2006-07 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 requirements, were used.[6] The 1990 level was considered the best estimate of irrigation depletions for the 2006-07 operating year at the time the 2006-07 AOP studies were initiated.

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

The flood control operation at Canadian projects was based on individual project flood control criteria instead of a composite curve. The Canadian Entity selected a 5.03/4.44 cubic kilometers (km^3) (4.08/3.6 million acre-feet (Maf)) Mica/Arrow flood control allocation in accordance with Section 6 of the FCOP. Flood Control and Variable Refill Curves are based on historical inflow volumes. Although only 19.12 km^3 (15.5 Maf) of usable storage are committed for power operation purposes under the Treaty, the FCOP provides for the full draft of the total 25.29 km^3 (20.5 Maf) of usable storage for on-call flood control purposes. Flood Control Rule Curves are implemented in the System Regulation Studies as URC's.

b) Evaluation of the Joint Optimum Study

In accordance with subsections 3.2.A and 3.3.A(3) of the POP, the changes in Canadian Treaty Storage operation for an optimum power generation at-site in Canada and downstream in Canada and the USA, compared to an operation for optimum power only in the USA, were evaluated as required by Annex A, paragraph 7, of the Treaty using the two criteria described below.

(1) Determination of Optimum Generation in Canada and the USA

To determine whether optimum power generation in both Canada and the USA was achieved in the system regulation studies, the annual firm energy capability, dependable peaking capability, and average annual usable secondary energy were computed for both the Canadian and USA systems. The Canadian Treaty Storage operation was designed to achieve a weighted sum of these three quantities that was greater than the weighted sum achieved under an operation of Canadian Treaty Storage for optimum power generation in the USA alone.

In order to measure optimum power generation for the 2006-07 AOP, the Columbia River Treaty Operating Committee agreed that the three quantities would be assigned the following relative values:

Quantity	Relative Value
Annual firm energy capability (average megawatts (aMW))	3
Dependable peaking capability (MW)	1
Average annual usable secondary energy (aMW)	2

The sum of the three weighted quantities showed a net gain in the study designed to achieve optimum power generation in Canada and the USA compared to the study designed to achieve optimum power generation in the USA alone. The Entities agree that this result is in accordance with subsection 3.2.A of the POP. The results of these calculations are shown in Table 2.

(2) Maximum Permitted Reduction in Downstream Power Benefits

Separate Step II system studies using the Streamline Method were developed reflecting: (i) Canadian Treaty Storage operation for optimum generation in the USA alone; and (ii) Canadian Treaty Storage operation for optimum generation in both Canada and the USA. Annex A, paragraph 7, of the Treaty defines the limits to any reduction in the downstream power benefits in the USA resulting from that change in operation. Using the storage operation for optimum generation in both Canada and the USA, there is a 1.5 aMW increase in the Canadian Entitlement for average annual usable energy and no change in the dependable capacity compared to the operation for optimum generation in the USA alone. (See Table 5 from the DDPB, columns A and B).

Since there is no reduction in entitlement, the Entities have determined in Section 3 of the 2006-07 DDPB that the calculation of maximum permitted reduction in downstream power benefits is not necessary.

3. Rule Curves

The operation of Canadian Treaty Storage during the 2006-07 Operating Year shall be guided by the ORC's and CRC's for the whole of Canadian Treaty Storage, Flood Control Storage Reservation Curves for the individual projects, and operating rules for specific projects. The ORC's and CRC's are first determined for the individual Canadian projects and then summed to yield the Composite ORC for the whole of Canadian Treaty Storage, in accordance with paragraph VII (2) of the Protocol. The ORC's are derived from the various curves described below.

(a) Critical Rule Curves

The CRC is defined by the end-of-period storage content of Canadian Treaty Storage during the critical period. It is used to determine proportional draft below the ORC as defined in subsection 4(b). The CRC's are adjusted for crossovers at each project by the hydroregulation model as defined in Section 2.3.A of the POP. The CRC's for Duncan, Arrow, Mica, and the Composite CRC's for the whole of Canadian Treaty Storage are included in Table 3.

(b) Refill Curves

There are two types of refill curves, the Assured Refill Curve (ARC) and the Variable Refill Curve (VRC), which are discussed in the following subsections. Tabulations of the ARC's and VRC's, and supporting data used in determining the ARC's and VRC's for Mica, Arrow, and Duncan, are provided in Tables 4-6, respectively.

(1) Assured Refill Curve

The ARC's indicate the minimum August through June end-of-period storage contents required to meet firm load and refill the Coordinated System storage by July 31st, based on the 1930-31 inflows. The upstream storage requirements and power discharge requirements (PDR's) are determined in accordance with Section 2.3.B and Appendix 1 of the POP. The 1930-31 inflows are the second lowest January through July unregulated streamflows at The Dalles, Oregon, during the 30-year streamflow period, which has approximately a 95% probability of exceedance.

(2) Variable Refill Curve

The VRC's indicate the minimum January through June end-of-period storage contents required to refill the Coordinated System storage by July 31st, based on the 95% confidence forecasted inflow volume. The upstream storage refill requirements, PDR's, and VRC lower limits (VRCLL's) are determined in accordance with Section 2.3.B and Appendix 1 of the POP. In the system regulation studies, historical volume inflows, adjusted for the 95% confidence forecast error, were used instead of forecasted inflows. The PDR's and VRCLL's are a function of the unregulated January through July runoff volume at The Dalles, Oregon. In those years when the January through July runoff volume at The Dalles is between 98.68 km^3 (80 Maf) and 135.69 km^3 (110 Maf), the PDR's and VRCLL's were interpolated linearly between the values shown in Tables 4-6. In those years when the January through July runoff volume at The Dalles was less than 98.68 km^3 (80 Maf), or greater than 135.69 km^3 (110 Maf), the PDR and VRCLL values for 98.68 km^3 and 135.69 km^3 (80 and 110 Maf), respectively, were used.

Tables 4-6 illustrate the range of VRC's for Mica, Arrow, and Duncan for the 30-year streamflow period. In actual operation, in 2006-07, the PDR's and VRCLL's will be based on the forecast of unregulated runoff at The Dalles.

(c) Operating Rule Curve Lower Limit (ORCLL)

The ORCLL's (also called Energy Content Curve Lower Limits) indicate the minimum 31 January through 15 April end-of-period storage contents that must be maintained to protect the ability of the system to meet firm load during the period 1 January through 30 April. The ORCLL's protect the system's ability to meet firm load 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 ORC to be no lower than the ORCLL's. The ORCLL's are developed for 1936-37 water conditions which includes the lowest January through April unregulated streamflows at The Dalles during the 30-year streamflow period. The ORCLL'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 Treaty 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 FCOP and analysis of system flood control simulations. URC's for Mica, Arrow, and Duncan for the 30-year streamflow period are shown in Tables 7-9 respectively. Tables 7 and 8 reflect an agreed transfer of flood control space in Mica and Arrow to maximum drafts of 5.03 and 4.44 km^3 (4.08 and 3.6 Maf) respectively. In actual operation, the URC's will be computed as outlined in the FCOP 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 USA 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 (CRC1) or the ARC, whichever is higher. During the period 1 January through 31 July, the ORC is defined as the higher of the CRC1 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 ORCLL. The ORC shall be less than or equal to the URC at each individual project. The composite ORC's for the whole of Canadian Treaty Storage for the 30-year streamflow period are included in Table 10 to illustrate the probable future range of these curves based on historical conditions.

4. Operating Rules

Under the Streamline Method, the AOP08-41 System Regulation Study was utilized to develop and test the operating rules and rule curves. It contains the agreed-upon ORC's and CRC's, and operating procedures and constraints, such as maximum and minimum project elevations, discharges, and draft rates. These constraints are included as part of this operating plan and are listed in Appendices A1 and A2.

The following rules and other operating criteria included in the AOP08-41 System Regulation Study will apply to the operation of Canadian Treaty Storage in the 2006-07 Operating Year.

a) Operation At or Above ORC

The whole of Canadian Treaty Storage will be drafted to its ORC as required to produce optimum generation in Canada and the USA in accordance with Annex A, paragraph 7, of the Treaty, subject to project physical characteristics and operating constraints.

b) Operation Below ORC

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

c) Mica Project Operation

In this AOP, Mica reservoir will be operated in accordance with operating criteria listed in Table 1, so as to optimize generation at site, downstream at Revelstoke and Keenleyside, and downstream in the USA. In general, the Mica operating criteria in each period are determined by Arrow's storage content at the end of the previous period. 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.

In the event that Mica's operation to the Table 1 operating criteria results in more or less than the project's share of draft from the whole of Canadian Treaty Storage as described in 4(a) or 4(b) above, compensating changes will be made from Arrow to the extent possible.

Mica storage releases in excess of 8.63 km^3 (7.0 Maf) 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 17.39 km^3 (14.1 Maf), unless flood control or minimum flow criteria will not permit the additional Mica storage releases to be retained at Arrow. Should storage releases in excess of 17.39 km^3 (14.1 Maf) be made, the target Mica operation will remain as specified in Table 1.

d) Arrow Project Operating Criteria (APOC)

In this AOP, Arrow reservoir storage operation will be limited to a maximum storage level defined by the APOC during the period January through June. The APOC shall be calculated as follows:

(1) During January through March, the APOC will be determined using the following table and the forecast of unregulated April through August volume runoff at The Dalles.

The Dalles Apr-Aug Inflow Vol.		Arrow Project Operating Criteria Maximum Storage					
		km³			Maf		
km³	**Maf**	**31-Jan**	**28-Feb**	**31-Mar**	**31-Jan**	**28-Feb**	**31-Mar**
0	0	7.524	7.524	7.524	6.100	6.100	6.100
78.9	64	7.524	7.524	7.524	6.100	6.100	6.100
80.2	65	7.397	7.281	7.154	5.997	5.903	5.800
86.4	70	6.845	6.230	5.551	5.549	5.051	4.500
92.5	75	6.292	5.179	3.947	5.101	4.199	3.200
98.7	80	5.783	4.209	2.467	4.688	3.412	2.000
1233.5	1000	5.783	4.209	2.467	4.688	3.412	2.000

For intermediate forecast volumes, the APOC will be interpolated linearly between the values shown above.

(2) During April through June, the APOC will be based on the same monthly percent refill as the April through June Arrow URC. For example:

April APOC = March APOC + (Full – March APOC) * April URC Percent Refill
Where April URC Percent Refill = (April URC – March URC) / (Full – March URC)

(3) The APOC storage levels shall be less than or equal to the URC.

e) Other Canadian Project Operation

Revelstoke, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile, and Waneta have been included in the 2006-07 AOP as run-of-river projects. Generation at Arrow was modeled in the studies. Corra Linn and Kootenay Canal were included and operated in accordance with criteria that closely approximate International Joint Commission rules for Kootenay Lake.

5. Implementation

The Entities have to this date 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 2006-07 DOP will reflect the latest available load, resource, and other pertinent data to the extent the Entities agree that 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 2006-07 DOP. Failing agreement on updating the data and/or criteria, the 2006-07 DOP for Canadian Treaty Storage shall include the rule curves, Mica and Arrow operating criteria, and other data and criteria provided in this AOP. Actual operation of Canadian Treaty Storage during the 2006-07 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 Treaty 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 FCOP. When refill of Canadian Treaty 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.

6. Canadian Entitlement

The amount of Canadian Entitlement is defined in the companion document "Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2006-07."

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 near Oliver, the Entities completed an agreement on Aspects of the Delivery of the Canadian Entitlement for 1 April 1998 through 15 September 2024, dated 29 March 1999.[7] This arrangement covers the full 1 August 2006 through 31 July 2007 period covered by this AOP, and includes transmission losses and scheduling guidelines for delivery of the Canadian Entitlement.

7. Summary of Changes from the 2005-06 AOP and Notable Assumptions

Data from the recent AOP's are summarized in Table 11. Since the 2006-07, 2007-08, and 2008-09 AOP's are based on the same Step I System Regulation Studies, the changes shown in this section are compared to the 2005-06 AOP. An explanation of the more important changes and notable assumptions follows.

(a) Loads

Loads for the 2006-07 AOP were based on Bonneville Power Administration's (BPA) December 2000 White Book (WB) medium-case load forecast. This new forecast was the first major update to BPA's regional load forecast procedures since 1996. The previous forecast had a 0.5% average annual load growth rate and the new forecast has a 1.6% average annual load growth rate from the 2005-06 to the 2006-07 operating year. The change in load growth rate is mostly due to more detailed estimates for investor owned utilities and a significant reduction in direct service industry (mainly aluminum) loads. The net effect of the new load forecast is that the Pacific Northwest Area firm load in the 2006-07 AOP is 1,520 aMW (6.8%) greater than that in the 2005-06 AOP. Other regional load forecasts are not available for 2006-07 operating year; however, the 2000 WB load forecast for the 2005-06 operating year compares well and is slightly lower than the Northwest Power Planning Council load forecast. Other load changes include:

- It was assumed that one-half of the Canadian Entitlement was exported to B.C., and the remaining one-half was disposed in the USA. The estimated disposition of the Entitlement in the Step I system was based on the 2005-06 DDPB. The estimated and the computed Canadian Entitlement are shown below:

  During 1 August 2006 – 31July 2007

Canadian Entitlement	Energy (aMW)		Capacity (MW)	
Return	Estimated	Computed	Estimated	Computed
Export to BC (1/2)	267.6	244.3	609.0	622.2
Retained in PNW (1/2)	267.6	244.3	609.0	622.2
Total	535.1	488.5	1218.0	1244.3

  Iterative studies to update the Canadian Entitlement in the load estimate were not performed because they would change the Step I System energy load by about 0.1%, which would not significantly affect the results of the studies.

- Compared to the 2005-06 AOP, Flows-Out (exports that are mostly to the Southwest) decreased by 681 aMW, mainly due to expiration of several firm contracts. Flows-In (Imports) increased by 161 aMW.

- The Step I System Load is reduced by Hydro Independent generation, Non-Step I Coordinated Hydro, and Miscellaneous Non-Thermal Resources. The most notable change was a 412 aMW increase in Miscellaneous Non-Thermal Resources, mainly numerous wind generators.

(b) Thermal Installations

Because of increasing difficulty in forecasting Thermal Installations, the Entities changed procedures for determining Thermal Installations in this AOP/DDPB by assuming one generic Thermal Installation, except for the Columbia Generating Station (CGS, formerly called Washington Public Power Supply System #2 nuclear power plant). The quantity of generic Thermal Installation was defined as the amount needed, together with the CGS, to meet the Step I System Load minus Step I Hydro capability. The annual shape of the generic Thermal Installation was the same as the 2005-06 AOP Thermal Installations not including the CGS. The CGS was modeled separately because of its large size and a two-year maintenance cycle with outages only in the second half of May and June during odd years. The total Thermal Installations increased by 263 aMW compared to the 2005-06 AOP.

(c) Hydro Project Operating Procedures

The nonpower requirements for Base System projects were agreed to in the 29 August 1996 Entity Agreement. These requirements are essentially the nonpower requirements included in the 1979-80 and prior AOP/DDPB studies.

The critical rule curves, refill curves, and Mica operating criteria were updated in accordance with procedures defined in the POP, except that the VRCLL's were not updated from the 2005-06 AOP. Other changes and notable assumptions include:

Canadian Projects

- Flood control data reflects an agreed allocation of flood control space in Mica and Arrow of 5.03 and 4.44 km^3 (4.08 and 3.6 Maf), respectively. In the 2005-06 and prior AOP's the flood control allocation was 2.57 and 6.29 km^3 (2.08 and 5.1 Maf).
- The APOC referred to in subsection 4(d) was implemented through use of maximum storage limits.

Base System Projects

- The Brownlee storage operation outside the critical period was simulated by using CRC's and ORC's instead of the fixed operation from Idaho Power Company (IPC), used in the 2003-04 and previous AOP's. The CRC's were based on the IPC's forecast of critical period operation during 1929-1932 for the Step I studies, 1944-45 for Step II, and 1937 for Step III. ORC's were revised compared to the 2005-06 AOP to more closely follow the historic forecast of IPC operation.

Non-Base System Projects

- During April through June, Dworshak is no longer required to meet target flows at Lower Granite. Dworshak will operate to minimum flow or flood control during September through June, and during July through August Dworshak will operate to meet Lower Granite target flows, subject to minimum storage limits.

- Lower Granite, Little Goose, and Lower Monumental fish spill was updated for April 15 through June. Lower Granite and Little Goose spill decreased while Lower Monumental increased.

- Storage limits were updated for Round Butte, Timothy, Long Lake, and Priest Lake.

- Generation plant data tables for Mossyrock were updated. This change did not significantly affect the system operation.

End Notes

1 "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.

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

3 "Columbia River Treaty Flood Control Operating Plan," dated October 1999, subsequently superceded by the Plan of May 2003.

4 "BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 08-41," dated 10 October 2003.

5 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).

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

7 "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.

TABLE 1

(English Units)

MICA PROJECT OPERATING CRITERIA

2006-07 ASSURED OPERATING PLAN

Month	End of Previous Month Arrow Storage Content (ksfd)	Target Operation: Month Outflow (cfs)	Target Operation: End-of-Month Treaty Storage Content 1/ (ksfd)	Target Operation Limits: Minimum Treaty Storage Content 2/ (ksfd)	Target Operation Limits: Maximum Outflow 1/ (cfs)	Target Operation Limits: Minimum Outflow (cfs)
August 1-15	3,570 - FULL	-	3,454.2	-	34,000	15,000
	2,390 - 3,570	25,000	-	0	-	15,000
	0 - 2,390	32,000	-	0	-	15,000
August 16-31	3,570 - FULL	-	3,529.2	-	-	15,000
	3,450 - 3,570	-	3,364.2	-	34,000	15,000
	3,000 3,450	25,000	-	0	-	15,000
	0 - 3,000	32,000	-	0	-	15,000
September	3,570 - FULL	-	3,529.2	-	-	10,000
	3,390 - 3,570	22,000	-	0	-	10,000
	2,510 - 3,390	27,000	-	0	-	10,000
	0 - 2,510	32,000	-	0	-	10,000
October	3,570 - FULL	-	3,428.4	-	34,000	10,000
	3,120 - 3,570	20,000	-	0	-	10,000
	750 - 3,120	22,000	-	0	-	10,000
	0 - 750	32,000	-	0	-	10,000
November	3,450 - FULL	20,000	-	0	-	10,000
	3,020 - 3,450	19,000	-	0	-	10,000
	630 - 3,020	25,000	-	0	-	10,000
	0 - 630	32,000	-	0	-	10,000
December	3,340 - FULL	25,000	-	390.1	-	10,000
	2,870 - 3,340	22,000	-	390.1	-	10,000
	900 - 2,870	27,000	-	390.1	-	10,000
	0 - 900	32,000	-	390.1	-	10,000
January	2,740 - FULL	24,000	-	134.1	-	10,000
	2,530 - 2,740	26,000	-	134.1	-	10,000
	1,630 - 2,530	28,000	-	134.1	-	10,000
	0 - 1,630	30,000	-	134.1	-	10,000
February	1,510 - FULL	21,000	-	164.1	-	10,000
	1,350 - 1,510	25,000	-	164.1	-	10,000
	1,140 - 1,350	20,000	-	164.1	-	10,000
	0 - 1,140	26,000	-	164.1	-	10,000
March	620 - FULL	18,000	-	120.3	-	10,000
	480 - 620	19,000	-	120.3	-	10,000
	70 - 480	20,000	-	120.3	-	10,000
	0 - 70	22,000	-	120.3	-	10,000
April 1-15	1,000 - FULL	18,000	-	15.3	-	11,000
	960 - 1,000	27,000	-	15.3	-	11,000
	770 - 960	12,000	-	15.3	-	11,000
	0 - 770	18,000	-	15.3	-	11,000
April 16-30	920 - FULL	12,000	-	0	-	10,000
	490 - 920	15,000	-	0	-	10,000
	20 - 490	12,000	-	0	-	10,000
	0 - 20	15,000	-	0	-	10,000
May	1,140 - FULL	10,000	-	0	-	10,000
	680 - 1,140	15,000	-	0	-	10,000
	0 - 680	10,000	-	0	-	10,000
June	1,820 - FULL	10,000	-	0	-	10,000
	1,590 - 1,820	15,000	-	0	-	10,000
	1,090 - 1,590	10,000	-	0	-	10,000
	0 - 1,090	15,000	-	0	-	10,000
July	3,340 - FULL	-	3,379.2	-	34,000	10,000
	2,250 - 3,340	-	3,317.2	-	34,000	10,000
	1,520 - 2,250	19,000	-	0	-	10,000
	0 - 1,520	30,000	-	0	-	10,000

1/ If the Mica target end-of-month storage content is less than 3529.2 ksfd, then a maximum outflow of 34000 cfs will apply.
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 2006-07 ASSURED OPERATING PLAN
STUDY RESULTS

Study 07-41 provides Optimum Generation in Canada and in the United States.
Study 07-11 provides Optimum Generation in the United States only.

