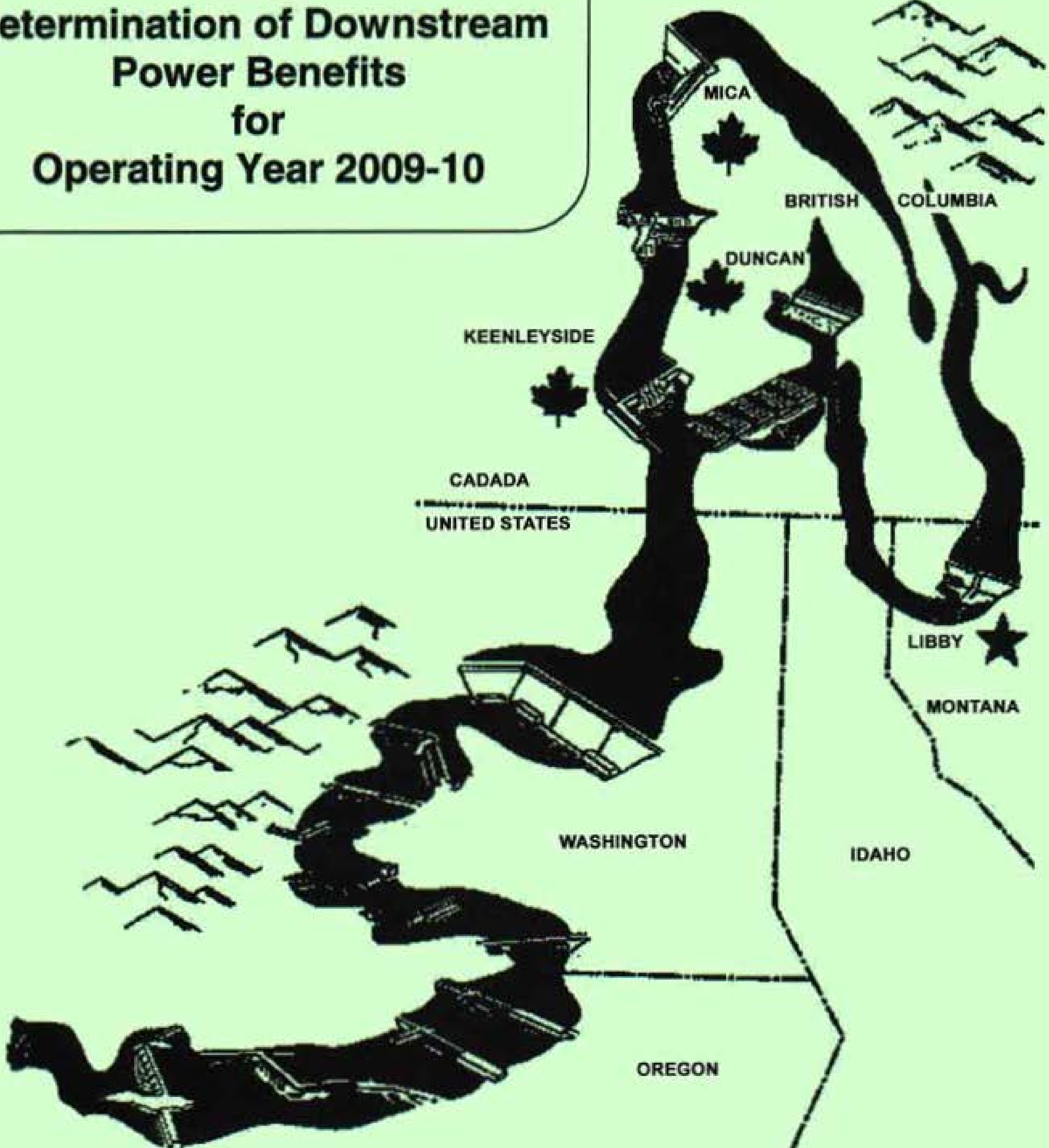
COLUMBIA RIVER TREATY
Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2009-10



Columbia River Treaty Operating Committee

November 2004

COLUMBIA RIVER TREATY ENTITY AGREEMENT ON THE ASSURED OPERATING PLAN AND DETERMINATION OF DOWNSTREAM POWER BENFITS FOR THE 2009-10 OPERATING YEAR

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

The Entities agree that the attached reports entitled "Columbia River Treaty Hydroelectric Operating Plan: Assured Operating Plan for the Operating Year 2009-10" and "Columbia River Treaty Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2009-10," both dated November 2004, shall be the Assured Operating Plan and Determination of Downstream Power Benefits for the 2009-10 Operating Year.