	Study No. 07-41	Study No. 07-11	Net Gain	Weight	Value
1. Firm Energy Capability (aMW)					
U.S. System 1/	12088.5	12088.6	-0.2		
Canada 2/, 3/	2902.7	2812.5	90.3		
Total	14991.2	14901.1	90.1	3	270.3
2. Dependable Peaking Capacity (MW)					
U.S. System 4/	31121.0	31142.0	-21.0		
Canada 2/, 5/	5653.0	5642.0	11.0		
Total	36774.0	36784.0	-10.0	1	-10.0
3. Average Annual Usable Secondary Energy (aMW)					
U.S. System 6/	3075.5	3075.2	0.3		
Canada 2/, 7/	262.1	291.3	-29.3		
Total	3337.6	3366.5	-29.0	2	-57.9
			Net Change in Value =		202.4

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

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

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

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

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

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

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

TABLE 3
(English Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2006 - 07 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	3529.2	3515.9	3529.2	3401.6	3003.1	2264.7	1522.5	706.0	582.2	220.3	32.4	492.7	2126.3	3017.4
1929-30	3479.0	3329.2	3226.6	2391.5	1953.1	1428.9	502.3	79.6	0.0	22.9	0.0	368.6	825.5	2595.5
1930-31	2914.1	3034.4	3117.1	2357.6	1937.2	1281.8	526.1	74.9	0.0	21.7	0.0	351.5	753.1	1205.3
1931-32	1201.7	1096.7	800.3	1051.4	616.9	24.9	31.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	3579.6	3575.4	3106.2	2847.1	2679.8	2373.6	1410.0	823.0	622.3	544.7	601.1	1487.4	3040.6	3485.2
1929-30	3371.8	3443.2	2846.0	2736.8	1926.7	1347.8	398.5	83.5	0.0	55.0	183.6	1163.9	2592.4	3051.1
1930-31	3199.8	3215.1	2788.1	2734.4	1999.8	1329.4	532.5	107.9	0.0	63.8	54.8	966.7	2095.9	2680.3
1931-32	2682.1	2614.4	2130.9	1218.9	794.6	385.8	103.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	705.8	694.8	705.8	651.9	621.3	495.5	413.2	338.0	131.0	74.3	82.7	200.2	475.0	645.1
1929-30	590.7	653.7	705.8	703.0	535.2	494.4	345.7	145.9	0.1	12.0	22.8	137.8	320.5	477.7
1930-31	481.4	513.8	570.4	566.7	476.6	341.7	185.9	89.3	0.0	2.0	0.0	83.5	50.7	60.1
1931-32	33.9	46.7	117.2	51.4	72.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	7814.6	7786.1	7341.2	6900.6	6304.2	5133.8	3345.7	1867.0	1335.5	839.3	716.2	2180.3	5641.9	7147.7
1929-30	7441.5	7426.1	6778.4	5831.3	4415.0	3271.1	1246.5	309.0	0.1	89.9	206.4	1670.3	3738.4	6124.3
1930-31	6595.3	6763.3	6475.6	5658.7	4413.6	2952.9	1244.5	272.1	0.0	87.5	54.8	1401.7	2899.7	3945.7
1931-32	3917.7	3757.8	3048.4	2321.7	1484.0	411.0	134.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 4
(English Units)
MICA
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, VARIABLE REFILL CURVE LOWER LIMITS, AND OPERATING RULE CURVE LOWER LIMITS
2006 - 07 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	245.6	809.8	1413.1	1591.4	1656.7	1673.2	1668.0	1656.6	1663.4	1688.6	1669.4	2348.1	3528.8	3529.2
VARIABLE REFILL CURVES (KSFD)														
1928-29							2807.5	2692.0	2652.7	2658.2	2699.0	3144.4	3396.3	3529.2
1929-30							1783.2	1628.4	1579.6	1603.2	1759.7	2537.2	3112.1	"
1930-31							2042.8	1896.9	1843.5	1845.4	1935.5	2557.1	3187.3	"
1931-32							1595.9	1457.3	1410.5	1413.1	1538.5	2262.8	3067.8	"
1932-33							1500.3	1397.0	1367.5	1368.1	1445.7	2160.1	2904.4	"
1933-34							685.5	600.3	565.4	580.4	743.1	1908.4	3157.1	"
1934-35							1769.4	1647.4	1630.3	1650.8	1720.9	2365.7	2982.9	"
1935-36							1549.1	1427.5	1399.0	1399.0	1494.3	2310.0	3241.9	"
1936-37							2795.7	2659.6	2605.6	2600.3	2689.0	3158.0	3428.6	"
1937-38							1873.5	1751.8	1705.0	1712.1	1805.0	2486.1	3159.3	"
1938-39							1846.9	1769.4	1730.0	1757.8	1869.1	2580.4	3420.1	"
1939-40							1626.7	1512.6	1490.4	1512.0	1641.5	2375.1	3179.9	"
1940-41							2224.7	2099.7	2065.8	2087.1	2264.4	2934.0	3410.1	"
1941-42							2277.9	2156.4	2114.3	2106.7	2182.8	2785.7	3312.4	"
1942-43							2509.4	2365.4	2320.4	2318.2	2470.7	3113.4	3397.7	"
1943-44							2903.0	2751.2	2710.8	2708.7	2777.2	3264.3	3529.2	"
1944-45							2825.8	2711.1	2684.5	2698.9	2748.3	3191.6	3486.3	"
1945-46							1292.6	1140.4	1092.1	1082.3	1174.0	1958.7	3062.2	"
1946-47							1411.4	1313.0	1293.4	1305.3	1421.7	2223.1	3132.7	"
1947-48							1360.4	1241.3	1206.5	1192.3	1272.2	2018.6	3019.4	"
1948-49							3056.9	2912.3	2850.6	2848.1	2925.2	3394.4	3529.2	"
1949-50							1715.9	1557.3	1498.9	1489.4	1573.9	2239.7	2830.7	"
1950-51							1707.1	1596.2	1569.8	1578.1	1691.6	2358.8	3192.2	"
1951-52							2113.9	1960.4	1908.5	1893.4	1974.7	2654.2	3339.5	"
1952-53							2395.1	2259.4	2217.1	2214.7	2274.1	2809.4	3306.4	"
1953-54							1270.9	1147.4	1129.7	1133.4	1217.0	1934.7	2802.8	"
1954-55							2030.6	1923.2	1897.2	1907.6	1993.7	2580.5	2997.2	"
1955-56							1579.0	1454.0	1407.3	1400.4	1488.8	2256.7	3106.7	"
1956-57							1747.6	1615.3	1583.2	1588.6	1677.6	2342.9	3437.3	"
1957-58							1581.3	1461.9	1436.4	1447.0	1552.1	2239.6	3199.8	"
DISTRIBUTION FACTORS							0.9750	0.9770	0.9740	0.9812	0.9650	0.7950	0.4950	N/A
FORECAST ERRORS (KSFD)							652.9	510.3	465.3	444.4	444.4	360.4	360.4	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	8494	6167	20819	56466
VARIABLE REFILL CURVES					80 MAF		3000	3000	3000	3000	3000	3000	34000	40000
(BY VOLUME RUNOFF AT THE DALLES)					95 MAF		3000	3000	3000	3000	3000	3000	34000	40000
					110 MAF		3000	3000	3000	3000	3000	3000	34000	40000
VARIABLE REFILL CURVE LOWER LIMITS (KSFD)					80 MAF		224.9	241.3	270.8	331.0	470.1	1460.8	2823.8	3529.2
(BY VOLUME RUNOFF AT THE DALLES)					95 MAF		39.3	0.0	20.7	27.3	0.0	681.8	2297.2	3529.2
					110 MAF		11.9	0.0	0.0	0.0	3.7	658.7	1809.5	3529.2
OPERATING RULE CURVE LOWER LIMITS (KSFD)							298.6	35.2	0.0	0.5				

TABLE 5
(English Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, VARIABLE REFILL CURVE LOWER LIMITS, AND OPERATING RULE CURVE LOWER LIMITS
2006 - 07 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	0.0	0.0	0.0	42.4	575.4	1366.3	2007.3	2041.5	2116.9	2177.3	1654.0	2752.8	2953.7	3579.6
VARIABLE REFILL CURVES (KSFD)														
1928-29							2494.8	2300.7	2156.6	2118.8	2277.6	2739.6	3039.6	3579.6
1929-30							866.7	726.4	729.5	726.0	1010.0	2140.4	"	"
1930-31							1334.0	1130.0	1014.8	997.5	1219.4	2118.5	"	"
1931-32							6.3	0.1	17.8	11.0	12.3	990.8	2789.5	"
1932-33							4.9	0.0	17.6	7.3	9.7	1140.9	2760.7	"
1933-34							3.0	0.0	17.3	2.6	6.5	1464.5	2866.2	"
1934-35							163.2	82.5	297.7	355.5	579.5	1672.9	2987.0	"
1935-36							149.3	103.4	194.2	286.0	419.8	1629.5	2995.5	"
1936-37							2814.7	2567.8	2422.6	2345.8	2520.0	2923.1	3039.6	"
1937-38							458.7	328.4	444.5	492.9	788.3	1887.6	2778.7	"
1938-39							1066.2	918.1	813.7	796.7	1104.1	2118.5	3039.6	"
1939-40							614.6	583.3	580.2	674.1	900.6	"	"	"
1940-41							1966.6	1815.2	1737.4	1838.1	2296.6	3016.4	3129.8	"
1941-42							1837.4	1692.9	1801.4	1783.5	2033.0	2659.5	2987.2	"
1942-43							2281.9	2068.6	2147.1	2111.8	2230.3	3504.4	3579.6	"
1943-44							3320.8	3130.3	3004.2	2936.8	3128.0	3475.8	3219.6	"
1944-45							2670.9	2520.3	2431.0	2414.5	2562.9	2949.3	3138.3	"
1945-46							2.1	0.0	17.2	0.1	4.8	1051.3	2704.9	"
1946-47							145.1	40.5	17.8	32.3	266.4	1439.1	2789.8	"
1947-48							2.0	0.0	17.2	0.0	4.7	1130.8	2703.8	"
1948-49							1906.3	1713.8	1816.9	1810.0	2093.4	2735.0	3230.7	"
1949-50							2.0	0.0	17.2	0.0	89.7	1754.7	2703.8	"
1950-51							190.2	141.5	234.2	218.7	556.4	2019.0	2774.9	"
1951-52							645.6	449.5	561.5	528.9	782.4	2019.6	3007.0	"
1952-53							1312.3	1138.6	1255.2	1245.8	1450.3	2549.5	2953.8	"
1953-54							2.0	0.0	17.2	0.0	4.7	900.0	2891.7	"
1954-55							275.4	187.8	347.8	346.8	630.4	1721.9	2952.5	"
1955-56							2.0	0.0	17.2	0.0	4.7	1113.2	2703.8	"
1956-57							"	"	"	"	"	955.9	2743.2	"
1957-58							5.6	0.1	17.7	9.2	11.0	984.0	2775.0	"
DISTRIBUTION FACTORS							0.9710	0.9747	0.9691	0.9741	0.9530	0.7483	0.4631	N/A
FORECAST ERRORS (KSFD)							1233.1	987.3	825.3	715.1	715.1	501.4	501.4	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	56663	10761	68580	68385
VARIABLE REFILL CURVES					80 MAF		5000	5000	5000	5000	8000	8000	50000	50000
(BY VOLUME RUNOFF AT THE DALLES)					95 MAF		5000	5000	5000	5000	5000	5000	50000	50000
					110 MAF		5000	5000	5000	5000	5000	5000	50000	50000
VARIABLE REFILL CURVE LOWER LIMITS (KSFD)					80 MAF		138.7	211.9	378.4	553.0	833.0	2118.5	3039.6	3579.6
(BY VOLUME RUNOFF AT THE DALLES)					95 MAF		14.6	0.2	18.9	32.1	26.7	1164.4	2953.5	3579.6
					110 MAF		2.0	0.0	17.2	0.0	4.7	900.0	2703.8	3579.6
OPERATING RULE CURVE LOWER LIMITS (KSFD)							251.3	18.4	0.0	1.3				

TABLE 6
(English Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, VARIABLE REFILL CURVE LOWER LIMITS, AND OPERATING RULE CURVE LOWER LIMITS
2006 - 07 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	0.0	62.7	129.0	159.7	177.2	188.4	198.6	207.8	221.9	235.1	248.3	405.3	555.3	705.8
VARIABLE REFILL CURVES (KSFD)														
1928-29							488.7	473.5	458.1	450.7	444.6	486.6	623.1	705.8
1929-30							487.1	471.5	455.8	448.1	456.2	507.1	634.6	"
1930-31							431.6	417.3	405.2	402.5	402.1	456.6	623.1	"
1931-32							77.7	75.9	83.6	91.7	134.3	248.6	519.6	"
1932-33							10.8	4.3	4.1	0.0	9.8	128.1	462.4	"
1933-34							68.0	83.3	96.3	110.4	181.0	308.1	577.7	"
1934-35							189.0	189.1	195.1	195.8	209.9	306.2	535.5	"
1935-36							148.3	141.7	136.3	134.1	148.5	281.5	558.6	"
1936-37							436.6	421.3	407.7	400.0	393.9	449.1	605.2	"
1937-38							148.4	153.9	159.3	166.6	197.4	303.8	544.2	"
1938-39							283.5	274.8	264.9	261.1	268.5	369.4	605.9	"
1939-40							267.2	263.5	261.0	266.8	275.8	371.5	594.4	"
1940-41							348.9	342.4	335.7	342.8	360.7	447.9	618.2	"
1941-42							296.2	298.8	300.0	301.9	318.7	400.8	588.6	"
1942-43							279.4	280.1	283.7	285.7	317.2	413.6	577.2	"
1943-44							505.3	495.0	484.5	479.1	475.2	519.3	653.3	"
1944-45							419.3	411.1	402.6	397.8	393.8	446.6	609.7	"
1945-46							25.1	22.7	26.1	28.4	61.5	195.0	513.0	"
1946-47							61.6	59.7	64.8	69.5	105.5	237.6	525.7	"
1947-48							105.6	108.4	114.6	116.0	142.7	254.5	536.1	"
1948-49							334.5	331.9	332.0	331.2	354.4	426.7	638.2	"
1949-50							137.3	136.0	138.8	138.7	163.2	263.1	480.1	"
1950-51							56.0	62.4	71.9	72.5	106.9	229.2	511.2	"
1951-52							166.8	166.9	172.9	174.3	201.1	313.2	556.4	"
1952-53							165.6	166.2	171.3	173.3	198.2	291.7	522.6	"
1953-54							5.9	0.0	0.3	2.9	31.5	157.1	453.1	"
1954-55							103.4	105.9	111.0	114.4	139.8	241.9	522.4	"
1955-56							20.3	17.4	22.5	24.1	55.6	203.1	508.9	"
1956-57							117.8	114.1	116.4	118.5	148.6	255.9	573.3	"
1957-58							26.6	26.2	32.9	37.5	69.6	193.9	525.1	"
DISTRIBUTION FACTORS							0.9720	0.9790	0.9740	0.9790	0.9570	0.7580	0.4690	N/A
FORECAST ERRORS (KSFD)							118.4	109.0	97.5	88.1	88.1	73.3	73.3	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	100	100	100	100	100	100	100	100	100	100	100	106	3030	2465
VARIABLE REFILL CURVES					80 MAF		100	500	500	500	1800	1800	2300	3300
(BY VOLUME RUNOFF AT THE DALLES)					95 MAF		100	100	100	100	100	1800	2000	2800
					110 MAF		100	100	100	100	100	1800	2000	2800
VARIABLE REFILL CURVE LOWER LIMITS (KSFD)					80 MAF		190.5	40.6	62.1	81.9	114.8	323.1	555.5	705.8
(BY VOLUME RUNOFF AT THE DALLES)					95 MAF		27.6	18.8	16.9	0.0	33.2	204.6	522.7	705.8
					110 MAF		5.9	0.0	0.3	4.8	2.9	105.5	444.6	705.8
OPERATING RULE CURVE LOWER LIMITS (KSFD)							107.1	42.0	0.0	0.0				

TABLE 7
(English Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2006 - 07 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	3331.6	3238.8	3154.6	3061.8	3061.8	3061.8	3178.6	3529.2	3529.2
1929-30	"	"	"	"	"	"	3182.1	3046.6	2897.2	2897.2	2897.2	3055.2	"	"
1930-31	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3381.0	"	"
1931-32	"	"	"	"	"	"	2699.3	2104.4	1472.2	1472.2	1472.2	2445.1	"	"
1932-33	"	"	"	"	"	"	2691.3	2112.5	"	"	"	2074.9	3093.1	"
1933-34	"	"	"	"	"	"	"	"	"	"	1780.7	2706.4	3529.2	"
1934-35	"	"	"	"	"	"	"	"	"	"	1472.2	2046.1	3093.1	"
1935-36	"	"	"	"	"	"	2699.3	2104.4	"	"	"	2373.1	3529.2	"
1936-37	"	"	"	"	"	"	3136.9	2960.5	2765.8	2765.8	2765.8	3262.0	"	"
1937-38	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	2130.4	3183.6	"
1938-39	"	"	"	"	"	"	2862.1	2438.3	1968.8	1968.8	1968.8	2786.5	3529.2	"
1939-40	"	"	"	"	"	"	3009.7	2708.9	2387.0	2387.0	2387.0	2958.1	"	"
1940-41	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3381.0	"	"
1941-42	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	2212.7	"	"
1942-43	"	"	"	"	"	"	"	"	"	"	1677.9	1883.6	2706.4	"
1943-44	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3381.0	3529.2	"
1944-45	"	"	"	"	"	"	2836.8	2390.0	1895.1	1895.1	1895.1	2506.3	3333.1	"
1945-46	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	2426.6	3529.2	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	2383.4	"	"
1947-48	"	"	"	"	"	"	2699.3	2104.4	"	"	"	2439.0	"	"
1948-49	"	"	"	"	"	"	2691.3	2112.5	"	"	"	2661.1	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	1556.5	2451.3	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	1749.9	3335.9	"
1951-52	"	"	"	"	"	"	2699.3	2104.4	"	"	"	2099.6	3076.7	"
1952-53	"	"	"	"	"	"	2691.3	2112.5	"	"	"	1846.6	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	1967.9	2183.9	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	1988.5	3245.4	"
1955-56	"	"	"	"	"	"	2699.3	2104.4	"	"	1554.5	2295.0	3117.8	"
1956-57	"	"	"	"	"	"	2691.3	2112.5	"	"	1472.2	2786.6	3529.2	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	2459.6	"	"

TABLE 8
(English Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2006 - 07 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	3223.7	3212.6	3202.6	3191.6	3191.6	3191.6	3315.0	3579.6	3579.6
1929-30	"	"	"	"	"	"	3161.0	3104.5	3041.9	3041.9	3041.9	3212.9	"	"
1930-31	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3336.8	"	"
1931-32	"	"	"	"	"	"	2726.5	2261.7	1764.6	1764.6	1764.6	2623.1	"	"
1932-33	"	"	"	"	"	"	2721.0	2267.2	"	"	"	2296.4	3194.8	"
1933-34	"	"	"	"	"	"	"	"	"	"	2312.7	2695.7	3579.6	"
1934-35	"	"	"	"	"	"	"	"	"	"	1764.6	2271.0	3194.8	"
1935-36	"	"	"	"	"	"	2726.5	2261.7	"	"	"	2559.6	3579.6	"
1936-37	"	"	"	"	"	"	3119.9	3026.3	2922.6	2922.6	2922.6	3349.6	"	"
1937-38	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	2345.4	3274.7	"
1938-39	"	"	"	"	"	"	2870.4	2551.3	2198.1	2198.1	2198.1	2922.0	3579.6	"
1939-40	"	"	"	"	"	"	3003.7	2798.4	2578.5	2578.5	2578.5	3079.1	"	"
1940-41	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3336.8	"	"
1941-42	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	2418.0	"	"
1942-43	"	"	"	"	"	"	"	"	"	"	1986.0	2069.5	2739.2	"
1943-44	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3336.8	3579.6	"
1944-45	"	"	"	"	"	"	2848.2	2509.0	2133.5	2133.5	2133.5	2674.4	3406.1	"
1945-46	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	2606.8	3579.6	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	2568.6	"	"
1947-48	"	"	"	"	"	"	2726.5	2261.7	"	"	"	2617.6	"	"
1948-49	"	"	"	"	"	"	2721.0	2267.2	"	"	"	2813.7	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	1839.0	2628.5	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	2009.6	3409.0	"
1951-52	"	"	"	"	"	"	2726.5	2261.7	"	"	"	2318.2	3180.3	"
1952-53	"	"	"	"	"	"	2721.0	2267.2	"	"	"	2094.9	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	2202.0	2392.6	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	2220.2	3329.1	"
1955-56	"	"	"	"	"	"	2726.5	2261.7	"	"	1911.6	2457.9	3165.8	"
1956-57	"	"	"	"	"	"	2721.0	2267.2	"	"	1764.6	2924.4	3579.6	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	2635.8	"	"

TABLE 9
(English Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2006 - 07 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	418.0	340.3	340.3	340.3	340.3	443.3	574.2	705.8
1929-30	"	"	"	"	"	"	408.7	322.6	322.6	322.6	322.6	430.7	567.9	"
1930-31	"	"	"	"	"	"	390.7	288.3	288.3	288.3	288.3	406.1	555.5	"
1931-32	"	"	"	"	"	"	277.3	65.5	65.5	65.5	65.5	281.3	609.8	"
1932-33	"	"	"	"	"	"	273.7	"	"	"	"	191.6	573.3	"
1933-34	"	"	"	"	"	"	"	"	"	"	127.0	339.6	605.3	"
1934-35	"	"	"	"	"	"	"	"	"	"	65.5	187.2	488.1	"
1935-36	"	"	"	"	"	"	277.3	"	"	"	"	351.7	705.8	"
1936-37	"	"	"	"	"	"	378.0	264.1	264.1	264.1	264.1	388.7	546.8	"
1937-38	"	"	"	"	"	"	293.6	103.3	103.3	103.3	103.3	246.1	552.2	"
1938-39	"	"	"	"	"	"	287.7	92.2	92.2	92.2	92.2	399.0	705.8	"
1939-40	"	"	"	"	"	"	303.0	114.9	114.9	114.9	114.9	410.4	"	"
1940-41	"	"	"	"	"	"	345.5	202.1	202.1	202.1	202.1	344.2	524.5	"
1941-42	"	"	"	"	"	"	329.3	171.4	171.4	171.4	171.4	439.6	705.8	"
1942-43	"	"	"	"	"	"	332.5	177.4	177.4	177.4	220.2	288.4	653.0	"
1943-44	"	"	"	"	"	"	416.4	334.7	334.7	334.7	334.7	439.4	572.2	"
1944-45	"	"	"	"	"	"	384.6	276.8	276.8	276.8	276.8	493.4	705.8	"
1945-46	"	"	"	"	"	"	273.7	65.5	65.5	65.5	65.5	322.3	647.5	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	314.0	629.6	"
1947-48	"	"	"	"	"	"	277.3	"	"	"	"	300.5	705.8	"
1948-49	"	"	"	"	"	"	370.9	250.5	250.5	256.4	276.5	434.0	"	"
1949-50	"	"	"	"	"	"	273.7	65.5	65.5	65.5	65.5	184.0	525.3	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	285.1	534.2	"
1951-52	"	"	"	"	"	"	277.3	"	"	"	"	220.4	383.1	"
1952-53	"	"	"	"	"	"	273.7	"	"	"	"	234.6	522.7	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	237.1	547.6	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	154.5	488.8	"
1955-56	"	"	"	"	"	"	277.3	"	"	"	84.7	266.6	585.4	"
1956-57	"	"	"	"	"	"	273.7	"	"	"	65.5	376.0	655.8	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	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)
2006 - 07 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7786.1	7341.2	6900.6	6304.2	5133.8	4088.5	4036.1	4002.2	4042.5	3571.7	5493.0	6991.2	7814.6
1929-30	"	"	"	"	"	"	2943.4	2677.4	2531.0	2564.3	2927.7	4893.8	6707.0	"
1930-31	"	"	"	"	"	"	3392.7	3074.9	2900.1	2921.2	3137.1	4871.9	6782.2	"
1931-32	"	"	"	"	"	"	1954.3	1541.2	1493.8	1489.6	1550.0	3502.2	6376.9	"
1932-33	"	"	"	"	"	"	1858.7	1457.4	1389.2	1375.4	1465.2	3343.9	6127.5	"
1933-34	"	"	"	"	"	"	1043.9	684.2	648.2	648.5	876.6	3681.0	6578.6	"
1934-35	"	"	"	"	"	"	2108.3	1795.4	1835.4	1893.2	2117.2	3906.2	6458.0	"
1935-36	"	"	"	"	"	"	1948.7	1596.4	1658.7	1750.5	1957.5	4221.0	6792.7	"
1936-37	"	"	"	"	"	"	4053.3	3962.2	4002.2	4101.0	3571.7	5489.6	7015.0	"
1937-38	"	"	"	"	"	"	2275.1	2088.3	2020.0	2068.4	2363.8	4264.1	6482.2	"
1938-39	"	"	"	"	"	"	3017.7	2666.9	2569.3	2577.5	2865.7	4836.0	7015.0	"
1939-40	"	"	"	"	"	"	2508.5	2210.8	2185.5	2301.0	2657.0	4838.1	6774.8	"
1940-41	"	"	"	"	"	"	3980.1	3673.9	3602.9	3728.8	3525.5	5445.1	6975.2	"
1941-42	"	"	"	"	"	"	3801.6	3520.9	3408.2	3408.2	3297.6	5031.5	6854.9	"
1942-43	"	"	"	"	"	"	3954.7	3875.5	3414.2	3414.2	3543.6	4241.5	6000.9	"
1943-44	"	"	"	"	"	"	4088.5	4032.8	4002.2	4101.0	3571.7	5506.2	7124.7	"
1944-45	"	"	"	"	"	"	4059.9	3974.9	4002.2	4057.2	3571.7	5427.8	6929.0	"
1945-46	"	"	"	"	"	"	1651.0	1200.8	1135.4	1112.0	1240.3	3205.0	6280.1	"
1946-47	"	"	"	"	"	"	1769.8	1413.2	1376.0	1403.1	1753.6	3899.8	6448.2	"
1947-48	"	"	"	"	"	"	1718.8	1325.2	1289.2	1259.1	1342.4	3403.9	6259.3	"
1948-49	"	"	"	"	"	"	3908.8	3620.9	3458.7	3471.9	3374.5	5488.4	7124.7	"
1949-50	"	"	"	"	"	"	2056.6	1641.2	1554.9	1539.0	1627.4	3495.2	5559.9	"
1950-51	"	"	"	"	"	"	2026.4	1800.1	1771.9	1756.4	2094.1	3988.7	6478.3	"
1951-52	"	"	"	"	"	"	2480.4	2171.6	2099.2	2066.6	2320.1	4339.6	6466.8	"
1952-53	"	"	"	"	"	"	3145.9	2860.7	2792.9	2783.5	2988.0	4176.1	6553.1	"
1953-54	"	"	"	"	"	"	1629.3	1207.8	1147.2	1137.6	1253.2	2991.8	5029.6	"
1954-55	"	"	"	"	"	"	2050.5	1909.9	1885.5	1884.5	2168.1	3864.9	6438.5	"
1955-56	"	"	"	"	"	"	1937.4	1514.4	1447.0	1425.8	1549.1	3573.0	6319.4	"
1956-57	"	"	"	"	"	"	2037.1	1699.2	1554.9	1539.0	1542.4	3554.7	6735.8	"
1957-58	"	"	"	"	"	"	1939.7	1522.3	1487.0	1493.7	1548.7	3417.5	6499.9	"

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

	2001-02	2002-03	2003-04 2004-05 1/	2005-06	2006-07 through 2008-09 2/
MICA TARGET OPERATION					
(ksfd[xxxx.x] or cfs [xxxxx])					
AUG 15	3486.2	3486.2	3499.2	3499.1	3454.2
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	3524.1	FULL
OCT	3396.2	3396.2	3374.1	3344.1	3428.4
NOV	20000	20000	20000	23000	20000.0
DEC	22000	22000	23000	25000	25000.0
JAN	24000	24000	25000	26000	24000.0
FEB	21000	21000	21000	22000	21000.0
MAR	22000	18000	19000	20000	18000.0
APR 15	326.2	281.3	204.1	16000	18000.0
APR 30	56.2	15000	15000	13000	12000.0
MAY	10000	10000	10000	10000	10000.0
JUN	10000	10000	10000	10000	10000.0
JUL	3456.2	3456.2	3449.2	3449.1	3379.2
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (ksfd)					
1928 AUG 31	7806.2	7811.1	7808.9	7678.3	7786.1
1928 DEC	5310.4	5811.1	5213.8	4938.9	5133.8
1929 APR15	1458.7	1452.6	1598.5	927.1	839.3
1929 JUL	7453.0	7426.8	7280.7	7222	7147.7
COMPOSITE CANADIAN TREATY STORAGE CONTENT (ksfd)					
50-yr Average for AOP02, 60-yr average for AOP03~AOP08					
AUG 31	7412.3	7414.6	7415.0	7238.3	7360.7
DEC	5236.9	5226.9	4759.5	4437.3	4634.9
APR15	1135.3	1173.1	1097.7	1085.8	1178.5
JUL	7358.2	7339.0	7262.0	7215.5	7193.7
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	0.2	-0.3	-1.2	-0.1	-0.2
U.S. Dependable Peaking Capacity	0.0	-18.0	16.0	-51.0	-21.0
U.S. Average Annual Usable Secondary Energy	24.9	3.7	12.9	10.5	0.3
BCH Firm Energy	48.3	30.3	43.1	97.7	90.3
BCH Dependable Peaking Capacity	25.0	26.0	8.0	2.0	11.0
BCH Average Annual Usable Secondary Energy	-29.7	-17.3	-24.3	-55.7	-29.3
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	10422	10368	10439	11097	11137
AUG 31	10439	10355	10435	11125	11165
SEP	10434	9911	10101	10809	10849
OCT	10388	10051	10186	9742	9782
NOV	11626	11716	11807	10817	11157
DEC	13012	13160	13377	12853	13192
JAN	13382	13707	13122	12735	13075
FEB	12502	12694	12240	11561	11901
MAR	11667	11858	11175	11275	11315
APR 15	11187	11460	10541	10550	10589
APR 30	12575	13101	13065	14061	12822
MAY	14647	14357	13752	14729	13491
JUN	12590	13324	13114	14039	14079
JUL	10493	10457	12079	12383	12723
ANNUAL AVERAGE	11919	11986	11933	12034	12037

1/ The AOP/DDPB 2004-05 utilize the same system regulation studies as were utilized for the 2003-04 AOP/DDPB.
2/ The AOP/DDPB 2006-07 and 2008-09 utilize the same system regulation studies as were utilized for the 2007-08 AOP/DDPB.

TABLE 1M
(Metric Units)
MICA PROJECT OPERATING CRITERIA
2006-07 ASSURED OPERATING PLAN

	Target Operation			Target Operation Limits		
Month	End of Previous Month Arrow Storage Content (hm³)	Average Outflow (m³/s)	End-of-Month Treaty Storage Content 1/ (hm³)	Minimum Treaty Storage Content 2/ (hm³)	Maximum Outflow 1/ (m³/s)	Minimum Outflow (m³/s)
August 1-15	8,734.4 - FULL	-	8,451.0	-	962.77	424.75
	5,847.4 - 8,734.4	707.92	-	0.0	-	424.75
	0.0 - 5,847.4	906.14	-	0.0	-	424.75
August 16-31	8,734.4 - FULL	-	8,634.5	-	-	424.75
	8,440.8 - 8,734.4	-	8,230.9	-	962.77	424.75
	7,339.8 - 8,440.8	707.92	-	0.0	-	424.75
	0.0 - 7,339.8	906.14	-	0.0	-	424.75
September	8,734.4 - FULL	-	8,634.5	-	-	283.17
	8,294.0 - 8,734.4	622.97	-	0.0	-	283.17
	6,141.0 - 8,294.0	764.55	-	0.0	-	283.17
	0.0 - 6,141.0	906.14	-	0.0	-	283.17
October	8,734.4 - FULL	-	8,387.9	-	962.77	283.17
	7,633.4 - 8,734.4	566.34	-	0.0	-	283.17
	1,835.0 - 7,633.4	622.97	-	0.0	-	283.17
	0.0 - 1,835.0	906.14	-	0.0	-	283.17
November	8,440.8 - FULL	566.34	-	0.0	-	283.17
	7,388.7 - 8,440.8	538.02	-	0.0	-	283.17
	1,541.4 - 7,388.7	707.92	-	0.0	-	283.17
	0.0 - 1,541.4	906.14	-	0.0	-	283.17
December	8,171.6 - FULL	707.92	-	954.4	-	283.17
	7,021.7 - 8,171.6	622.97	-	954.4	-	283.17
	2,201.9 - 7,021.7	764.55	-	954.4	-	283.17
	0.0 - 2,201.9	906.14	-	954.4	-	283.17
January	6,703.7 - FULL	679.60	-	328.1	-	283.17
	6,189.9 - 6,703.7	736.24	-	328.1	-	283.17
	3,988.0 - 6,189.9	792.87	-	328.1	-	283.17
	0.0 - 3,988.0	849.50	-	328.1	-	283.17
February	3,694.4 - FULL	594.65	-	401.5	-	283.17
	3,302.9 - 3,694.4	707.92	-	401.5	-	283.17
	2,789.1 - 3,302.9	566.34	-	401.5	-	283.17
	0.0 - 2,789.1	736.24	-	401.5	-	283.17
March	1,516.9 - FULL	509.70	-	294.3	-	283.17
	1,174.4 - 1,516.9	538.02	-	294.3	-	283.17
	171.3 - 1,174.4	566.34	-	294.3	-	283.17
	0.0 - 171.3	622.97	-	294.3	-	283.17
April 1-15	2,446.6 - FULL	509.70	-	37.4	-	311.49
	2,348.7 - 2,446.6	764.55	-	37.4	-	311.49
	1,883.9 - 2,348.7	339.80	-	37.4	-	311.49
	0.0 - 1,883.9	509.70	-	37.4	-	311.49
April 16-30	2,250.9 - FULL	339.80	-	0.0	-	283.17
	1,198.8 - 2,250.9	424.75	-	0.0	-	283.17
	48.9 - 1,198.8	339.80	-	0.0	-	283.17
	0.0 - 48.9	424.75	-	0.0	-	283.17
May	2,789.1 - FULL	283.17	-	0.0	-	283.17
	1,663.7 - 2,789.1	424.75	-	0.0	-	283.17
	0.0 - 1,663.7	283.17	-	0.0	-	283.17
June	4,452.8 - FULL	283.17	-	0.0	-	283.17
	3,890.1 - 4,452.8	424.75	-	0.0	-	283.17
	2,666.8 - 3,890.1	283.17	-	0.0	-	283.17
	0.0 - 2,666.8	424.75	-	0.0	-	283.17
July	8,171.6 - FULL	-	8,267.6	-	962.77	283.17
	5,504.9 - 8,171.6	-	8,115.9	-	962.77	283.17
	3,718.8 - 5,504.9	538.02	-	0.0	-	283.17
	0.0 - 3,718.8	849.50	-	0.0	-	283.17

1/ If the Mica target end-of-month storage content is less than 8634.5 hm³, then a maximum outflow of 962.77 m³/s will apply.
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)
2006 - 07 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	8634.5	8602.0	8634.5	8322.4	7347.4	5540.8	3724.9	1727.3	1424.4	539.0	79.3	1205.4	5202.2	7382.4
1929-30	8511.7	8145.2	7894.2	5851.0	4778.5	3495.9	1228.9	194.7	0.0	56.0	0.0	901.8	2019.7	6350.2
1930-31	7129.6	7424.0	7626.3	5768.1	4739.6	3136.1	1287.2	183.3	0.0	53.1	0.0	860.0	1842.5	2948.9
1931-32	2940.1	2683.2	1958.0	2572.4	1509.3	60.9	76.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	8757.8	8747.6	7599.6	6965.7	6556.4	5807.2	3449.7	2013.6	1522.5	1332.7	1470.7	3639.1	7439.1	8526.9
1929-30	8249.4	8424.1	6963.0	6695.9	4713.9	3297.5	975.0	204.3	0.0	134.6	449.2	2847.6	6342.6	7464.8
1930-31	7828.6	7866.1	6821.4	6690.0	4892.7	3252.5	1302.8	264.0	0.0	156.1	134.1	2365.1	5127.8	6557.6
1931-32	6562.0	6396.4	5213.5	2982.2	1944.1	943.9	253.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	1726.8	1699.9	1726.8	1594.9	1520.1	1212.3	1010.9	827.0	320.5	181.8	202.3	489.8	1162.1	1578.3
1929-30	1445.2	1599.3	1726.8	1720.0	1309.4	1209.6	845.8	357.0	0.2	29.4	55.8	337.1	784.1	1168.7
1930-31	1177.8	1257.1	1395.5	1386.5	1166.0	836.0	454.8	218.5	0.0	4.9	0.0	204.3	124.0	147.0
1931-32	82.9	114.3	286.7	125.8	177.4	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	19119.2	19049.5	17961.0	16883.0	15423.9	12560.4	8185.6	4567.8	3267.4	2053.4	1752.3	5334.3	13803.5	17487.6
1929-30	18206.4	18168.7	16584.0	14266.9	10801.7	8003.1	3049.7	756.0	0.2	219.9	505.0	4086.6	9146.4	14983.7
1930-31	16136.1	16547.1	15843.2	13844.6	10798.3	7224.6	3044.8	665.7	0.0	214.1	134.1	3429.4	7094.4	9653.5
1931-32	9585.0	9193.8	7458.2	5680.3	3630.8	1005.6	329.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 4M
(Metric Units)
MICA
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, VARIABLE REFILL CURVE LOWER LIMITS, AND OPERATING RULE CURVE LOWER LIMITS
2006 - 07 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	600.9	1981.3	3457.3	3893.5	4053.3	4093.7	4080.9	4053.0	4069.7	4131.3	4084.4	5744.9	8633.6	8634.5
VARIABLE REFILL CURVES (hm^3)														
1928-29							6868.8	6586.2	6490.1	6503.6	6603.4	7693.1	8309.4	8634.5
1929-30							4362.8	3984.0	3864.6	3922.4	4305.3	6207.5	7614.1	"
1930-31							4997.9	4641.0	4510.3	4515.0	4735.4	6256.2	7798.0	"
1931-32							3904.5	3565.4	3450.9	3457.3	3764.1	5536.2	7505.7	"
1932-33							3670.6	3417.9	3345.7	3347.2	3537.0	5284.9	7105.9	"
1933-34							1677.1	1468.7	1383.3	1420.0	1818.1	4669.1	7724.2	"
1934-35							4329.0	4030.5	3988.7	4038.8	4210.4	5787.9	7298.0	"
1935-36							3790.0	3492.5	3422.8	3422.8	3656.0	5651.6	7931.6	"
1936-37							6840.0	6507.0	6374.9	6361.9	6578.9	7726.4	8388.4	"
1937-38							4583.7	4286.0	4171.5	4188.8	4416.1	6082.5	7729.5	"
1938-39							4518.6	4329.0	4232.6	4300.6	4572.9	6313.2	8367.6	"
1939-40							3979.9	3700.7	3646.4	3699.3	4016.1	5810.9	7779.9	"
1940-41							5443.0	5137.1	5054.2	5106.3	5540.1	7178.3	8343.2	"
1941-42							5573.1	5275.8	5172.8	5154.3	5340.4	6815.5	8104.1	"
1942-43							6139.5	5787.2	5677.1	5671.7	6044.8	7617.2	8312.8	"
1943-44							7102.5	6731.1	6632.2	6627.1	6794.7	7986.4	8634.5	"
1944-45							6913.6	6633.0	6567.9	6603.1	6724.0	7808.6	8529.6	"
1945-46							3162.5	2790.1	2671.9	2648.0	2872.3	4792.2	7492.0	"
1946-47							3453.1	3212.4	3164.4	3193.5	3478.3	5439.0	7664.5	"
1947-48							3328.4	3037.0	2951.8	2917.1	3112.6	4938.7	7387.3	"
1948-49							7479.0	7125.2	6974.3	6968.2	7156.8	8304.7	8634.5	"
1949-50							4198.1	3810.1	3667.2	3644.0	3850.7	5479.7	6925.6	"
1950-51							4176.6	3905.3	3840.7	3861.0	4138.7	5771.0	7810.0	"
1951-52							5171.9	4796.3	4669.3	4632.4	4831.3	6493.8	8170.4	"
1952-53							5859.9	5527.8	5424.4	5418.5	5563.8	6873.5	8089.4	"
1953-54							3109.4	2807.2	2763.9	2773.0	2977.5	4733.4	6857.3	"
1954-55							4968.1	4705.3	4641.7	4667.1	4877.8	6313.5	7332.9	"
1955-56							3863.2	3557.4	3443.1	3426.2	3642.5	5521.2	7600.9	"
1956-57							4275.7	3952.0	3873.5	3886.7	4104.4	5732.1	8409.7	"
1957-58							3868.8	3576.7	3514.3	3540.2	3797.4	5479.4	7828.6	"
DISTRIBUTION FACTORS							0.9750	0.9770	0.9740	0.9812	0.9650	0.7950	0.4950	N/A
FORECAST ERRORS (hm^3)							1597.4	1248.5	1138.4	1087.3	1087.3	881.8	881.8	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	240.52	174.63	589.53	1598.94
VARIABLE REFILL CURVES					98.68 km^3		84.95	84.95	84.95	84.95	84.95	84.95	962.77	1132.67
(BY VOLUME RUNOFF AT THE DALLES)					117.18 km^3		84.95	84.95	84.95	84.95	84.95	84.95	962.77	1132.67
					135.69 km^3		84.95	84.95	84.95	84.95	84.95	84.95	962.77	1132.67
VARIABLE REFILL CURVE LOWER LIMITS (hm^3)					98.68 km^3		550.2	590.4	662.5	809.8	1150.1	3574.0	6908.7	8634.5
(By VOLUME RUNOFF AT THE DALLES)					117.18 km^3		96.2	0.0	50.6	66.8	0.0	1668.1	5620.3	8634.5
					135.69 km^3		29.1	0.0	0.0	0.0	9.1	1611.6	4427.1	8634.5
OPERATING RULE CURVE LOWER LIMITS							730.6	86.1	0.0	1.2				