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

Executed for the Canadian Entity this 6th day of December, 2004.

By ____________________
Robert G. Elton
Chair

Executed for the United States Entity this 30th day of November, 2004.

By ____________________
Stephen J. Wright
Chairman

By ____________________
Brigadier General William T. Grisoli
Member

COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
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HYDROELECTRIC OPERATING PLAN
ASSURED OPERATING PLAN
FOR OPERATING YEAR 2009-10

November 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 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 2009-10 AOP (AOP10) 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/DDPBs, and Operating Procedures for the 2001-02 and Future AOPs," 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, including the update to Appendix 1, dated 18 November 2003, and the November 2004 additions of Appendix 6, Streamline Procedures, and Appendix 7, Table of Median Streamflows.

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 use only the first of the three Streamline Procedures, "Forecasting Loads and Resources," as defined in Appendix 6 of the POP.

In accordance with Protocol VII(2), this AOP provides a reservoir-balance relationship for each month for the whole of the 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 (AOP10-41) 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 the AOP were based on 2009-10 operating year estimated loads and resources in the USA Pacific Northwest (PNW) Area, including estimated flows of power from and to adjacent areas, and hydro resources in the Columbia River Basin in British Columbia. In accordance with Protocol VIII, the AOP10 is based on a 30-year streamflow period and the Entities have agreed to use an operating year of 1 August to 31 July. The studies used historical flows for the period August 1928 through July 1958, modified by estimated irrigation depletions for the 2000 level and including the latest Grand Coulee pumping requirements.[6] The 2000 level was considered the best estimate of irrigation depletions for the 2009-10 operating year at the time the AOP10 studies were initiated.

The CRCs 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. Brownlee was operated to the fixed critical period operation used in prior AOPs.

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 URCs.

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 (Joint Optimum), compared to an operation for optimum power only in the USA (USA Optimum), 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 in the Joint Optimum Study was designed to achieve a weighted sum of these three quantities that was greater than the weighted sum achieved in the USA Optimum Study.

In order to measure optimum power generation for the AOP10, 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 Joint Optimum Study compared to the USA Optimum Study. 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 regulation studies 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 3.9 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 DDPB10, columns A and B.)

Since there is no reduction in entitlement, the Entities have determined in Section 3 of the 2009-10 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 2009-10 Operating Year shall be guided by the ORCs and CRCs for the whole of Canadian Treaty Storage, Flood Control Curves for the individual projects, and operating rules for specific projects. The ORCs and CRCs 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 ORCs 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 ORCs as defined in subsection 4(b). The CRCs are adjusted for crossovers at each project by the hydroregulation model as defined in Section 2.3.A of the POP. The CRCs for Duncan, Arrow, Mica, and the Composite CRCs for the whole of Canadian Treaty Storage are tabulated 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 ARCs and VRCs, and supporting data used in determining the ARCs and VRCs for Mica, Arrow, and Duncan are provided in Tables 4-6, respectively.

(1) Assured Refill Curve

The ARCs indicate the minimum August through June end-of-period storage contents required to meet firm load and refill the Coordinated

System storage by 31 July, based on the 1930-31 inflows. The upstream storage requirements and the power discharge requirements (PDRs) 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 VRCs 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, PDRs, and VRC lower limits (VRCLLs) 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 PDRs and VRCLLs 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 PDRs and VRCLLs 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 VRCs for Mica, Arrow, and Duncan for the 30-year streamflow period. In actual operation in 2009-10, the PDRs and VRCLLs will be based on the forecast of unregulated runoff at The Dalles.

c) Operating Rule Curve Lower Limit (ORCLL)

The ORCLLs (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 ORCLLs 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 ORCLLs. The ORCLLs are developed for 1936-37 water conditions which include the lowest January through April unregulated streamflows at The Dalles during the 30-year streamflow period. The ORCLLs for Mica, Arrow, and Duncan are shown in Tables 4-6 respectively.

d) Upper Rule Curve (Flood Control)

The URCs indicate the end-of-period storage content to which each individual Canadian Treaty Storage project shall be evacuated for flood control. The URCs used in the studies were based upon Flood Control Storage Reservation

Diagrams contained in the FCOP and analysis of system flood control simulations. URCs 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 URCs will be computed as outlined in the FCOP using the latest forecast of runoff available at that time.

e) Operating Rule Curve

The ORCs 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 ORCs 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 water conditions.