TABLE 5M
(Metric Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, VARIABLE REFILL CURVE LOWER LIMITS, AND OPERATING RULE CURVE LOWER LIMITS
2006 - 07 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
EFILL CURVE (hm^3)														
	0.0	0.0	0.0	103.7	1407.8	3342.8	4911.1	4994.7	5179.2	5327.0	4046.7	6735.0	7226.5	8757.8
EFILL CURVES (hm^3)														
							6103.8	5628.9	5276.3	5183.9	5572.4	6702.7	7436.7	8757.8
							2120.5	1777.2	1784.8	1776.2	2471.1	5236.7	"	"
							3263.8	2764.7	2482.8	2440.5	2983.4	5183.1	"	"
							15.4	0.2	43.5	26.9	30.1	2424.1	6824.8	"
							12.0	0.1	43.1	17.9	23.7	2791.3	6754.3	"
							7.3	0.0	42.3	6.4	15.9	3583.0	7012.4	"
							399.3	201.8	728.4	869.8	1417.8	4092.9	7308.0	"
							365.3	253.0	475.1	699.7	1027.1	3986.7	7328.8	"
							6886.4	6282.4	5927.1	5739.2	6165.4	7151.7	7436.7	"
							1122.3	803.5	1087.5	1205.9	1928.7	4618.2	6798.4	"
							2608.6	2246.2	1990.8	1949.2	2701.3	5183.1	7436.7	"
							1503.7	1427.1	1419.5	1649.3	2203.4	"	"	"
							4811.5	4441.1	4250.7	4497.1	5618.9	7379.9	7657.4	"
							4495.4	4141.8	4407.3	4363.5	4973.9	6506.7	7308.5	"
							5582.9	5061.0	5253.1	5166.7	5456.7	8573.9	8757.8	"
							8124.7	7658.6	7350.1	7185.2	7653.0	8503.9	7877.1	"
							6534.6	6166.2	5947.7	5907.3	6270.4	7215.8	7678.2	"
							5.1	0.0	42.1	0.2	11.7	2572.1	6617.8	"
							355.0	99.1	43.5	79.0	651.8	3520.9	6825.5	"
							4.9	0.0	42.1	0.0	11.5	2766.6	6615.1	"
							4664.0	4193.0	4445.2	4428.3	5121.7	6691.5	7904.2	"
							4.9	0.0	42.1	0.0	219.5	4293.0	6615.1	"
							465.3	346.2	573.0	535.1	1361.3	4939.7	6789.1	"
							1579.5	1099.7	1373.8	1294.0	1914.2	4941.2	7356.9	"
							3210.7	2785.7	3071.0	3048.0	3548.3	6237.6	7226.8	"
							4.9	0.0	42.1	0.0	11.5	2201.9	7074.8	"
							673.8	459.5	850.9	848.5	1542.3	4212.8	7223.6	"
							4.9	0.0	42.1	0.0	11.5	2723.6	6615.1	"
							"	"	"	"	"	2338.7	6711.5	"
							13.7	0.2	43.3	22.5	26.9	2407.5	6789.3	"
ON FACTORS							0.9710	0.9747	0.9691	0.9741	0.9530	0.7483	0.4631	N/A
ERRORS (hm^3)							3016.9	2415.5	2019.2	1749.6	1749.6	1226.7	1226.7	N/A
CHARGE REQUIREMENTS (m^3/s):														
REFILL CURVE														
	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	1604.52	304.72	1941.97	1936.45
REFILL CURVES					98.68 km^3		141.58	141.58	141.58	141.58	226.53	226.53	1415.84	1415.84
LUME RUNOFF AT THE DALLES)					117.18 km^3		141.58	141.58	141.58	141.58	141.58	141.58	1415.84	1415.84
					135.69 km^3		141.58	141.58	141.58	141.58	141.58	141.58	1415.84	1415.84
EFILL CURVE LOWER LIMITS (hm^3)					98.68 km^3		339.3	518.4	925.8	1353.0	2038.0	5183.1	7436.7	8757.8
ME RUNOFF AT THE DALLES)					117.18 km^3		35.7	0.5	46.2	78.5	65.3	2848.8	7226.0	8757.8
					135.69 km^3		4.9	0.0	42.1	0.0	11.5	2201.9	6615.1	8757.8
RULE CURVE LOWER LIMITS (hm^3)							614.8	45.0	0.0	3.2				

TABLE 6M
(Metric Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, VARIABLE REFILL CURVE LOWER LIMITS, AND OPERATING RULE CURVE LOWER LIMITS
2006 - 07 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	0.0	153.4	315.6	390.7	433.5	460.9	485.9	508.4	542.9	575.2	607.5	991.6	1358.6	1726.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							1195.7	1158.5	1120.8	1102.7	1087.8	1190.5	1524.5	1726.8
1929-30							1191.7	1153.6	1115.2	1096.3	1116.1	1240.7	1552.6	"
1930-31							1056.0	1021.0	991.4	984.8	983.8	1117.1	1524.5	"
1931-32							190.1	185.7	204.5	224.4	328.6	608.2	1271.3	"
1932-33							26.4	10.5	10.0	0.0	24.0	313.4	1131.3	"
1933-34							166.4	203.8	235.6	270.1	442.8	753.8	1413.4	"
1934-35							462.4	462.7	477.3	479.0	513.5	749.1	1310.2	"
1935-36							362.8	346.7	333.5	328.1	363.3	688.7	1366.7	"
1936-37							1068.2	1030.8	997.5	978.6	963.7	1098.8	1480.7	"
1937-38							363.1	376.5	389.7	407.6	483.0	743.3	1331.4	"
1938-39							693.6	672.3	648.1	638.8	656.9	903.8	1482.4	"
1939-40							653.7	644.7	638.6	652.8	674.8	908.9	1454.3	"
1940-41							853.6	837.7	821.3	838.7	882.5	1095.8	1512.5	"
1941-42							724.7	731.0	734.0	738.6	779.7	980.6	1440.1	"
1942-43							683.6	685.3	694.1	699.0	776.1	1011.9	1412.2	"
1943-44							1236.3	1211.1	1185.4	1172.2	1162.6	1270.5	1598.4	"
1944-45							1025.9	1005.8	985.0	973.3	963.5	1092.7	1491.7	"
1945-46							61.4	55.5	63.9	69.5	150.5	477.1	1255.1	"
1946-47							150.7	146.1	158.5	170.0	258.1	581.3	1286.2	"
1947-48							258.4	265.2	280.4	283.8	349.1	622.7	1311.6	"
1948-49							818.4	812.0	812.3	810.3	867.1	1044.0	1561.4	"
1949-50							335.9	332.7	339.6	339.3	399.3	643.7	1174.6	"
1950-51							137.0	152.7	175.9	177.4	261.5	560.8	1250.7	"
1951-52							408.1	408.3	423.0	426.4	492.0	766.3	1361.3	"
1952-53							405.2	406.6	419.1	424.0	484.9	713.7	1278.6	"
1953-54							14.4	0.0	0.7	7.1	77.1	384.4	1108.6	"
1954-55							253.0	259.1	271.6	279.9	342.0	591.8	1278.1	"
1955-56							49.7	42.6	55.0	59.0	136.0	496.9	1245.1	"
1956-57							288.2	279.2	284.8	289.9	363.6	626.1	1402.6	"
1957-58							65.1	64.1	80.5	91.7	170.3	474.4	1284.7	"
DISTRIBUTION FACTORS							0.9720	0.9790	0.9740	0.9790	0.9570	0.7580	0.4690	N/A
FORECAST ERRORS (hm^3)							289.7	266.7	238.5	215.5	215.5	179.3	179.3	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	3.00	85.80	69.80
VARIABLE REFILL CURVES					98.68 km^3		2.83	14.16	14.16	14.16	50.97	50.97	65.13	93.45
(BY VOLUME RUNOFF AT THE DALLES)					117.18 km^3		2.83	2.83	2.83	2.83	2.83	50.97	56.63	79.29
					135.69 km^3		2.83	2.83	2.83	2.83	2.83	50.97	56.63	79.29
VARIABLE REFILL CURVE LOWER LIMITS (hm^3)					98.68 km^3		466.1	99.3	151.9	200.4	280.9	790.5	1359.1	1726.8
(By VOLUME RUNOFF AT THE DALLES)					117.18 km^3		67.5	46.0	41.3	0.0	81.2	500.6	1278.8	1726.8
					135.69 km^3		14.4	0.0	0.7	11.7	7.1	258.1	1087.8	1726.8
OPERATING RULE CURVE LOWER LIMITS (hm^3)							262.0	102.8	0.0	0.0				

TABLE 7M
(Metric Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2006 - 07 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	8151.1	7924.0	7718.0	7491.0	7491.0	7491.0	7776.8	8634.5	8634.5
1929-30	"	"	"	"	"	"	7785.3	7453.8	7088.3	7088.3	7088.3	7474.9	"	"
1930-31	"	"	"	"	"	"	8151.1	8151.1	8151.1	8151.1	8151.1	8272.0	"	"
1931-32	"	"	"	"	"	"	6604.1	5148.6	3601.9	3601.9	3601.9	5982.2	"	"
1932-33	"	"	"	"	"	"	6584.5	5168.4	"	"	"	5076.5	7567.6	"
1933-34	"	"	"	"	"	"	"	"	"	"	4356.7	6621.5	8634.5	"
1934-35	"	"	"	"	"	"	"	"	"	"	3601.9	5006.0	7567.6	"
1935-36	"	"	"	"	"	"	6604.1	5148.6	"	"	"	5806.0	8634.5	"
1936-37	"	"	"	"	"	"	7674.7	7243.2	6766.8	6766.8	6766.8	7980.8	"	"
1937-38	"	"	"	"	"	"	6584.5	5168.4	3601.9	3601.9	3601.9	5212.2	7789.0	"
1938-39	"	"	"	"	"	"	7002.4	5965.5	4816.9	4816.9	4816.9	6817.5	8634.5	"
1939-40	"	"	"	"	"	"	7363.5	6627.6	5840.0	5840.0	5840.0	7237.3	"	"
1940-41	"	"	"	"	"	"	8151.1	8151.1	8151.1	8151.1	8151.1	8272.0	"	"
1941-42	"	"	"	"	"	"	6584.5	5168.4	3601.9	3601.9	3601.9	5413.6	"	"
1942-43	"	"	"	"	"	"	"	"	"	"	4105.2	4608.4	6621.5	"
1943-44	"	"	"	"	"	"	8151.1	8151.1	8151.1	8151.1	8151.1	8272.0	8634.5	"
1944-45	"	"	"	"	"	"	6940.5	5847.4	4636.6	4636.6	4636.6	6131.9	8154.8	"
1945-46	"	"	"	"	"	"	6584.5	5168.4	3601.9	3601.9	3601.9	5936.9	8634.5	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	5831.2	"	"
1947-48	"	"	"	"	"	"	6604.1	5148.6	"	"	"	5967.3	"	"
1948-49	"	"	"	"	"	"	6584.5	5168.4	"	"	"	6510.6	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	3808.1	5997.4	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	4281.3	8161.6	"
1951-52	"	"	"	"	"	"	6604.1	5148.6	"	"	"	5136.9	7527.5	"
1952-53	"	"	"	"	"	"	6584.5	5168.4	"	"	"	4517.9	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	4814.7	5343.1	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	4865.1	7940.2	"
1955-56	"	"	"	"	"	"	6604.1	5148.6	"	"	3803.2	5614.9	7628.0	"
1956-57	"	"	"	"	"	"	6584.5	5168.4	"	"	3601.9	6817.7	8634.5	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	6017.7	"	"

TABLE 8M
(Metric Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2006 - 07 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	7887.1	7859.9	7835.5	7808.6	7808.6	7808.6	8110.5	8757.8	8757.8
1929-30	"	"	"	"	"	"	7733.7	7595.5	7442.3	7442.3	7442.3	7860.7	"	"
1930-31	"	"	"	"	"	"	7887.1	7887.1	7887.1	7887.1	7887.1	8163.8	"	"
1931-32	"	"	"	"	"	"	6670.7	5533.5	4317.3	4317.3	4317.3	6417.7	"	"
1932-33	"	"	"	"	"	"	6657.2	5546.9	"	"	"	5618.4	7816.4	"
1933-34	"	"	"	"	"	"	"	"	"	"	5658.3	6595.3	8757.8	"
1934-35	"	"	"	"	"	"	"	"	"	"	4317.3	5556.2	7816.4	"
1935-36	"	"	"	"	"	"	6670.7	5533.5	"	"	"	6262.3	8757.8	"
1936-37	"	"	"	"	"	"	7633.1	7404.1	7150.4	7150.4	7150.4	8195.1	"	"
1937-38	"	"	"	"	"	"	6657.2	5546.9	4317.3	4317.3	4317.3	5738.3	8011.9	"
1938-39	"	"	"	"	"	"	7022.7	6242.0	5377.9	5377.9	5377.9	7149.0	8757.8	"
1939-40	"	"	"	"	"	"	7348.9	6846.6	6308.6	6308.6	6308.6	7533.3	"	"
1940-41	"	"	"	"	"	"	7887.1	7887.1	7887.1	7887.1	7887.1	8163.8	"	"
1941-42	"	"	"	"	"	"	6657.2	5546.9	4317.3	4317.3	4317.3	5915.9	"	"
1942-43	"	"	"	"	"	"	"	"	"	"	4858.9	5063.2	6701.7	"
1943-44	"	"	"	"	"	"	7887.1	7887.1	7887.1	7887.1	7887.1	8163.8	8757.8	"
1944-45	"	"	"	"	"	"	6968.4	6138.5	5219.8	5219.8	5219.8	6543.2	8333.4	"
1945-46	"	"	"	"	"	"	6657.2	5546.9	4317.3	4317.3	4317.3	6377.8	8757.8	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	6284.3	"	"
1947-48	"	"	"	"	"	"	6670.7	5533.5	"	"	"	6404.2	"	"
1948-49	"	"	"	"	"	"	6657.2	5546.9	"	"	"	6884.0	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	4499.3	6430.9	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	4916.7	8340.5	"
1951-52	"	"	"	"	"	"	6670.7	5533.5	"	"	"	5671.7	7780.9	"
1952-53	"	"	"	"	"	"	6657.2	5546.9	"	"	"	5125.4	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	5387.4	5853.7	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	5431.9	8145.0	"
1955-56	"	"	"	"	"	"	6670.7	5533.5	"	"	4676.9	6013.5	7745.4	"
1956-57	"	"	"	"	"	"	6657.2	5546.9	"	"	4317.3	7154.8	8757.8	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	6448.7	"	"

TABLE 9M
(Metric Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2006 - 07 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	1022.7	832.6	832.6	832.6	832.6	1084.6	1404.8	1726.8
1929-30	"	"	"	"	"	"	999.9	789.3	789.3	789.3	789.3	1053.8	1389.4	"
1930-31	"	"	"	"	"	"	955.9	705.4	705.4	705.4	705.4	993.6	1359.1	"
1931-32	"	"	"	"	"	"	678.4	160.3	160.3	160.3	160.3	688.2	1491.9	"
1932-33	"	"	"	"	"	"	669.6	"	"	"	"	468.8	1402.6	"
1933-34	"	"	"	"	"	"	"	"	"	"	310.7	830.9	1480.9	"
1934-35	"	"	"	"	"	"	"	"	"	"	160.3	458.0	1194.2	"
1935-36	"	"	"	"	"	"	678.4	"	"	"	"	860.5	1726.8	"
1936-37	"	"	"	"	"	"	924.8	646.1	646.1	646.1	646.1	951.0	1337.8	"
1937-38	"	"	"	"	"	"	718.3	252.7	252.7	252.7	252.7	602.1	1351.0	"
1938-39	"	"	"	"	"	"	703.9	225.6	225.6	225.6	225.6	976.2	1726.8	"
1939-40	"	"	"	"	"	"	741.3	281.1	281.1	281.1	281.1	1004.1	"	"
1940-41	"	"	"	"	"	"	845.3	494.5	494.5	494.5	494.5	842.1	1283.2	"
1941-42	"	"	"	"	"	"	805.7	419.3	419.3	419.3	419.3	1075.5	1726.8	"
1942-43	"	"	"	"	"	"	813.5	434.0	434.0	434.0	538.7	705.6	1597.6	"
1943-44	"	"	"	"	"	"	1018.8	818.9	818.9	818.9	818.9	1075.0	1399.9	"
1944-45	"	"	"	"	"	"	941.0	677.2	677.2	677.2	677.2	1207.2	1726.8	"
1945-46	"	"	"	"	"	"	669.6	160.3	160.3	160.3	160.3	788.5	1584.2	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	768.2	1540.4	"
1947-48	"	"	"	"	"	"	678.4	"	"	"	"	735.2	1726.8	"
1948-49	"	"	"	"	"	"	907.4	612.9	612.9	627.3	676.5	1061.8	"	"
1949-50	"	"	"	"	"	"	669.6	160.3	160.3	160.3	160.3	450.2	1285.2	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	697.5	1307.0	"
1951-52	"	"	"	"	"	"	678.4	"	"	"	"	539.2	937.3	"
1952-53	"	"	"	"	"	"	669.6	"	"	"	"	574.0	1278.8	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	580.1	1339.8	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	378.0	1195.9	"
1955-56	"	"	"	"	"	"	678.4	"	"	"	207.2	652.3	1432.2	"
1956-57	"	"	"	"	"	"	669.6	"	"	"	160.3	919.9	1604.5	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	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)
2006 - 07 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.2	19049.5	17961.0	16883.0	15423.9	12560.4	10002.9	9874.7	9791.8	9890.4	8738.5	13439.2	17104.7	19119.2
1929-30	"	"	"	"	"	"	7201.3	6550.5	6192.3	6273.8	7162.9	11973.2	16409.3	"
1930-31	"	"	"	"	"	"	8300.6	7523.1	7095.4	7147.0	7675.2	11919.6	16593.3	"
1931-32	"	"	"	"	"	"	4781.4	3770.7	3654.7	3644.5	3792.2	8568.5	15601.7	"
1932-33	"	"	"	"	"	"	4547.5	3565.7	3398.8	3365.1	3584.8	8181.2	14991.5	"
1933-34	"	"	"	"	"	"	2554.0	1674.0	1585.9	1586.6	2144.7	9005.9	16095.2	"
1934-35	"	"	"	"	"	"	5158.2	4392.6	4490.5	4631.9	5179.9	9556.9	15800.1	"
1935-36	"	"	"	"	"	"	4767.7	3905.8	4058.2	4282.8	4789.2	10327.1	16619.0	"
1936-37	"	"	"	"	"	"	9916.8	9693.9	9791.8	10033.5	8738.5	13430.9	17162.9	"
1937-38	"	"	"	"	"	"	5566.3	5109.2	4942.1	5060.5	5783.3	10432.5	15859.4	"
1938-39	"	"	"	"	"	"	7383.1	6524.8	6286.0	6306.1	7011.2	11831.8	17162.9	"
1939-40	"	"	"	"	"	"	6137.3	5408.9	5347.0	5629.6	6500.6	11836.9	16575.2	"
1940-41	"	"	"	"	"	"	9737.7	8988.6	8814.9	9122.9	8625.5	13322.0	17065.5	"
1941-42	"	"	"	"	"	"	9301.0	8614.2	8338.5	8338.5	8067.9	12310.1	16771.2	"
1942-43	"	"	"	"	"	"	9675.6	9481.8	8353.2	8353.2	8669.8	10377.3	14681.8	"
1943-44	"	"	"	"	"	"	10002.9	9866.6	9791.8	10033.5	8738.5	13471.5	17431.3	"
1944-45	"	"	"	"	"	"	9933.0	9725.0	9791.8	9926.3	8738.5	13279.7	16952.5	"
1945-46	"	"	"	"	"	"	4039.3	2937.9	2777.9	2720.6	3034.5	7841.4	15364.9	"
1946-47	"	"	"	"	"	"	4330.0	3457.5	3366.5	3432.8	4290.4	9541.3	15776.2	"
1947-48	"	"	"	"	"	"	4205.2	3242.2	3154.2	3080.5	3284.3	8328.0	15314.0	"
1948-49	"	"	"	"	"	"	9563.3	8858.9	8462.1	8494.4	8256.1	13427.9	17431.3	"
1949-50	"	"	"	"	"	"	5031.7	4015.4	3804.2	3765.3	3981.6	8551.4	13602.9	"
1950-51	"	"	"	"	"	"	4957.8	4404.1	4335.1	4297.2	5123.4	9758.8	15849.8	"
1951-52	"	"	"	"	"	"	6068.5	5313.0	5135.9	5056.1	5676.4	10617.3	15821.7	"
1952-53	"	"	"	"	"	"	7696.8	6999.0	6833.1	6810.1	7310.4	10217.2	16032.8	"
1953-54	"	"	"	"	"	"	3986.2	2955.0	2806.7	2783.3	3066.1	7319.7	12305.4	"
1954-55	"	"	"	"	"	"	5016.8	4672.8	4613.1	4610.6	5304.5	9455.9	15752.4	"
1955-56	"	"	"	"	"	"	4740.0	3705.1	3540.2	3488.4	3790.0	8741.7	15461.0	"
1956-57	"	"	"	"	"	"	4984.0	4157.3	3804.2	3765.3	3773.6	8696.9	16479.8	"
1957-58	"	"	"	"	"	"	4745.7	3724.5	3638.1	3654.5	3789.0	8361.3	15902.7	"

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

	2001-02	2002-03	2003-04 2004-05 1/	2005-06	2006-07 through 2008-09 2/
MICA TARGET OPERATION					
(hm³ [xxxx.x] or m³/s [xxxx.xx])					
AUG 15	8529.3	8529.3	8561.1	8560.9	8451.0
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	8622.1	FULL
OCT	8309.1	8309.1	8255.1	8181.7	8387.9
NOV	566.34	566.34	566.34	651.29	566.34
DEC	622.97	622.97	651.29	707.92	707.92
JAN	679.60	679.60	707.92	736.24	679.60
FEB	594.65	594.65	594.65	622.97	594.65
MAR	622.97	509.70	538.02	566.34	509.70
APR 15	798.1	688.2	499.4	453.07	509.70
APR 30	137.5	424.75	424.75	368.12	339.80
MAY	283.17	283.17	283.17	283.17	283.17
JUN	283.17	283.17	283.17	283.17	283.17
JUL	8455.9	8455.9	8438.8	8438.6	8267.6
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (hm³)					
1928 AUG 31	19098.6	19110.6	19105.3	18785.7	19049.5
1928 DEC	12992.4	14217.4	12756.1	12083.5	12560.4
1929 APR15	3568.9	3553.9	3910.9	2268.2	2053.4
1929 JUL	18234.5	18170.4	17813.0	17669.3	17487.6
COMPOSITE CANADIAN TREATY STORAGE CONTENT (hm³)					
50-yr Average for AOP02, 60-yr average for AOP03~AOP08					
AUG 31	18134.9	18140.6	18141.5	17709.2	18008.7
DEC	12812.6	12788.1	11644.6	10856.3	11339.7
APR15	2777.6	2870.1	2685.6	2656.5	2883.3
JUL	18002.6	17955.6	17767.2	17653.4	17600.1
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	0.2	-0.3	-1.2	-0.08	-0.2
U.S. Dependable Peaking Capacity	0.0	-18.0	16.0	-51	-21.0
U.S. Average Annual Usable Secondary Energy	24.9	3.7	12.9	10.5	0.3
BCH Firm Energy	48.3	30.3	43.1	97.68	90.3
BCH Dependable Peaking Capacity	25.0	26.0	8.0	2	11.0
BCH Average Annual Usable Secondary Energy	-29.7	-17.3	-24.3	-55.72	-29.3
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	10422	10368	10439	11097	11137
AUG 31	10439	10355	10435	11125	11165
SEP	10434	9911	10101	10809	10849
OCT	10388	10051	10186	9742	9782
NOV	11626	11716	11807	10817	11157
DEC	13012	13160	13377	12853	13192
JAN	13382	13707	13122	12735	13075
FEB	12502	12694	12240	11561	11901
MAR	11667	11858	11175	11275	11315
APR 15	11187	11460	10541	10550	10589
APR 30	12575	13101	13065	14061	12822
MAY	14647	14357	13752	14729	13491
JUN	12590	13324	13114	14039	14079
JUL	10493	10457	12079	12383	12723
ANNUAL AVERAGE	11919	11986	11933	11933	12037

1/ The 2004-05 AOP/DDPB utilize the same system regulation studies as were utilized for the 2003-04 AOP/DDPB.