4. Operating Rules

The AOP10-41 System Regulation Study was used to develop and test the operating rules and rule curves. It contains the agreed-upon ORCs and CRCs, 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 AOP10-41 System Regulation Study will apply to the operation of Canadian Treaty Storage in the 2009-10 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 Section 2.4(c) of the POP.

c) Canadian Treaty Project Operating Criteria

In this AOP, Mica and Arrow reservoirs will be operated in accordance with operating criteria listed in Tables 1 and 1.1, respectively, so as to optimize generation at site, downstream at Revelstoke and Keenleyside, and downstream in the USA. Under these operating criteria, outflows will be increased as required to avoid storage above the URC at either reservoir.

(1) Mica Project Operating Criteria

In general, the Mica operation in each period is determined by Arrow's storage content at the end of the previous period. 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.

(2) Arrow Project Operating Criteria (APOC)

In general, Arrow reservoir will be operated to provide the balance of the required whole of Canadian Treaty Storage as described in 4(a) or 4(b) above, subject to physical and operating constraints. These constraints include, but are not limited to, the URC, rate-of-draft and minimum flows limits, and the operating criteria shown in Table 1.1a (APOC).

Under the APOC, Arrow's operation will be limited, under all water conditions, to a maximum outflow of 2,011 m^3/s (71,000 cfs) in January and 1,699 m^3/s (60,000 cfs) in February, subject to flood control requirements. Maximum storage levels in February through June may apply depending on the forecast for The Dalles residual unregulated runoff for the current month through July. Table 1.1(a) shows the criteria to determine the maximum storage levels for Arrow.

Table 1.1(b) shows the maximum storage levels for the 30-year streamflow period used in AOP10, and which were based on the criteria in Table 1.1(a).

APOC Implementation: In the Detailed Operating Plan, the default implementation of the APOC will use the distribution factors shown in Table 1.1(c). These distribution factors are multiplied by the current month through July forecast volumes at The Dalles, to calculate future month through July volume forecasts. The resulting residual month-July volumes are then used to determine the maximum storage levels from the criteria provided in Table 1.1a. To assist implementation of this new procedure, an example is shown at the bottom of Table 1.1(c).

d) Other Canadian Project Operation

Revelstoke, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile, and Waneta are included in the AOP10 as run-of-river projects. Generation at Arrow is modeled in the studies. Corra Linn and Kootenay Canal are included and operated in accordance with criteria that closely approximate International Joint Commission rules for Kootenay Lake.

5. Preparation of the Detailed Operating Plan

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 DOPs 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 2009-10 DOP (DOP10) 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 DOP10. Failing agreement on updating the data and/or criteria, the DOP10 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 2009-10 Operating Year shall be guided by the DOP10.

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 2009-10."

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 2009 through 31 July 2010 period covered by this AOP, and includes transmission losses and scheduling guidelines for delivery of the Canadian Entitlement.

7. Summary of Changes from the 2008-09 AOP and Notable Assumptions

Data from the recent AOPs are compared and summarized in Table 11. An explanation of the more important changes and notable assumptions follows.

a) Loads

Loads for the AOP10 were based on Bonneville Power Administration's (BPA) 2002 White Book (WB02) medium-case load forecast, dated December 2002 and published in November 2003. This load forecast showed a large 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 AOP10 is 2,227 aMW (9.1%) less than the 2008-09 AOP (AOP09). After this AOP was started in January 2004 there have been two new regional load forecasts. The BPA WB03 forecast for operating year 2009-10, dated December 2003 and published in July 2004, is 4.9% lower than the WB02. However, the Northwest Power and Conservation Council's Fifth Power Plan regional load forecast, published in September 2004, is about 2.5% higher than the WB02 for the 2009-10 operating year. Other load assumptions and changes include:

- It was assumed that one-half of the Canadian Entitlement was exported to British Columbia, and the remaining one-half was disposed in the USA. The estimated disposition of the Entitlement in the Step I system was based on a forecast of the 2009-10 Energy Entitlement from BPA's WB02. The estimated and the computed Canadian Entitlement are shown below:

During 1 August 2009 – 31July 2010

Canadian Entitlement Return	Energy (aMW)		Capacity (MW)	
	Estimated	Computed	Estimated	Computed
Export to BC (1/2)	262.0	283.6	588.0	676.1
Retained in PNW (1/2)	262.0	283.6	588.0	676.1
Total	524.0	567.1	1176.0	1352.3

Iterative studies to update the Canadian Entitlement in the load estimate were not performed because the effect on the amount of thermal installations is less than one-fourth of one percent and therefore would not significantly affect the results of the studies.