2/ The AOP/DDPB 2006-07 and 2008-09 utilize the same system regulation studies as were utilized for the 2007-08 AOP/DDPB.

Appendix A1
(English Units)
Project Operating Procedures for the 2006- 07
Assured Operating Plan and Determination of Downstream Power Benefits

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

Project Name (Number)	Constraint Type	Requirements			Source
Canadian Projects					
Mica (1890)	Minimum Flow	3000 cfs			In place in AOP79, AOP80, AOP84
Arrow (1831)	Minimum Flow	5000 cfs			In place in AOP79, AOP80, AOP84
	Draft Limit		1.0 ft/day		
Duncan (1681)	Minimum Flow	100 cfs			In place in AOP79, AOP80, AOP84
	Maximum Flow	10000 cfs			In place in AOP79, AOP80, AOP84
	Draft Limit		1.0 ft/day		
	Other			Operate to meet IJC orders for Corra Linn	CRTOC agreement on procedures to implement 1938 IJC order
Base System					
Hungry Horse (1530)	Minimum Flow	400 cfs		Minimum project discharge	In place in AOP79, AOP80, AOP84
	Maximum Flow			None	
	Minimum Content			None	
	Other			No VECC limit	VECC limit not in place in AOP79
Kerr (1510)	Minimum Flow	1500 cfs		All periods	In place in AOP80, AOP84
	Maximum Flow			None	
	Minimum Content	614.7 ksfd 426.3 ksfd	2893.0 ft 2890.0 ft	Jun - Sep May	MPC 2-1-92, PNCA submittal similar operation, Jun-Aug 15, in AOP80
		0.0 ksfd	2883.0 ft	Empty Apr 15	FERC, AOP80
	Maximum Content	**58.6 ksfd**	**2884.0 ft**	March (Included to help meet the Apr 15 FERC requirement.)	In place in AOP80, and AOP84
	Other	0.0 ksfd	2883.0 ft	Conditions permitted, should be on or about, empty Mar and Apr 15.	FERC, AOP80
Thompson Falls (1490)				None Noted	
Noxon Rapids (1480)	Minimum Content For Step I:	116.3 ksfd 112.3 ksfd 78.7 ksfd 26.5 ksfd 0.0 ksfd	2331.0 ft 2330.0 ft 2321.0 ft 2305.0 ft 2295.0 ft	May - Aug 31, Sep - Jan, Feb, Mar, Empty Apr 15, Apr 30, and for end of CP.	In place in AOP84, similar operation in AOP80
	Minimum & Maximum Content For Steps II & III:	116.3 ksfd	2331.0 ft	All periods	In place in AOP79, AOP84

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

Project Name (Number)	Constraint Type	Requirements			Source
Cabinet Gorge (1475)				None Noted	
Albeni Falls (1465)	Minimum Flow	4000 cfs		All periods	In place in AOP80, AOP84
	Minimum Content	(Dec may fill on restriction, note below)			
		582.4 ksfd	2062.5 ft	Jun - Aug 31	In place in AOP80, AOP84
		465.7 ksfd	2060.0 ft	Sep	
		190.4 ksfd	2054.0 ft	Oct	
		57.6 ksfd	2051.0 ft	Nov-Apr 15	
		190.4 ksfd	2054.0 ft	Apr 30 (empty at end of CP)	
		279.0 ksfd	2056.0 ft	May	
	For Steps I & II:	Optimum to run CP & LT to Jun-Oct SMINs.			
	For Step III:	Keep full at beginning of CP. Often (not always) optimum to run higher than SMIN in CP & LT (except when occasionally drafting below SMIN to meet load).			
		57.6 ksfd	2051.0 ft	Nov - Mar	
		458.4 ksfd	2059.8 ft	May	
		582.4 ksfd	2062.5 ft	Sep	
		465.7 ksfd	2060.0 ft	Oct	
	Kokanee Spawning	Draft no more than 1 ft below Nov 20 elevation through Dec 31. If project fills, draft no more than 0.5 ft. Dec 31 - Mar 31 operate between SMIN and URC within above noted draft limits.			In place before AOP80 and supported by minimum contents noted above.
	Other Spill	50 cfs		All periods	
Box Canyon (1460)				None Noted	
Grand Coulee (1280)	Minimum Flow	30000 cfs		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	0.0 ksfd	1208.0 ft	Empty at end of CP	
	Step I only:	843.9 ksfd	1240.0 ft	May and June	Retain as a power operation (for pumping)
	Steps II & III only:	857.9 ksfd	1240.0 ft	May and June	
	Maximum Content				
	Step I only:		2.0 ft	Operating room Sep - Nov	In place in AOP89. Retain as a power operation
			3.0 ft	Operating room Dec - Feb	
	Steps II & III only:	2557.1 ksfd	1288.0 ft	Aug-Nov	
		2518.3 ksfd	1287.0 ft	Dec-Feb	
	Draft Limit		1.3 ft/day	(bank sloughage)	
			1.5 ft/day	(Constraint submitted as 1.5 ft/day interpreted as 1.3 ft/day mo.ave.)	
Chief Joseph (1270)	Other Spill	500 cfs		All periods	
Wells (1220)	Other Spill	1200 cfs		All periods	With fish ladder
	Fish Spill			None	
Rocky Reach (1200)	Fish Spill/Bypass			None	
	Other Spill	200 cfs		Aug 31 - Apr 15 (leakage)	
Rock Island (1170)	Fish Spill/Bypass			None	
Wanapum (1165)	Fish Spill/Bypass			None	
	Other Spill	2200 cfs		All periods	With fish ladder

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

Project Name (Number)	Constraint Type	Requirements			Source
Priest Rapids (1160)	Minimum Flow			Limit removed	
	Fish Spill/Bypass			None	
	Other Spill	2200 cfs		All periods	With fish ladder
Brownlee (767)	Minimum Flow	5000 cfs		Variable flow	In place in AOP79, AOP80, AOP84
	Power Operation			Agree to use "old" power operation (first codes) provided by IPC and used in AOP since AOP97 for CP	2-1-91 PNCA submittal
				LT run to PDP using rule curves from CP with BECC created from regulation spreadsheet to meet flow requirements at Lime Pt., and Brownlee and mimic the "old" historic first code operation on a 60 year average and median comparison. Consistent w/ TSR	7-00 J. Hyde
Oxbow (765)	Other Spill	100 cfs		All periods	
Ice Harbor (502)	Fish Spill/Bypass			None	
	Other Spill	740 cfs		All periods	
	Incremental Spill			None	
	Minimum Flow			None	
	Other	204.8 ksfd	440.0 ft	Run at all periods	
McNary (488)	Other Spill	3475 cfs		All periods	
	Incremental Spill			None	
John Day (440)	Fish Spill/Bypass			None	
	Other Spill	800 cfs		All periods	
	Incremental Spill			None	
	Minimum Flow	50000 cfs 12500 cfs		Mar - Nov Dec - Feb	
	Other Step I:	269.7 ksfd 242.5 ksfd 153.7 ksfd 114.9 ksfd	268.0 ft 267.0 ft 263.6 ft 262.0 ft	June - Aug 15 Aug 31 - Sep Oct - Mar Apr - May	In place AOP80
	Steps II & III:	190.0 ksfd	265.0 ft	Use JDA as run-of-river plant.	
The Dalles (365)	Fish Spill/Bypass			None	
	Other Spill	1300 cfs		All periods	
	Incremental Spill			None	
	Minimum Flow	50000 cfs 12500 cfs		Mar - Nov Dec - Feb	
Bonneville (320)	Fish Spill/Bypass			None	
	Other Spill	8040 cfs		All periods	
	Incremental Spill			None	

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

Project Name (Number)	Constraint Type	Requirements			Source
Kootenay Lake (Corra Linn (1665))	Minimum Flow	5000 cfs		All periods	BCHydro agreements 1969
	Other			Operate to IJC orders.	CRTOC agreement on procedures to implement 1938 IJC order
Chelan (1210)	Minimum Flow	50 cfs		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	308.5 **ksfd**	1098.0 ft	Jul - Sep (except as needed to empty at end of critical period).	In place in AOP79, AOP80, AOP84
Couer d'Alene L (1341)	Minimum Flow	50 cfs		All periods	In place in AOP79
	Minimum Content	112.5 **ksfd**	2128.0 ft	May - Aug	
Post Falls (1340)	Minimum Flow	50 cfs		All periods	In place in AOP79, AOP80, AOP84
Other Major Step I Projects					
Libby (1760)	Minimum Flow	4000 cfs		All periods	
	Other Spill	200 cfs		All periods	
	Minimum Content	By contract year: Aug-Jul i.e., 1929 = Aug 1928 - Jul 1929			
		776.9 ksfd	2363.0 ft	1929 Dec	2-1-93 PNCA submittal, in place in AOP99
		676.5 ksfd	2355.0 ft	1929 Jan	
		603.6 ksfd	2349.0 ft	1929 Feb	
		2147.7 ksfd	2443.0 ft	1929 Jul	
		652.0 ksfd	2353.0 ft	1930 Dec	
		433.2 ksfd	2334.0 ft	1930 Jan	
		389.3 ksfd	2330.0 ft	1930 Feb	
		348.5 ksfd	2326.0 ft	1930 Mar	
		297.4 ksfd	2321.0 ft	1930 Apr 15	
		444.2 ksfd	2335.0 ft	1930 Apr 30	
		499.1 ksfd	2340.0 ft	1930 May	
		1344.6 ksfd	2402.0 ft	1930 Jun	
		1771.9 ksfd	2425.0 ft	1930 Jul	
		317.8 ksfd	2323.0 ft	1931 Dec	
		192.2 ksfd	2310.0 ft	1931 Jan	
		103.1 ksfd	2300.0 ft	1931 Feb-Apr 30	
		192.2 ksfd	2310.0 ft	1931 May	
		676.5 ksfd	2355.0 ft	1931 Jun	
		868.0 ksfd	2370.0 ft	1931 Jul	
		174.4 ksfd	2308.0 ft	1932 Dec	
		103.1 ksfd	2300.0 ft	1932 Jan	
		0.0 ksfd	2287.0 ft	Empty at end of CP***	
		776.9 ksfd	2363.0 ft	All Dec	
		July 1930 - No more than 373.1 ksfd lower than July 1929 July 1931 - No more than 857.1 ksfd lower than July 1930 March - Implement PNCA 6(c)2(c).			2-1-94 PNCA submittal, in place in AOP00 and AOP01
	Max Summer Draft		5.0 ft		
	Other			Operate to meet IJC orders for Corra Linn	CRTOC agreement on procedures to implement 1938 IJC order

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

Project Name (Number)	Constraint Type	Requirements					Source
Dworshak (535)	Minimum Flow	1300 cfs			All periods		2-11-02 PNCA submittal
	Maximum Flow	14000 cfs			All periods (model includes maximum 14000 cfs for all periods, but URC may override.)		2-11-02 PNCA submittal
		25000 cfs			Up to 25 kcfs for flood control all periods.		
	Minimum Content	395.8 ksfd		1520.0 ft	SMIN Apr - Aug 31		
	Start 3 yr CP at:	395.8 ksfd		1520.0 ft	Aug 15		
	End 3 yr CP at:	218.4 ksfd		1490.2 ft	Feb		
	Other	Run on minimum flow or flood control observing maximum & minimum flow requirements Sep-Jun and meets LWG Target flows Jul- Aug31 (based on sliding scale).					2-11-02 PNCA submittal
	LWG Target Flow	50000 cfs	to	55000 cfs	Jul - Aug 31		2-11-02 PNCA submittal
	Other Spill	100 cfs			All periods		
Lower Granite (520)	Bypass Date				None		
	Other Spill	670 cfs			All periods		
	Incremental Spill				Removed		
	Fish Spill	(only if regulated flow ≥ 85000 cfs)					2-11-02 PNCA submittal
		16467 cfs			Apr 15	[19000*13/15]	
		19000 cfs			Apr 30 & May		
		12667 cfs			Jun	[19000*20/30]	
	Maximum Fish Spill	19000 cfs					
	Minimum Flow	11500 cfs			Mar-Nov		
	Other	224.9 ksfd		733.0 ft	On MOP Apr - Oct 31		
		245.8 ksfd		738.0 ft	On full pool Nov 30 - Mar 31.		
Little Goose (518)	Bypass Date				None		
	Other Spill	630 cfs			All periods		
	Incremental Spill				Removed		
	Fish Spill	(only if regulated flow at Lower Granite ≥ 85000 cfs)					2-11-02 PNCA submittal
		13000 cfs			Apr 15	[15000*13/15]	
		15000 cfs			Apr 30 & May		
		10000 cfs			Jun	[15000*20/30]	
	Maximum Fish Spill	15000 cfs					
	Minimum Flow	11500 cfs			Mar - Nov		
	Other	260.5 ksfd		633.0 ft	On MOP Apr - Aug 31.		
		285.0 ksfd		638.0 ft	On full pool Sep 30 - Mar 31.		

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

Project Name (Number)	Constraint Type	Requirements				Source
Lower Monumental (504)	Bypass Date			A bypass date of 2010 was assumed.		
	Other Spill	750 cfs		All periods		
	Fish Spill	(only if regulated flow at Lower Granite ≥ 85000 cfs) 23400 cfs 27000 cfs 18000 cfs		 Apr 15 Apr 30 & May Jun	 [27000*13/15] [27000*20/30]	2-11-02 PNCA submittal
	Maximum Fish Spill	27000 cfs				
	Minimum Flow	11500 cfs		Mar-Nov		
	Other	180.5 ksfd 190.1 ksfd	537.0 ft 540.0 ft	On MOP Apr - Aug 31. On full pool Sep 30 - Mar 31.		
Cushman (2206)	Other Spill	100 cfs		All periods		
LaGrande (2188)	Other Spill	30 cfs		All periods		
White River (2160)	Other Spill	130 cfs		All periods		
Round Butte (390)	Other Spill	200 cfs		All periods		
	Minimum Content	124.6 ksfd 130.6 ksfd 136.3 ksfd	1938.0 ft 1941.0 ft 1944.0 ft	Nov - Apr 30 May Jun - Oct		3-6-01 PNCA submittal
Timothy (117)	Minimum Content	24.5 ksfd 31.1 ksfd 27.8 ksfd	3180.0 ft 3190.0 ft 3185.0 ft	Oct - May Jun - Aug 31 Sep	 [(24.5*15+31.1*15)/30]	3-6-01 PNCA submittal
Long Lake (1305)	Minimum Content	50.1 ksfd 19.7 ksfd	1535.0 ft 1522.0 ft	Apr - Nov Dec - Mar		2-5-02 PNCA submittal
Priest Lake (1470)	Maximum Content Max/Min Content	11.5 ksfd 35.5 ksfd	1.0 ft 3.0 ft	Oct Maintain at or near after runoff through Sep.		2-5-02 PNCA submittal
Ross (2070)	Minimum Content/			Dependent on Skagit Fisheries		2-5-02 PNCA submittal
Gorge (2065)	Minimum Flow			Settlement; monthly data, varies by water year.		2-5-02 PNCA submittal

Appendix A2
(Metric Units)
Project Operating Procedures for the 2006- 07
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Definition of split months:

Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Canadian Projects					
Mica (1890)	Minimum Flow	84.95 m^3/s			In place in AOP79, AOP80, AOP84
Arrow (1831)	Minimum Flow	141.58 m^3/s			In place in AOP79, AOP80, AOP84
	Draft Limit		0.30 m/day		
Duncan (1681)	Minimum Flow	2.83 m^3/s			In place in AOP79, AOP80, AOP84
	Maximum Flow	283.17 m^3/s			In place in AOP79, AOP80, AOP84
	Draft Limit		0.30 m/day		
	Other			Operate to meet IJC orders for Corra Linn	CRTOC agreement on procedures to implement 1938 IJC order
Base System					
Hungry Horse (1530)	Minimum Flow	11.33 m^3/s		Minimum project discharge	In place in AOP79, AOP80, AOP84
	Maximum Flow			None	
	Minimum Content			None	
	Other			No VECC limit	VECC limit not in place in AOP79
Kerr (1510)	Minimum Flow	42.48 m^3/s		All periods	In place in AOP80, AOP84
	Maximum Flow			None	
	Minimum Content	1503.9 hm^3 1043.0 hm^3	881.79 m 880.87 m	Jun - Sep May	MPC 2-1-92, PNCA submittal similar operation, Jun-Aug 15, in AOP80
		0.0 hm^3	878.74 m	Empty Apr 15	FERC, AOP80
	Maximum Content	143.4 hm^3	879.04 m	March (Included to help meet the Apr 15 FERC requirement.)	In place in AOP80, and AOP84
	Other	0.0 hm^3	878.74 m	Conditions permitted, should be on or about, empty Mar and Apr 15.	FERC, AOP80
Thompson Falls (1490)				None Noted	
Noxon Rapids (1480)	Minimum Content For Step I:	284.5 hm^3 274.8 hm^3 192.5 hm^3 64.8 hm^3 0.0 hm^3	710.49 m 710.18 m 707.44 m 702.56 m 699.52 m	May - Aug 31, Sep - Jan, Feb, Mar, Empty Apr 15, Apr 30, and for end of CP.	In place in AOP84, similar operation in AOP80
	Minimum & Maximum Content For Steps II & III:	284.5 hm^3	710.49 m	All periods	In place in AOP79, AOP84

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Definition of split months:

Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Cabinet Gorge (1475)				None Noted	
Albeni Falls (1465)	Minimum Flow	113.27 m^3/s		All periods	In place in AOP80, AOP84
	Minimum Content	(Dec may fill on restriction, note below)			
		1424.9 hm^3	628.65 m	Jun - Aug 31	In place in AOP80,
		1139.4 hm^3	627.89 m	Sep	AOP84
		465.8 hm^3	626.06 m	Oct	
		140.9 hm^3	625.14 m	Nov-Apr 15	
		465.8 hm^3	626.06 m	Apr 30 (empty at end of CP)	
		682.6 hm^3	626.67 m	May	
	For Steps I & II:	Optimum to run CP & LT to Jun-Oct SMINs.			
	For Step III:	Keep full at beginning of CP. Often (not always) optimum to run higher than SMIN in CP & LT (except when occasionally drafting below SMIN to meet load).			
		140.9 hm^3	625.14 m	Nov - Mar	
		1121.5 hm^3	627.83 m	May	
		1424.9 hm^3	628.65 m	Sep	
		1139.4 hm^3	627.89 m	Oct	
	Kokanee Spawning	Draft no more than 0.30 m below Nov 20 elevation through Dec 31. If project fills, draft no more than 0.15 m. Dec 31 - Mar 31 operate between SMIN and URC within above noted draft limits.			In place before AOP80 and supported by minimum contents noted above.
	Other Spill	1.42 m^3/s		All periods	
Box Canyon (1460)				None Noted	
Grand Coulee (1280)	Minimum Flow	849.50 m^3/s		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	0.00 m^3/s	368.20 m	Empty at end of CP	
	Step I only:	2064.7 hm^3	377.95 m	May and June	Retain as a power
	Steps II & III only:	2098.9 hm^3	377.95 m	May and June	operation (for pumping)
	Maximum Content				
	Step I only:		0.61 m	Operating room Sep - Nov	In place in AOP89.
			0.91 m	Operating room Dec - Feb	Retain as a power operation
	Steps II & III only:	6256.2 hm^3	392.58 m	Aug-Nov	
		6161.3 hm^3	392.28 m	Dec-Feb	
	Draft Limit		0.40 m/day	(bank sloughage)	
			0.46 m/day	(Constraint submitted as 0.46 m/day interpreted as 0.40 m/day mo. ave.)	
Chief Joseph (1270)	Other Spill	14.16 m^3/s		All periods	
Wells (1220)	Other Spill	33.98 m^3/s		All periods	With fish ladder
	Fish Spill			None	
Rocky Reach (1200)	Fish Spill/Bypass			None	
	Other Spill	5.66 m^3/s		Aug 31 - Apr 15 (leakage)	
Rock Island (1170)	Fish Spill/Bypass			None	
Wanapum (1165)	Fish Spill/Bypass			None	
	Other Spill	62.30 m^3/s		All periods	With fish ladder

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Definition of split months:

Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Priest Rapids (1160)	Minimum Flow			Limit removed	
	Fish Spill/Bypass			None	
	Other Spill	62.30 m^3/s		All periods	With fish ladder
Brownlee (767)	Minimum Flow	141.58 m^3/s		Variable flow	In place in AOP79, AOP80, AOP84
	Power Operation			Agree to use "old" power operation (first codes) provided by IPC and used in AOP since AOP97 for CP.	2-1-91 PNCA submittal
				LT run to PDP using rule curves from CP with BECC created from regulation spreadsheet to meet flow requirements at Lime Pt., and Brownlee and mimic the "old" historic first code operation on a 60 year average and median comparison. Consistent w/ TSR.	7-00 J. Hyde
Oxbow (765)	Other Spill	2.83 m^3/s		All periods	
Ice Harbor (502)	Fish Spill/Bypass			None	
	Other Spill	20.95 m^3/s		All periods	
	Incremental Spill			None	
	Minimum Flow			None	
	Other	501.1 hm^3	134.11 m	Run at all periods	
McNary (488)	Other Spill	98.40 m^3/s		All periods	
	Incremental Spill			None	
John Day (440)	Fish Spill/Bypass			None	
	Other Spill	22.65 m^3/s		All periods	
	Incremental Spill			None	
	Minimum Flow	1415.84 m^3/s 353.96 m^3/s		Mar - Nov Dec - Feb	
	Other Step I	659.8 hm^3 593.3 hm^3 376.0 hm^3 281.1 hm^3	81.69 m 81.38 m 80.35 m 79.86 m	June - Aug 15 Aug 31 - Sep Oct - Mar Apr - May	In place AOP80
	Steps II & III	464.9 hm^3	80.77 m	Use JDA as run-of-river plant.	
The Dalles (365)	Fish Spill/Bypass			None	
	Other Spill	36.81 m^3/s		All periods	
	Incremental Spill			None	
	Minimum Flow	1415.84 m^3/s 353.96 m^3/s		Mar - Nov Dec - Feb	
Bonneville (320)	Fish Spill/Bypass			None	
	Other Spill	227.67 m^3/s		All periods	
	Incremental Spill			None	

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Definition of split months:

Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements			Source
Kootenay Lake (Corra Linn (1665))	Minimum Flow	141.58 m^3/s		All periods	BCHydro agreements 1969
	Other			Operate to IJC orders.	CRTOC agreement on procedures to implement 1938 IJC order
Chelan (1210)	Minimum Flow	1.42 m^3/s		All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	754.8 hm^3	334.67 m	Jul - Sep (except as needed to empty at end of critical period).	In place in AOP79, AOP80, AOP84
Couer d'Alene L (1341)	Minimum Flow	1.42 m^3/s		All periods	In place in AOP79
	Minimum Content	275.2 hm^3	648.61 m	May - Aug	
Post Falls (1340)	Minimum Flow	1.42 m^3/s		All periods	In place in AOP79, AOP80, AOP84
Other Major Step I Projects					
Libby (1760)	Minimum Flow	113.27 m^3/s		All periods	
	Other Spill	5.66 m^3/s		All periods	
	Minimum Content	By contract year: Aug-Jul i.e., 1929 = Aug 1928 - Jul 1929			
		1900.8 hm^3	720.24 m	1929 Dec	2-1-93 PNCA submittal, in place in AOP99
		1655.1 hm^3	717.80 m	1929 Jan	
		1476.8 hm^3	715.98 m	1929 Feb	
		5254.6 hm^3	744.63 m	1929 Jul	
		1595.2 hm^3	717.19 m	1930 Dec	
		1059.9 hm^3	711.40 m	1930 Jan	
		952.5 hm^3	710.18 m	1930 Feb	
		852.6 hm^3	708.96 m	1930 Mar	
		727.6 hm^3	707.44 m	1930 Apr 15	
		1086.8 hm^3	711.71 m	1930 Apr 30	
		1221.1 hm^3	713.23 m	1930 May	
		3289.7 hm^3	732.13 m	1930 Jun	
		4335.1 hm^3	739.14 m	1930 Jul	
		777.5 hm^3	708.05 m	1931 Dec	
		470.2 hm^3	704.09 m	1931 Jan	
		252.2 hm^3	701.04 m	1931 Feb-Apr 30	
		470.2 hm^3	704.09 m	1931 May	
		1655.1 hm^3	717.80 m	1931 Jun	
		2123.6 hm^3	722.38 m	1931 Jul	
		426.7 hm^3	703.48 m	1932 Dec	
		252.2 hm^3	701.04 m	1932 Jan	
		0.0 hm^3	697.08 m	Empty at end of CP***	
		1900.8 hm^3	720.24 m	All Dec	
		July 1930 - No more than 912.8 hm^3 lower than July 1929 July 1931 - No more than 2097.0 hm^3 lower than July 1930 March - Implement PNCA 6(c)2(c).			2-1-94 PNCA submittal, in place in AOP00 and
	Max Summer Draft		1.52 m		
	Other			Operate to meet IJC orders for Corra Linn	CRTOC agreement on procedures to implement 1938 IJC order

Appendix A2
(Metric Units)
Project Operating Procedures for the 2006- 07
Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:

Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements				Source
Dworshak (535)	Minimum Flow	36.81 m^3/s		All periods		2-11-02 PNCA submittal
	Maximum Flow	396.44 m^3/s		All periods (model includes maximum 396.44 m^3/s for all periods, but URC may overrides.)		2-11-02 PNCA submittal
		707.92 m^3/s		Up to 707.92 m^3/s for flood control all periods.		
	Minimum Content	968.4 hm^3	463.30 m	SMIN Apr - Aug 31		
	Start 3 yr CP at:	968.4 hm^3	463.30 m	15-Aug		
	End 3 yr CP at:	534.3 hm^3	454.21 m	Feb		
	Other	Run on minimum flow or flood control observing maximum & minimum flow requirements Sep-Jun and meets LWG Target flows Jul- Aug31 (based on sliding scale).				2-11-02 PNCA submittal
	LWG Target Flow	1415.84 m^3/s to	1557.43 m^3/s	Jul - Aug 31		2-11-02 PNCA submittal
	Other Spill	2.83 m^3/s		All periods		
Lower Granite (520)	Bypass Date			None		
	Other Spill	18.97 m^3/s		All periods		
	Incremental Spill			Removed		
	Fish Spill	(Only if regulated flow > 2406.93 m^3/s)				2-11-02 PNCA submittal
		466.29 m^3/s		Apr 15	[538.02*13/15]	
		538.02 m^3/s		Apr 30 & May		
		358.69 m^3/s		Jun	[538.02*20/30]	
	Maximum Fish Spill	538.02 m^3/s				
	Minimum Flow	325.64 m^3/s		Mar-Nov		
	Other	550.2 hm^3	223.42 m	On MOP Apr - Oct 31.		
		601.4 hm^3	224.94 m	On full pool Nov 30 - Mar 31.		
Little Goose (518)	Bypass Date			None		
	Other Spill	17.84 m^3/s		All periods		
	Incremental Spill			Removed		
	Fish Spill	(Only if regulated flow at Lower Granite $\geq$ 2406.93 m^3/s)				2-11-02 PNCA submittal
		368.12 m^3/s		Apr 15	[424.75*13/15]	
		424.75 m^3/s		Apr 30 & May		
		283.17 m^3/s		Jun	[424.75*20/30]	
	Maximum Fish Spill	424.75 m^3/s				
	Minimum Flow	325.64 m^3/s		Mar - Nov		
	Other	637.3 hm^3	192.94 m	On MOP Apr - Aug 31.		
		697.3 hm^3	194.46 m	On full pool Sep 30 - Mar 31.		

Appendix A2
(Metric Units)
Project Operating Procedures for the 2006- 07
Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months:

Apr (April 1-30); Apr 15 (April 1-April 15); Apr30 (April 15-April 30); Aug (August 1-31); Aug 15 (August 1-15); Aug 31 (August 16-31).

Project Name (Number)	Constraint Type	Requirements				Source
Lower Monumental (504)	Bypass Date			A bypass date of 2010 was assumed.		
	Other Spill	21.24 m^3/s		All periods		
	Fish Spill	(Only if regulated flow at Lower Granite ≥ 2406.93 m^3/s)				2-11-02 PNCA submittal
		662.61 m^3/s		Apr 15	[764.55*13/15]	
		764.55 m^3/s		Apr 30 & May		
		509.70 m^3/s		Jun	[764.55*20/30]	
	Maximum Fish Spill	764.55 m^3/s				
	Minimum Flow	325.64 m^3/s		Mar-Nov		
	Other	441.6 hm^3	163.68 m	On MOP Apr - Aug 31.		
		465.1 hm^3	164.59 m	On full pool Sep 30 - Mar 31.		
Cushman (2206)	Other Spill	2.83 m^3/s		All periods		
LaGrande (2188)	Other Spill	0.85 m^3/s		All periods		
White River (2160)	Other Spill	3.68 m^3/s		All periods		
Round Butte (390)	Other Spill	5.66 m^3/s		All periods		
	Minimum Content	304.85 hm^3	590.70 m	Nov - Apr 30		3-6-01 PNCA submittal
		319.53 hm^3	591.62 m	May		
		333.47 hm^3	592.53 m	Jun - Oct		
Timothy (117)	Minimum Content	59.94 hm^3	969.26 m	Oct - May		3-6-01 PNCA submittal
		76.09 hm^3	972.31 m	Jun - Aug 31		
		68.02 hm^3	970.79 m	Sep	[(10.01*15+12.71*15)/30]	
Long Lake (1305)	Minimum Content	122.57 hm^3	467.87 m	Apr - Nov		2-5-02 PNCA submittal
		48.20 hm^3	463.91 m	Dec - Mar		
Priest Lake (1470)	Maximum Content	28.14 hm^3	0.30 m	Oct		2-5-02 PNCA submittal
	Max/Min Content	86.85 hm^3	0.91 m	Maintain at or near after runoff through Sep.		
Ross (2070)	Minimum Content/			Dependent on Skagit Fisheries		2-5-02 PNCA submittal
Gorge (2065)	Minimum Flow			Settlement, monthly data, varies by water year.		2-5-02 PNCA submittal

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2006-07

TABLE OF CONTENTS

DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB) FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2006-07

January 2004

1. Introduction

The treaty between Canada and the United States of America (USA) 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 2006-07 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 Entity Agreements, signed 28 July and 12 August 1988, on "Principles for the Preparation of the AOP and Determination of Downstream Power Benefit (DDPB) Studies" and "Changes to Procedures for the Preparation of the AOP and DDPB Studies" (1988 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 (29 August 1996 Entity Agreement); and

- The "Columbia River Treaty Entity Agreement on the Principles and Procedures for Preparing and Implementing Hydroelectric Operating Plans For Operation of Canadian Treaty Storage" (POP), dated 16 December 2003.

The POP is based on criteria contained in Annex A and Annex B of the Columbia River Treaty,[1] the Protocol,[2] and the Columbia River Treaty Flood Control Operating Plan (FCOP).[3] For this DDPB, the Entities have agreed to a Streamline Method that includes:

- Changes to procedures in Section 3.2.B(5) of the POP for determining the thermal installations that are described in Section 6(b) of this document; and

- Changes to procedures for performing the Steps II and III 30-year System Regulation Studies that are described in Section 6(d) of this document.

The Canadian Entitlement Benefits were computed from the following studies:[4]

Step I -- Operation of the total USA Columbia Basin hydro and thermal system, with 19.12 cubic kilometers (km³) (15.5 million acre-feet (Maf)) of Canadian Treaty Storage operated for flood control and optimum power generation in both countries including coordination with other generation in Canada and the USA.

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

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

As part of the DDPB, separate determinations may be 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 USA (Joint Optimum). However, as indicated in Section 3 below, the calculations were not needed for the 2006-07 operating year.

2. Results of Canadian Entitlement Computations

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

Dependable Capacity	= 1244.3 megawatts (MW)
Average Annual Usable Energy	= 488.5 average annual MW

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

3. Computation of Maximum Allowable Reduction in Downstream Power Benefits

Treaty Annex A, paragraph 7, states that:

"Any reduction in the downstream power benefits in the United States of America resulting from that change in operation of the Canadian storage shall not exceed in any one year the reduction in downstream power benefits in the United States of America which would result from reducing by 500,000 acre-feet the Canadian storage operated to achieve optimum power generation in the United States of America and shall not exceed at any time during the period of the Treaty the reduction in downstream power benefits in the United States of America which would result from similarly reducing the Canadian storage by 3,000,000 acre-feet."

Step II studies based on the assumption of optimum power generation in Canada and the USA resulted in a 1.5 average megawatt (aMW) increase in the Energy Entitlement and no change to the Capacity Entitlement (See Table 5, columns A and

B), compared to Step II and III studies based on optimum power generation only in the USA. Since there was no reduction in the downstream power benefits in the 2006-07 DDPB, the computation of the maximum allowable reduction in downstream power benefits, as defined in Section 3.3 A(3) of the POP, was not performed.

4. Delivery of the Canadian Entitlement

See Section 6 of the 2006-07 AOP.

5. Summary of Information Used For Canadian Entitlement Computations

The following tables and chart summarize the study results.

Table 1A and Table 1B — Determination of Firm Hydro Loads for Step I Studies:

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

Table 2 — Determination of Thermal Displacement Market:

This table shows the computation of the Thermal Displacement Market (TDM) for the downstream power benefit determination of average annual usable energy. The TDM was limited to the Thermal Installations with reductions for minimum thermal generation and system sales, which are the thermal resources used to meet load outside the Pacific Northwest Area (PNWA).

Table 3 — Determination of Loads for 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 the PNWA load. The PNWA firm loads were based on the Bonneville Power Administration (BPA) 2000 White Book (WB) load forecast. The Grand Coulee pumping load is 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 the POP.

Table 4 — Summary of Power Regulations from 2006-07 Assured Operating Plan:

This table summarizes the results of the Step I, II, and III power regulation studies for each project and the total system. The determination of the Step I, II, and III loads and thermal installations is shown in Tables 1 and 3. The hydro maintenance is summed with the reserves in the Step I system load as an adjustment to resources.

Table 5 Computation of Canadian Entitlement For 2006-07 Assured Operating Plan:
A. Joint Optimum Generation in Canada and the USA
B. Optimum Generation in the USA Only

The essential elements used in the computation of the Canadian Entitlement arising from the downstream power benefits under the Joint Optimum and USA Optimum are shown under Columns A and B respectively. The elements for the computation of maximum allowable reduction in downstream power benefits are not shown in this table because that calculation is not necessary as explained in section 3.

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 in aMW from the Step II and III studies, which graphically illustrates the change in average annual usable hydro energy. Usable hydro energy consists of firm energy plus usable nonfirm energy. Firm energy is the firm hydro loads shown in Table 3, and nonfirm energy is the monthly hydro energy capability in excess of the firm hydro loads. The usable nonfirm energy is computed in accordance with Annex B, paragraphs 3(b) and 3(c), as the portion of nonfirm energy that can be used to displace Thermal Installations designated to meet PNWA firm loads. The Entities have agreed that remaining usable energy is computed on the basis of 40 percent of the nonfirm energy remaining after thermal displacement.

6. Summary of Changes from Previous Year and Notable Assumptions

Data from recent DDPB's are summarized in Table 6. An explanation of the more important changes and notable assumptions that impact computation of the entitlement compared to the 2005-06 DDPB studies follows.

(a) Loads

Loads for the 2006-07 AOP were based on BPA's December 2000 WB medium-case load forecast. This new forecast was the first major update to BPA's regional load forecast procedures since 1996. The previous forecast had a 0.5% average annual load growth rate and the new forecast has a 1.6% average annual load growth rate from the 2005-06 to the 2006-07 operating year. The change is mostly due to more detailed estimates for investor owned utilities and a significant reduction in direct service industry (mainly aluminum) loads. The net effect of the new load forecast is that the 2006-07 AOP PNWA firm load is 1,520 aMW (6.8%) greater than that in the 2005-06 AOP. Other regional load forecasts are not available for 2006-07 operating year, however the 2000 WB load forecast for the 2005-06 operating year compares well and is slightly lower than the Northwest Power Planning Council load forecast. Other load changes include:

- It was assumed that one-half of the Canadian Entitlement was exported to B.C., and the remaining one-half was disposed in the USA. The estimated disposition of the Entitlement in the Step I system was based on the 2005-06 DDPB. The estimated and the computed Canadian Entitlement are shown below:

  During 1 August 2006 – 31July 2007

Canadian Entitlement	Energy (aMW)		Capacity (MW)	
Return	Estimated	Computed	Estimated	Computed
Export to BC (1/2)	267.6	244.3	609.0	622.2
Retained in PNW (1/2)	267.6	244.3	609.0	622.2
Total	535.1	488.5	1218.0	1244.3

  Iterative studies to update the Canadian Entitlement in the load estimate were not performed because they would change the Step I System load by about 0.1% which would not significantly affect the results of the studies.

- Compared to the 2005-06 AOP, exports (mostly to the Southwest) decreased by 681 aMW, mainly due to expiration of several firm contracts. Imports increased by 161 aMW.

- The Step I System load is reduced by Hydro Independent generation, Non-Step I Coordinated Hydro, and non-Thermal and miscellaneous resources. The most notable change was a 412 aMW increase in Miscellaneous Non-Thermal resources, mainly numerous Wind Generators.

(b) Thermal Installations

Because of increasing difficulty in forecasting Thermal Installations, the Entities changed procedures for forecasting Thermal Installations in this AOP/DDPB by assuming one generic Thermal Installation, except for the Columbia Generating Station (CGS, formerly called Washington Public Power Supply System #2 nuclear power plant). The quantity of generic Thermal Installation is defined as that needed, together with CGS, to meet the Step I System Load minus Step I Hydro capability. The annual shape of generic Thermal Installation was the same as in the 2005-06 AOP. The CGS was modeled separately because of its large size and a two-year maintenance cycle with outages only in the second half of May and June during odd years. The total Thermal Installations increased by 263 aMW compared to the 2005-06 AOP/DDPB.

The TDM increased by 1,141 aMW due to the combination of increased thermal installations explained above (263 aMW), a decrease in System Sales (-879 aMW), and a small increase (1 aMW) in Minimum Thermal Generation.

(c) Hydro Project Operating Procedures

The nonpower requirements for Base system projects were agreed to in the 29 August 1996 Entity Agreement. These requirements are essentially the nonpower requirements included in the 1979-80 and prior AOP/DDPB studies.

The critical rule curves, refill curves, and Mica operating criteria were updated in accordance with procedures defined in the POP, except that the VRC Lower Limits were not updated from the 2005-06 AOP. Other changes and notable assumptions include:

Canadian Projects

- Flood control data reflects an agreed allocation of flood control space in Mica and Arrow of 5.03 and 4.44 km^3 (4.08 and 3.6 Maf), respectively. In the 2005-06 and prior AOP's the flood control allocation was 2.57 and 6.29 km^3 (2.08 and 5.1 Maf).
- The APOC as described in the AOP section 4(d), were implemented in the Step II study through use of maximum storage limits.

Base System Projects

- The Brownlee storage operation outside the critical period was simulated by using CRC's and ORC's designed to closely follow the fixed operation from Idaho Power Company (IPC) used in the 2003-04 and previous AOP's. The CRC's were based on the IPC's forecast of critical period operation during 1929-32 for the Step I studies, 1944-45 for Step II, and 1936-37 for Step III. ORC's were revised compared to the 2005-06 AOP to more closely follow the historic forecast of IPC operation.
- The Grand Coulee flood control rule curve in the Step II and III studies was changed slightly from the 2005-06 AOP/DDPB due to the implementation of the 5.03/4.44 km^3 (4.08/3.6 Maf) Mica/Arrow flood control allocation. The Canadian Entity is concerned that this change may not be appropriate for the Step III study, which does not include Mica and Arrow. However, to avoid delay in completing this DDPB, the Canadian Entity accepts the change in Grand Coulee flood control rule curve for this operating year on a "without prejudice" basis.

(d) Step II and III Critical Period and 30-year System Regulation Studies

Steps II and III critical period regulation studies for the 2006-07 operating year were performed to establish critical period capability as described in Section 2.2.A of the POP. The Steps II and III critical streamflow periods were unchanged from the 2005-06 studies. The Step II critical period was the 20 calendar-months from 1 September 1943 through April 30, 1945, and the Step III critical streamflow period was the 5.5 calendar-months from 1 November 1936 through 15 April 1937.

For the 30-year System Regulation Studies, the Entities agreed to a Streamline Method that uses the 2007-08 Steps II (-42 and -12) and III (-13) 30-year System Regulation Studies, together with a month-to-month generation reshaping procedure, to estimate Steps II and III 30-year average annual usable hydro energy for this DDPB. The procedure reshaped the 2007-08 Steps II and III 30-year hydro system generation to meet the 2006-07 firm hydro loads. The

Entities have verified that the Streamline Method for preparing 30-year Step II/III System Regulation Studies significantly reduces study effort and produces accurate results.

(e) Downstream Power Benefits Computation

The Capacity Entitlement increased from 1218.0 MW in the 2005-06 DDPB to 1244.3 MW in the 2006-07 DDPB for a gain of 26.3 MW. The average critical period generation in the Step II study increased by 1.5 MW and the Step III average generation decreased by 19 MW. The Step III average critical period generation decreased due to the lower hydro load in November as a result of the change in annual energy load shape. The Step I average critical period load factor decreased by 0.8%, causing about one-half of the increase in the Capacity Entitlement.

The Energy Entitlement changed from 535.1 aMW in the 2005-06 DDPB to 488.5 aMW in the 2006-07 DDPB for a decrease of 46.6 aMW. The change was mostly due to a 1,141 aMW increase in the TDM, which tends to decrease the energy entitlement (roughly 2 to 3 aMW decrease for each 100 MW increase in TDM). The decrease in Energy Entitlement is also significantly affected by the change in CGS maintenance, which caused about 10 aMW of the decrease.

End Notes

1 "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.

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

3 "Columbia River Treaty Flood Control Operating Plan," dated October 1999, subsequently superceded by the Plan of May 2003.

4 The Treaty defines the Canadian Treaty Storage in English units. The metric conversion is a rounded approximation.

TABLE 1A

2006-07 ASSURED OPERATING PLAN
DETERMINATION OF FIRM ENERGY HYDRO LOADS FOR STEP I STUDIES (aMW) 1/

(Energy in Average MW)

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July	Annual Average	CP Ave 2/ (42.5 Mon)
1. **Pacific Northwest Area (PNWA) Firm Load**																
a) White Book (WB) Regional Firm Load 3/	22638	22636	21705	22537	24755	26862	27509	26522	24508	23535	23513	22540	22988	23361	24110.6	24215.3
b) Remove Utah Load	-480	-480	-350	-303	-314	-285	-350	-350	-332	-317	-317	-355	-505	-570	-376.2	-370.3
c) Total PNWA Firm Load for Step 1 4/	**22158**	**22156**	**21355**	**22234**	**24441**	**26577**	**27159**	**26172**	**24176**	**23218**	**23195**	**22186**	**22483**	**22791**	**23734.4**	**23845.0**
d) Annual Load Shape in Percent	93.36	93.35	89.97	93.68	102.98	111.98	114.43	110.27	101.86	97.82	97.73	93.48	94.73	96.02	100.0	100.5
2. **Flows-Out of firm power from PNWA**																
a) WB Exports	1503	1503	1424	1149	1127	1131	974	959	942	978	978	985	1187	1215	1132.0	1136.0
b) Remove WB Canadian Entitlement export	-532	-532	-532	-532	-532	-532	-532	-532	-532	-532	-532	-532	-532	-532	-532.0	-532.0
c) Add estimated Canadian Entitlement (south+north	268	268	268	268	268	268	268	268	268	268	268	268	268	268	267.6	267.6
d) Add Seas Exch Export (Surplus firm energy export	766	774	1171	0	0	0	0	0	0	0	634	2210	1870	2026	701.2	630.6
e) Subtotal for Table 2	2004	2012	2331	885	862	867	709	694	677	714	1348	2930	2793	2977	1568.8	1502.1
f) Remove Plant Sales	-135	-135	-135	-135	-135	-135	-135	-135	-135	-135	-135	-88	-135	-135	-131.0	-131.6
g) Total	**1869**	**1877**	**2196**	**750**	**727**	**732**	**574**	**559**	**542**	**579**	**1213**	**2842**	**2658**	**2842**	**1437.8**	**1370.5**
3. **Flows-In of firm power except from coordinated thermal installations**																
a) WB Imports (Including thermal installations)	-1416	-1416	-1030	-1119	-1591	-1651	-1650	-1656	-1442	-1259	-1218	-1208	-1408	-1527	-1410.4	-1415.8
b) Remove Thermal Install (- PP&I - Utah - PSW - SW	1327	1327	943	1041	1421	1466	1472	1469	1324	1171	1147	1139	1326	1451	1294.5	1295.9
c) Net Non-Thermal Imports for Table 2	-89	-89	-86	-78	-170	-185	-178	-187	-118	-87	-71	-69	-82	-75	-115.9	-120.0
d) Add Seas Exch Import to support expected sales 7	0	0	0	-606	-1139	-1227	-1844	-2226	-875	-1226	0	0	0	0	-701.3	-758.4
e) Total	**-89**	**-89**	**-86**	**-684**	**-1309**	**-1412**	**-2022**	**-2413**	**-993**	**-1313**	**-71**	**-69**	**-82**	**-75**	**-817.2**	**-878.4**
4. **Non-Step I Hydro and Non-thermal Resources Located within the PNWA**																
a) Hydro Independents (1929 water)	-1282	-1255	-1175	-1201	-1231	-1159	-1102	-924	-1045	-1281	-1327	-1772	-1727	-1426	-1279.8	-1143.9
b) Non-Step I Coordinated Hydro (1929 water)	-512	-470	-554	-943	-949	-1007	-1007	-592	-672	-716	-813	-698	-1306	-790	-815.4	-841.5
c) Misc Non-thermal Resources (from input_data)	-536	-535	-427	-370	-455	-531	-506	-458	-535	-630	-629	-711	-704	-618	-540.4	-528.8
d) Total (1929)	**-2329**	**-2260**	**-2156**	**-2514**	**-2635**	**-2697**	**-2615**	**-1974**	**-2252**	**-2627**	**-2769**	**-3181**	**-3737**	**-2833**	**-2635.6**	**-2514.1**
5. **Total Step I System Loads (1929 water) 8/**	**21609**	**21684**	**21309**	**19786**	**21224**	**23200**	**23097**	**22345**	**21474**	**19856**	**21568**	**21778**	**21321**	**22724**	**21719.3**	**21823.0**
6. **Step I Coordinated Thermal Installations**																
a) Columbia Generating Station (WNP2)	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	500	0	1000	875.3	894.4
b) Thermal Installations to meet firm load 9/	10015	10014	10023	9956	10020	10015	10029	10036	9836	8990	8567	8505	8564	9841	9634.8	9692.7
c) Total	**11015**	**11014**	**11023**	**10956**	**11020**	**11015**	**11029**	**11036**	**10836**	**9990**	**9567**	**9005**	**8564**	**10841**	**10510.1**	**10587.1**
7. **Total Step I Hydro Load (1929 water) 10/**	**10594**	**10670**	**10286**	**8830**	**10204**	**12185**	**12068**	**11309**	**10638**	**9866**	**12001**	**12773**	**12758**	**11883**	**11209.2**	**11235.9**
a) Hydro Maintenance included as load	31	25	9	9	4	0	0	0	5	7	8	20	15	50	12.4	11.3
b) Coordinated Hydro Model Load (1929) 11/	**11137**	**11165**	**10849**	**9782**	**11157**	**13192**	**13075**	**11901**	**11315**	**10589**	**12822**	**13491**	**14079**	**12723**	**12037.0**	**12088.7**
c) Coordinated Hydro Model Load shape (1929) 11/	92.52%	92.76%	90.13%	81.27%	92.69%	109.60%	108.62%	98.87%	94.00%	87.97%	106.53%	112.08%	116.96%	105.70%	1.0	0.3

Notes:

1/ Step I Loads and Resources for the U.S. Optimum Study (07-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements. The annual average (aMW) is not a leap year.

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

3/ Total regional firm load plus pumping and Utah loads. Source is the 2000 BPA White Book.

4/ In accordance with the Protocal 10, the Total PNWA Firm Load includes 111 aMW of Grand Coulee pumping (148 aMW of total pumping), but excludes the Utah load.

5/ Includes uniform export of 1/2 Canadian Entitlement, 1/2 remained in region.

6/ Seasonal shaping used in the 2006-07 AOP.

7/ Seasonal exchange import to balance the shaping in item 6.

8/ Line 1(c)+ line 2(g) + line 3(e) + line 4(d).

9/ Thermal installation are assumed to be one generic thermal installation (w/o CGS) added to meet the Step 1 System load minus hydro capability with the same annual shape as the 2006 AOP thermal without CGS.

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

11/ The Coordinated Hydro Model Load is the Step I Hydro Load plus Hydro Maintence plus Non-Step I Coordianted Hydro, lines 7 - 4(b) + 7(a).

TABLE 1B
2006-07 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) Firm Load														
a) White Book (WB) Regional Firm Load 2/	29740	29737	28742	31057	33856	36666	37734	36572	33847	32250	32249	30658	29800	30296
b) Remove Utah Load	-572	-572	-460	-371	-378	-278	-441	-415	-413	-366	-366	-371	-652	-657
c) Remove Federal Peak Diversity	-833	-833	-836	-874	-792	-617	-634	-619	-822	-769	-769	-872	-842	-854
d) .....Total PNWA Firm Load for Step 1 3/	**28334**	**28332**	**27446**	**29813**	**32686**	**35771**	**36658**	**35539**	**32612**	**31115**	**31114**	**29415**	**28306**	**28785**
e) Monthly Load Factors in Percent	78.20	78.20	77.81	74.58	74.78	74.30	74.09	73.64	74.13	74.58	74.58	75.42	79.43	79.18
2. Flows-Out of firm power from PNWA														
a) WB Exports	2536	2536	2442	2074	1983	2014	1869	1845	1826	1829	1829	1951	2105	2172
b) Remove WB Canadian Entitlement export	-1176	-1176	-1176	-1176	-1176	-1176	-1176	-1176	-1176	-1176	-1176	-1176	-1176	-1176
c) Add estimated Canadian Entitlement (south+north) 4/	609	609	609	609	609	609	609	609	609	609	609	609	609	609
d) Add Seas Exch Export (Surplus firm energy exports) 5/	980	990	1505	0	0	0	0	0	0	0	850	2930	2355	2559
e) ...Subtotal for Table 2	2948	2959	3380	1507	1416	1447	1302	1278	1259	1262	2112	4314	3893	4163
f) Remove Plant Sales	-180	-180	-180	-180	-180	-180	-180	-180	-180	-180	-180	-180	-180	-180
g) ...Total	**2768**	**2778**	**3199**	**1326**	**1236**	**1267**	**1122**	**1097**	**1079**	**1082**	**1932**	**4134**	**3713**	**3983**
3. Flows-In of firm power except from coordinated thermal installations														
a) WB Imports (Including thermal installations)	-1699	-1699	-1254	-1373	-1684	-1957	-1979	-1995	-1713	-1329	-1329	-1638	-1834	-1709
b) Remove Thermal Install (- PP&I - Utah - PSW - SW Thrm)	1507	1507	1061	1193	1407	1650	1662	1644	1468	1152	1152	1466	1661	1536
c) ....Net Non-Thermal Imports for Table 2	-192	-192	-193	-181	-277	-307	-317	-351	-245	-177	-177	-173	-173	-173
d) Add Seas Exch Import to support expected sales 6/	0	0	0	-813	-1523	-1651	-2489	-3022	-1180	-1644	0	0	0	0
e) ...Total	**-192**	**-192**	**-193**	**-993**	**-1800**	**-1958**	**-2806**	**-3373**	**-1425**	**-1821**	**-177**	**-173**	**-173**	**-173**
4. Non-Step I Hydro and Non-thermal Resources Located within the PNWA														
a) Hydro Independents (1937 water)	-2050	-2028	-1937	-1787	-1633	-1594	-1548	-1664	-1787	-1995	-2003	-2169	-2209	-2116
b) Non-Step I Coordinated Hydro (1937 water)	-2573	-2494	-2595	-2538	-2436	-2365	-2225	-2031	-2028	-2050	-2110	-2087	-2401	-2601
c) Misc Non-thermal resources (from input_data)	-577	-577	-475	-415	-485	-558	-535	-493	-566	-648	-648	-731	-709	-634
e) ...Total (1937)	**-5200**	**-5099**	**-5007**	**-4740**	**-4555**	**-4517**	**-4309**	**-4188**	**-4380**	**-4693**	**-4760**	**-4988**	**-5319**	**-5351**
5. Total Step I System Firm Loads (1937water) 7/	**25709**	**25819**	**25446**	**25406**	**27567**	**30563**	**30665**	**29075**	**27885**	**25682**	**28108**	**28389**	**26528**	**27245**
6. Step I Coordinated Thermal Installations														
a) Columbia Generating Station (WNP2)	1162	1162	1162	1162	1162	1162	1162	1162	1162	1162	1162	1162	0	1162
b) Thermal Installations to meet firm load 8/	10769	10768	10777	10705	10775	10769	10784	10792	10576	9667	9212	9146	9208	10582
c) ...Total	**11931**	**11930**	**11939**	**11867**	**11937**	**11931**	**11946**	**11954**	**11738**	**10829**	**10374**	**10308**	**9208**	**11744**
7. Step I Hydro Load (1937 water) 9/	**13778**	**13889**	**13507**	**13538**	**15630**	**18632**	**18720**	**17121**	**16147**	**14854**	**17735**	**18081**	**17320**	**15501**
a) Hydro Maintenance included as load	4605	4042	3787	3208	2935	2037	1561	2288	2631	2751	2483	2360	2202	3721
b) Coordinated Hydro Model Load (1937 water) 10/	20956	20425	19889	19285	21001	23034	22506	21440	20806	19655	22327	22528	21923	21823

Note:

1/ Step I Loads and Resources for the U.S. Optimum Study (07-11) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements.

2/ Total regional firm load plus pumping and Utah loads. Source is the 2000 BPA White Book.

3/ In accordance with the Protocal 10, the Total PNWA Firm Load includes Grand Coulee pumping, which is part of the total pumping load, but excludes the Utah load and the Federal peak diversity.

4/ Includes uniform export of 1/2 Canadian Entitlement, 1/2 remained in region.

5/ Seasonal shaping for flows-out is the seasonal shaping for energy (Table1A, line 2(d)) divided by the monthly load factor in percent, line 1(e) above.

6/ Seasonal shaping for flows-in are the same as the energy flows-out, Table 1A, line 3(d).

7/ Line 1(d)+ line 2(g) + line 3(e) + line 4(d).

8/ Peak generation for thermal installations is the energy generation from Table 1A, line 6(b) divided by 95% plant factor.

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

10/ The Coordinated Hydro Model Load is the Step I Hydro Load plus Hydro Maintence plus Non-Step I Coordianted Hydro, lines 7 - 4(b) + 7(a).

TABLE 2

2006-07 ASSURED OPERATING PLAN
DETERMINATION OF THERMAL DISPLACEMENT MARKET
(Energy in Average MW)

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	June	July	Annual Average	CP Ave (42.5 Mon)
1. STEP I THERMAL INSTALLATIONS																
a) From Table 1A, line 6(c)	11015	11014	11023	10956	11020	11015	11029	11036	10836	9990	9567	9005	8564	10841	10510.1	10587.1
2. DISPLACEABLE THERMAL RESOURCES																
a) Minimum Generation as a % of Thermal Install	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231.2	231.2
b) Net Displaceable Thermal Resources	**10784**	**10783**	**10791**	**10725**	**10789**	**10784**	**10798**	**10805**	**10605**	**9759**	**9336**	**8774**	**8333**	**10610**	**10278.9**	**10355.9**
3. SYSTEM SALES																
a) Flows-Out (Table 1A, Line 2(e))	2004	2012	2331	885	862	867	709	694	677	714	1348	2930	2793	2977	1568.8	1502.1
b) Exclude Seasonal Exchange Exports	-766	-774	-1171	0	0	0	0	0	0	0	-634	-2210	-1870	-2026	-701.2	-630.6
c) Exclude Plant Sales Exports	-135	-135	-135	-135	-135	-135	-135	-135	-135	-135	-135	-88	-135	-135	-131.0	-131.6
d) Exclude Flow-Through Transfers w/ Seas Exch Imports	-89	-89	-86	-78	-170	-185	-178	-187	-118	-87	-71	-69	-82	-75	-115.9	-120.0
e) Exclude Canadian Entitlement (out of PNWA)	-268	-268	-268	-268	-268	-268	-268	-268	-268	-268	-268	-268	-268	-268	-267.6	-267.6
f) ...Total System Sales	**747**	**747**	**671**	**404**	**290**	**279**	**129**	**105**	**156**	**224**	**240**	**296**	**438**	**473**	**353.1**	**352.4**
g) Uniform Average Annual System Sales	353	353	353	353	353	353	353	353	353	353	353	353	353	353	353.1	353.1
4. THERMAL DISPLACEMENT MARKET	**10431**	**10430**	**10438**	**10372**	**10436**	**10431**	**10444**	**10452**	**10252**	**9406**	**8983**	**8421**	**7979**	**10257**	**9925.8**	**10002.8**

Notes:

Line 2a Minimum generation is 2.2% of the annual average Step 1 thermal; based on 2006 AOP.

Line 3a System Sales Flows-Out include the seasonal exchange exports; line 2(e), Table 1A.

Line 3b Seasonal Exchange Exports are supported by Seasonal Exchange Imports instead of Thermal Installations; line 2(d), Table 1A.

Line 3c Plant sales include Longview Fibre and approximately 22 percent of Boardman; line 2(f), Table 1A.

Line 3d Flow through transfers include Flows-in that support Flows-Out, i.e. SW & Inland imports (non-thermal imports);line 3(c), Table 1A.

Line 3f System Sales are total exports excluding exchanges, plant sales, flow-thru-xfers, and the Canadian Entitlement. The sum of Lines 3(a) through 3(e).

Line 3g Average Annual System Sales shaped uniformly per 1988 Entity Agreement assumption that shaping is supported by hydro system.

Line 4 PNW Area Thermal Displacement Market is the Total Displaceable Thermal Resources used to meet PNW Area firm loads. Lines 2(b) minus 3(g).

TABLE 3
2006-07 ASSURED OPERATING PLAN
DETERMINATION OF LOADS FOR
STEP II AND STEP III STUDIES

LOAD OF THE PACIFIC NORTHWEST AREA						STEP II STUDY		STEP III STUDY		
Period	PNW Area 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
Aug. 1-15	22158	93.36	28334	78.20	11015	18146.1	7130.9	15680.5	4665.2	Aug. 1-15
Aug. 16-31	22156	93.35	28332	78.20	11014	18144.6	7130.4	15679.1	4664.9	Aug. 16-31
September	21355	89.97	27446	77.81	11023	17488.6	6466.1	15112.3	4089.8	September
October	22234	93.68	29813	74.58	10956	18208.5	7252.7	15734.4	4778.5	October
November	24441	102.98	32686	74.78	11020	20015.9	8995.5	17296.2	6275.8	November
December	26577	111.98	35771	74.30	11015	21765.3	10750.0	18807.9	7792.6	December
January	27159	114.43	36658	74.09	11029	22241.9	11213.1	19219.7	8190.9	January
February	26172	110.27	35539	73.64	11036	21433.8	10397.7	18521.5	7485.4	February
March	24176	101.86	32612	74.13	10836	19799.3	8963.3	17109.1	6273.0	March
April 1-15	23218	97.82	31115	74.58	9990	19014.2	9024.2	16430.6	6440.6	April 1-15
April 16-30	23195	97.73	31114	74.58	9567	18995.7	9428.8	16414.7	6847.7	April 16-30
May	22186	93.48	29415	75.42	9005	18169.1	9163.7	15700.4	6694.9	May
June	22483	94.73	28306	79.43	8564	18412.3	9848.5	15910.5	7346.7	June
July	22791	96.02	28785	79.18	10841	18664.6	7823.3	16128.5	5287.3	July
Annual Average 7/ =	23734.4	100.00		75.85	10510.1	19437.3	8927.2	16796.2	6286.1	Annual Avg
SI CP avg(42.5) =	23845.0			75.74	10587.1					
S2 CP avg(20) =	24007.7				10641.1	19661.1	9020.0			**<==Sep-Ap30**
S3 CP avg(5.5) =	25479.5				10896.1			18031.2	7135.1	**<==Nov-Ap15**
						Input 5/=	**9020.0**	Input 6/=	**7135.1**	
August 1-31	22156.8	93.4	28334.2	78.20	11014.7	18145.3	7130.6	15679.8	4665.1	Aug. 1-31
April 1-30	23206.4	97.8	31114.6	74.58	9778.5	19004.9	9226.5	16422.6	6644.2	Apr. 1-30

1/ The PNW Area load does not include the exports, but does include pumping. The computation of the load shape for Step II/III studies used these loads.

2/ The thermal installations include all thermal used to meet the Step I system load. (Table 2, line 1).

3/ The total firm load for the Step II/III studies is computed to have the same shape as the load of the PNW Area.

4/ The hydro load is equal to the total load minus the Step I study thermal installations for each period.

5/ Input is the assumed critical period average generation for the Step II hydro studies and is used to calculate the residual hydro loads.

6/ Input is the assumed critical period average generation for the Step III hydro studies and is used to calculate the residual hydro loads.

7/ The Annual Average is for 2006-07 operating year which is not a leap year. The critical period (CP) averages are for the historic water years.

TABLE 4
(English Units)
SUMMARY OF POWER REGULATIONS
FROM 2006-07 ASSURED OPERATING PLAN

PROJECTS	BASIC DATA		STEP I			STEP II				STEP III			
	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE kaf	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE kaf	JANUARY 1946 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE kaf	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW
HYDRO RESOURCES													
CANADIAN													
Mica			7000			7000							
Arrow			7100			7100							
Duncan			1400			1400							
Subtotal			15500			15500							
BASE SYSTEM													
Hungry Horse	4	428	3072	300	102	3008	176	114	103	3008	328	241	105
Kerr	3	160	1219	180	123	1219	175	112	129	1219	174	153	123
Thompson Falls	6	85	0	85	56	0	85	53	59	0	85	66	57
Noxon Rapids	5	554	231	549	153	0	554	134	202	0	554	182	202
Cabinet Gorge	4	239	0	239	102	0	239	91	119	0	239	116	117
Albeni Falls	3	50	1155	21	23	1155	18	22	21	1155	15	16	20
Box Canyon	4	74	0	71	46	0	70	45	48	0	69	57	47
Grand Coulee	24+3SS	6684	5185	6364	2058	5072	6364	1846	2400	5072	5644	1241	2287
Chief Joseph	27	2535	0	2535	1069	0	2535	974	1305	0	2535	718	1239
Wells	10	840	0	840	421	0	840	389	488	0	840	292	443
Chelan	2	54	677	51	38	676	51	37	44	676	51	51	43
Rocky Reach	11	1267	0	1267	575	0	1267	532	692	0	1267	393	646
Rock Island	18	513	0	513	256	0	513	239	300	0	513	178	279
Wanapum	10	986	0	986	518	0	986	481	602	0	986	346	539
Priest Rapids	10	912	0	912	510	0	912	476	573	0	912	352	510
Brownlee	5	675	975	675	240	974	675	311	324	974	675	274	320
Oxbow	4	220	0	220	99	0	220	127	128	0	220	121	128
Ice Harbor	6	693	0	693	212	0	693	231	302	0	693	168	302
McNary	14	1127	0	1127	622	0	1127	604	768	0	1127	465	717
John Day	16	2484	535	2484	940	0	2484	920	1253	0	2484	697	1215
The Dalles	22+2F	2074	0	2074	747	0	2074	731	992	0	2074	569	970
Bonneville	18+2F	1088	0	1047	566	0	1047	551	682	0	1047	440	642
Kootenay Lake	0	0	673	0	0	673	0	0	0	673	0	0	0
Coeur d'Alene Lake	0	0	223	0	0	223	0	0	0	223	0	0	0
Total Base and Canadian System Hydro 1/		23742	29445	23232	9476	28500	23105	9020	11536	13000	22532	7135	10949
ADDITIONAL STEP I PROJECTS													
Libby	5	600	4980	549	198								
Boundary	6	1055	0	855	368								
Spokane River Plants 2/	24	173	104	168	100								
Hells Canyon	3	450	0	450	192	NOT APPLICABLE TO STEP II & III							
Dworshak	3	450	2015	443	151								
Lower Granite	6	932	0	930	212								
Little Goose	6	932	0	928	209								
Lower Monumental	6	932	0	922	214								
Pelton, Rereg. & RB	7	423	274	419	128								
Total added step 1		5947	7373	5666	1772								
THERMAL INSTALLATION 3/				11946	10587		11946	10641			11946	10896	
RESERVES, HYDRO MAINTENANCE 4/				-4494	-11		-2444	0			-1990	0	
TOTAL RESOURCES				36349	21823		32607	19661			32488	18031	
STEP I, II, & III LOADS 5/				30665	21823		30550	19661			24874	18031	
SURPLUS				5684	0		2056	0			7614	0	
CRITICAL PERIOD	Starts		August 16, 1928			September 1, 1943				November 1, 1936			
	Ends		February 29, 1932			April 30, 1945				April 15, 1937			
	Length (Months)		42.5 Months			20 Months				5.5 Months			
	Study Identification		07-41			07-42				07-13			

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

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

3/ 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 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 2006-07 ASSURED OPERATING PLAN

	BASIC	DATA	STEP I			STEP II				STEP III 4/			
PROJECTS	NUMBER OF UNITS	NOMINAL INSTALLED PEAKING CAPACITY MW	USABLE STORAGE hm^3	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE hm^3	JANUARY 1944 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE hm^3	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW
HYDRO RESOURCES													
CANADIAN													
Mica			8635			8635							
Arrow			8758			8758							
Duncan			1727			1727							
Subtotal			19119			19119							
BASE SYSTEM													
Hungry Horse	4	428	3789	300	102	3710	176	114	103	3710	328	241	105
Kerr	3	160	1504	180	123	1504	175	112	129	1504	174	153	123
Thompson Falls	6	85	0	85	56	0	85	53	59	0	85	66	57
Noxon Rapids	5	554	285	549	153	0	554	134	202	0	554	182	202
Cabinet Gorge	4	239	0	239	102	0	239	91	119	0	239	116	117
Albeni Falls	3	50	1425	21	23	1425	18	22	21	1425	15	16	20
Box Canyon	4	74	0	71	46	0	70	45	48	0	69	57	47
Grand Coulee	24+3SS	6684	6396	6364	2058	6256	6364	1846	2400	6256	5644	1241	2287
Chief Joseph	27	2535	0	2535	1069	0	2535	974	1305	0	2535	718	1239
Wells	10	840	0	840	421	0	840	389	488	0	840	292	443
Chelan	2	54	835	51	38	834	51	37	44	834	51	51	43
Rocky Reach	11	1267	0	1267	575	0	1267	532	692	0	1267	393	646
Rock Island	18	513	0	513	256	0	513	239	300	0	513	178	279
Wanapum	10	986	0	986	518	0	986	481	602	0	986	346	539
Priest Rapids	10	912	0	912	510	0	912	476	573	0	912	352	510
Brownlee	5	675	1203	675	240	1201	675	311	324	1201	675	274	320
Oxbow	4	220	0	220	99	0	220	127	128	0	220	121	128
Ice Harbor	6	693	0	693	212	0	693	231	302	0	693	168	302
McNary	14	1127	0	1127	622	0	1127	604	768	0	1127	465	717
John Day	16	2484	660	2484	940	0	2484	920	1253	0	2484	697	1215
The Dalles	22+2F	2074	0	2074	747	0	2074	731	992	0	2074	569	970
Bonneville	18+2F	1088	0	1047	566	0	1047	551	682	0	1047	440	642
Kootenay Lake	0	0	830	0	0	830	0	0	0	830	0	0	0
Coeur d'Alene Lake	0	0	275	0	0	275	0	0	0	275	0	0	0
Total Base and Canadian System Hydro 1/		23742	36320	23232	9476	35155	23105	9020	11536	16036	22532	7135	10949
ADDITIONAL STEP I PROJECTS													
Libby	5	600	6143	549	198								
Boundary	6	1055	0	855	368								
Spokane River Plants 2/	24	173	128	168	100								
Hells Canyon	3	450	0	450	192				NOT APPLICABLE TO STEP II & III				
Dworshak	3	450	2486	443	151								
Lower Granite	6	932	0	930	212								
Little Goose	6	932	0	928	209								
Lower Monumental	6	932	0	922	214								
Pelton, Rereg., & RB	7	423	338	419	128								
Total added step 1		5947	9095	5666	1772								
THERMAL INSTALLATION 3/				11946	10587		11946	10641			11946	10896	
RESERVES, HYDRO MAINTENANCE 4/				-4494	-11		-2444	0			-1990	0	
TOTAL RESOURCES				36349	21823		32607	19661			32488	18031	
STEP I, II, & III LOADS 5/				30665	21823		30550	19661			24874	18031	
SURPLUS				5684	0		2056	0			7614	0	
CRITICAL PERIOD	Starts		August 16, 1928			September 1, 1943				November 1, 1936			
	Ends		February 29, 1932			April 30, 1945				April 15, 1937			
	Length (Months)		42.5 Months			20 Months				5.5 Months			
	Study Identification		07-41			07-42				07-13			

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

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

3/ 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

COMPUTATION OF CANADIAN ENTITLEMENT FOR 2006-07 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S. (From 07-42)
B. Optimum Power Generation in the U.S. Only (From 07-12)

Determination of Dependable Capacity Credited to Canadian Storage (MW)	**CAPACITY ENTITLEMENT**	
	(A)	(B)
Step II - Critical Period Average Generation 1/	9020.0	9020.0
Step III - Critical Period Average Generation 2/	7135.1	7135.1
Gain Due to Canadian Storage	1884.9	1884.9
Average Critical Period Load Factor in percent 3/	75.74	75.74
Dependable Capacity Gain 4/	2488.6	2488.6
Canadian Share of Dependable Capacity 5/	1244.3	1244.3

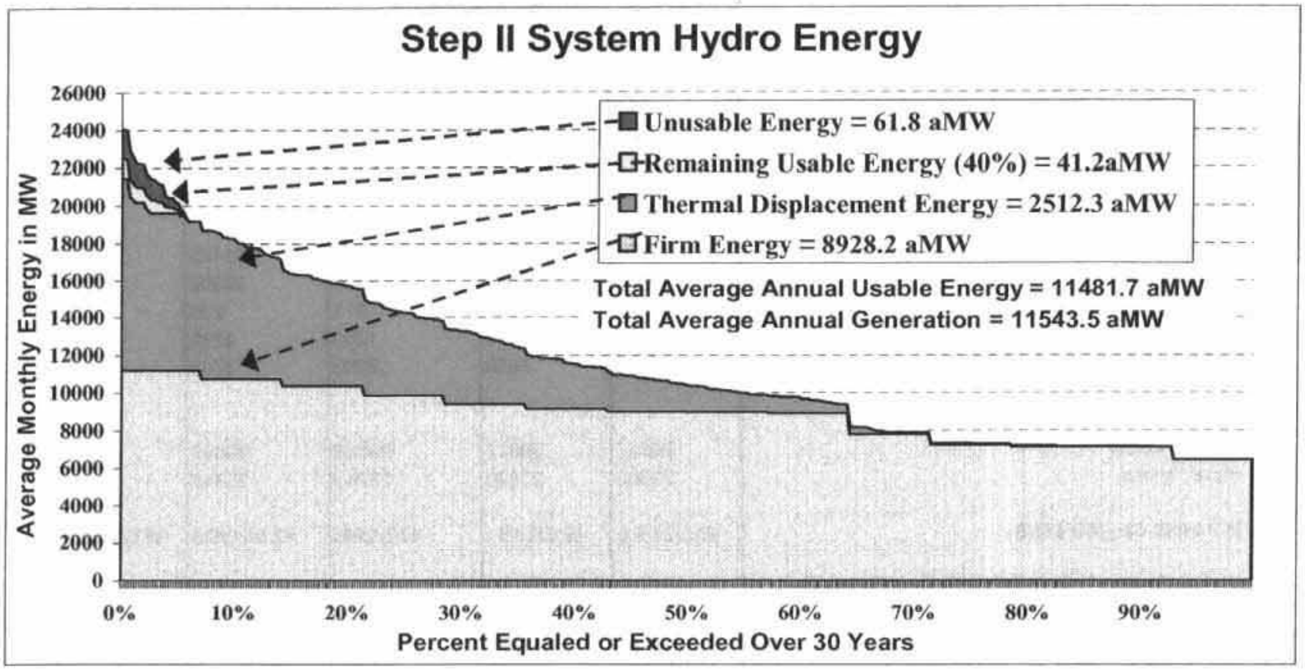
Determination of Increase in Average Annual Usable Hydro Energy (aMW)	**ENERGY ENTITLEMENT**	
Step II (with Canadian Storage) 1/	(A)	(B)
Firm Energy 6/	8928.2	8928.2
Thermal Displacement Energy 7/	2512.3	2509.1
Remaining Usable Energy 8/	41.2	41.3
System Average Annual Usable Energy	11481.7	11478.6
Step III (without Canadian Storage) 2/		
Firm Energy 6/	6286.9	6286.9
Thermal Displacement Energy 7/	3922.6	3922.6
Remaining Usable Energy 8/	295.2	295.2
System Average Annual Usable Energy	10504.7	10504.7
Average Annual Usable Energy Gain 9/	977.0	973.9
Canadian Share of Average Annual Energy Gain 5/	488.5	487.00

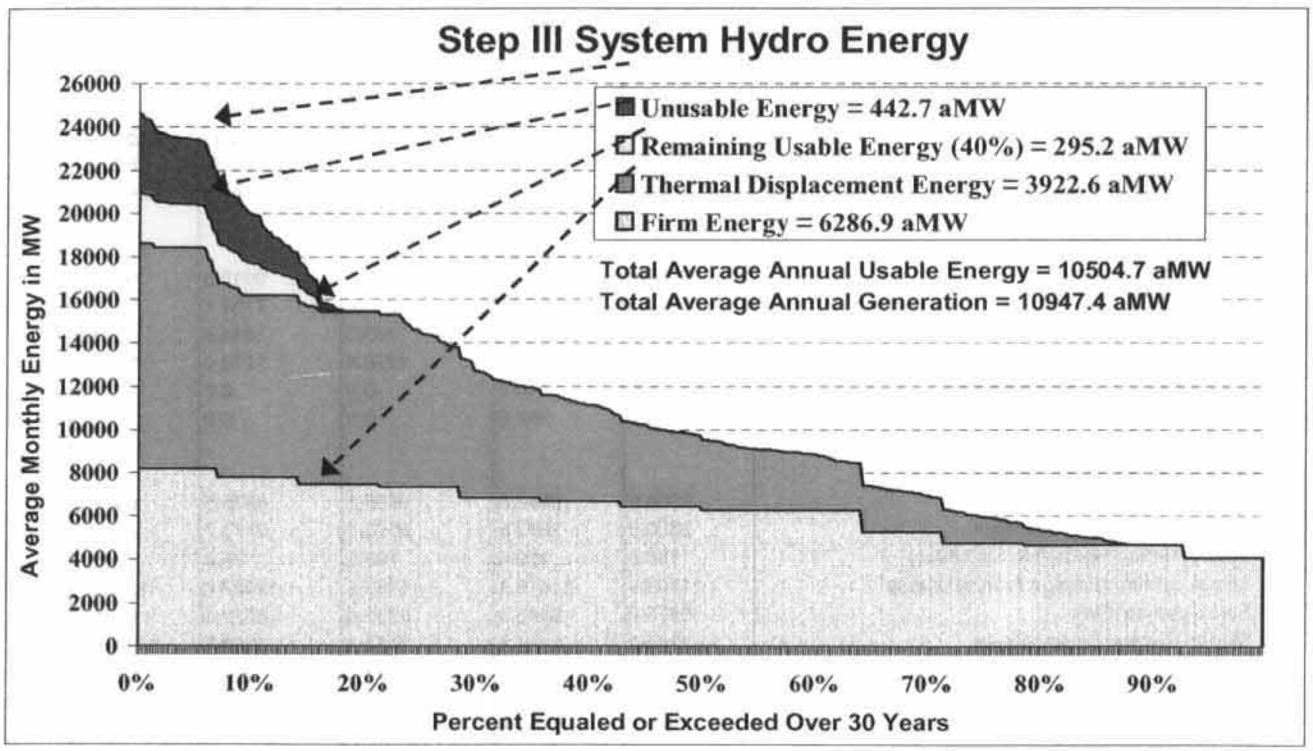
1/ Step II values were obtained from the 07-12 studies for Capacity Entitlement, and the Streamline Method for Energy Entitlement.
2/ Step III values were obtained from the 07-13 study, Table 3 for Capacity Entitlement, and the Streamline Method for Energy Entitlement.
3/ Critical period load factor 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 does include 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

	2001-02	2002-03	2003-04 2004-05 1/	2005-06	2006-07
AVERAGE PNWA ENERGY LOAD					
Annual Load (MW)	21641.7	21769.7	21872.9	22214.7	23734.4
Annual/January Load (%)	88.0	88.0	88.1	88.2	87.4
Critical Period (CP) Load Factor (%)	76.7	76.4	74.9	76.5	75.7
Annual Firm Exports 2/	1156.3	1317.3	1322.1	1073.5	867.6
Annual Firm Surplus (MW) 3/	313.7	323.7	374.7	876.9	701.2
THERMAL INSTALLATIONS (MW) 4/					
January Peak Capability	11433	11545	11312	11486	11946
CP Energy	9496	10081	10053	10302	10587
CP Minimum Generation	853	622	611	230	231
Average Annual System Export Sales	997	1419	1203	1232	353
Average Annual Displaceable Market	7493	7958	8166	8785	9926
HYDRO CAPACITY (MW)					
Total Installed	29827	29827	29689	29689	29689
Base System	23880	23880	23742	23742	23742
STEP I/II/III CP (MONTHS)	42.5/20/6.5	42.5/20/6	42.5/20/6	42.5/20/5.5	42.5/20/5.5
BASE STREAMFLOWS AT THE DALLES (cfs) 5/					
Step I 50-yr. Average Streamflow	181663	181663	181663	181663	181663
Step I CP Average	114401	114401	114401	114401	114401
Step II CP Average	101525	101525	101525	101525	101525
Step III CP Average	58482	64878	64878	57184	57184
BASE STREAMFLOWS AT THE DALLES (m^3/s) 5/					
Step I 50-yr. Average Streamflow	5144.12	5144.12	5144.12	5144.12	5144.12
Step I CP Average	3239.47	3239.47	3239.47	3239.47	3239.47
Step II CP Average	2874.87	2874.87	2874.87	2874.87	2874.87
Step III CP Average	1656.01	1837.14	1837.14	1619.26	1619.26
CAPACITY BENEFITS (MW)					
Step II CP Generation	9055.6	9049.2	8964.6	9018.5	9020.0
Step III CP Generation	6865.3	7260.6	7201.6	7154.1	7135.1
Step II Gain over Step III	2190.3	1788.6	1763.0	1864.4	1884.9
CANADIAN ENTITLEMENT	1427.1	1170.7	1176.4	1218.0	1244.3
Change due to Mica Reoperation	0.0	-0.7	-0.9	0.0	0.0
Benefit in Sales Agreement	187.0	167.0	0.0	0.0	0.0
ENERGY BENEFITS (aMW)					
Step II Annual Firm	8966.5	8942.9	8855.1	8875.5	8928.2
Step II Thermal Displacement	2306.6	2343.6	2395.1	2473.7	2512.3
Step II Remaining Usable Secondary	135.8	129.6	105.3	78.6	41.2
Step II System Average Annual Usable	11408.9	11416.1	11355.5	11427.8	11481.7
Step II Annual Firm	6573.9	6448.1	6392.4	6272.1	6286.9
Step II Thermal Displacement	3294.0	3431.4	3455.4	3688.7	3922.6
Step II Remaining Usable Secondary	475.9	467.7	433.1	396.7	295.2
Step II System Average Annual Usable	10343.8	10347.2	10280.9	10357.5	10504.7
CANADIAN ENTITLEMENT	532.6	534.5	537.3	535.1	488.5
Change due to Mica Reoperation	0.4	1.7	-1.1	1.8	1.5
ENTITLEMENT in Sales Agreement	95.0	93.0	0.0	0.0	0.0
STEP II PEAK CAPABILITY (MW)	32501	32544	32062	32323	32607
STEP II PEAK LOAD (MW)	27650	28734	28924	28608	30550
STEP III PEAK CAPABILITY (MW)	32260	32352	31867	32174	32488
STEP III PEAK LOAD (MW)	24034	24949	25141	23394	24874

CHART 1
2006-07 DDPB STUDIES
DURATION CURVES OF 30 YEARS MONTHLY HYDRO GENERATION (aMW)





FOOTNOTES FOR TABLE 6

1. The 2004-05 AOP/DDPB utilize the same system regulation studies as were utilized for the 2003-04 AOP/DDPB.

2. Average annual firm exports do not include the firm surplus shape or the new thermal installation power used outside the Region (exports to shape thermal installations), but does include plant sales.

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

AOP Study	Amount Shaped (MW)
2001-02	1877 May and June.
2002-03	1937 May and June.
2003-04 & 2004-05	1491 May through July.
2005-06	700 Aug, 600 Sep, 2070 April 30, 3740 May, 2540 June, and 1845 July.
2006-07	766 Aug15, 774 Aug 31, 1171 Sep, 634 Apr 30, 2210 May, 1870 June, and 2026 July.

4. For 2001-02 through 2005-06 DDPB studies, the thermal installations include thermal imports, all existing and planned thermal resources, combustion turbines, cogeneration, renewable thermal, thermal PURPA/NUGS, minus seasonal exchange imports and plant sales. Beginning with the 2006-07 DDPB, thermal installations include Columbia Generating Station and a generic thermal installation sized as needed to meet the Step I load.

5. The 1990 level modified flows were used and no additional irrigation depletions were anticipated for the 2006-07 level. There is, however, an adjustment for Grand Coulee pumping and return flow.