- Compared to the AOP09, Flows-Out (exports that are mostly to the southwest) decreased by 134 aMW, mainly due to expiration of several firm contracts. Flows-In (imports) decreased by 26 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 33 aMW decrease in Miscellaneous Non-Thermal Resources, mainly wind generators.

b) Thermal Installations

Because of increasing difficulty in forecasting Thermal Installations, the Entities used the Streamline Procedure for "Loads and Resources" for determining Thermal Installations, as used in the 2006-07, 2007-08, and 2008-09 AOPs. The procedure assumes 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 Installation 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, so CGS maintenance was not included in the 2009-10 study. Because of the large decrease in PNW Area firm load and a decrease in exports minus imports, the Thermal Installations decreased by 2,304 aMW compared to the AOP09.

c) Hydro Project Modified Streamflows

- The base unregulated streamflows used in the System Regulation Studies were updated from the 1990 level used in the previous AOP/DDPB studies to the 2000 Modified Streamflows published by BPA in May 2004. Modified Streamflows are determined from historic observed streamflows, adjusted to remove the storage regulation effect at modeled upstream projects, and modified to a common level of irrigation depletions and reservoir evaporation. Total irrigation depletions changed slightly. The 60-year average Modified Flow at The Dalles increased by about 0.46%, mainly due to decreased depletions on Yakima and Deschutes rivers. Grand Coulee pumping estimates were updated from the February 2001 Pacific Northwest Coordination Agreement (PNCA) data submittal by the Bureau of Reclamation (Bureau). The Grand Coulee return flows were also updated to reflect the difference between the Bureau update and the 2000 level Modified Flows.

- The Step I base streamflow file now contains 82 projects with the addition of Lime Point to simplify the calculation of Brownlee minimum flow requirement.

d) Hydro Project Rule Curves

The critical rule curves, refill curves, and Mica/Arrow operating criteria were updated in accordance with procedures defined in the POP, except that the VRCLLs were not updated from the 2005-06 AOP. However, Grand Coulee's 80 Maf VRCLL was raised to the CRC1 for February through 15 April, and Duncan's 80 Maf VRCLL was raised to the CRC1 for January, after the refill study, to eliminate crossovers between the CRC1 and ORC. Other changes and notable assumptions include:

- The agreed allocation of flood control space in Mica and Arrow was 5.03 and 4.44 km^3 (4.08 and 3.6 Maf), respectively. The URC data was the same as used in the 2006-07, 2007-08, and 2008-09 AOPs. In the 2005-06 and prior AOPs 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(c)2 was changed from the three prior AOPs. APOC is implemented through use of maximum outflows and maximum storage limits.

- Distribution factors for Dworshak, Grand Coulee, Hungry Horse, and Libby, and the forecast error for Libby, both used in the calculation of variable refill curves, were updated.

- Power Discharge Requirements were developed without the adjustment to the VRCLL to avoid crossovers. The VRCLL adjustment was made after the Refill Study.

- The Brownlee storage operation outside the critical period was simulated by using CRCs and ORCs instead of the fixed operation from Idaho Power Company (IPC) used in the 2003-04 and previous AOPs. The CRCs were based on 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. ORCs were revised from the AOP09 to more closely follow the historic forecast of IPC operation while including the updated 2000 level modified flows and Lime Point minimum flow requirements.

- Coeur d'Alene Lake flood control was updated.

e) Hydro Project Operating Procedures and Constraints

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. Nonpower constraints for non-Base System projects are updated to current requirements, except for Libby, which uses the values specified in the February 2000 Libby Coordination Agreement. Changes from the prior AOP include:

- Brownlee minimum flow requirements were changed to 166 m^3/s, (5,850 cfs) in all periods plus the flow needed to reach 368 m^3/s (13,000 cfs) at Lime Point during July through September.
- Generation plant data tables for Noxon were updated.
- Lower Granite, Little Goose, and Lower Monumental average monthly fish spill and spill caps were updated for April 15 through June. All data increased except the average fish spill at Lower Monumental decreased.
- Generation plant data tables for Arrow and Brilliant were updated. These changes did not significantly affect the system operation.
- Long Lake draft rate of 0.3 m (1.0 ft) per day submitted by Avista was included.
- Priest Lake maximum elevation was set to empty to support fish spawning in October.
- The volume runoff file used to compute Lower Granite fish flow augmentation objectives was updated to the 2000 Modified Flows.
- As in the AOP09, Tacoma's storage projects (Mossyrock, Cushman 1 and Alder) are set to the operation from the 2006 AOP instead of modeling as hydro independents because they were removed as coordinated resources in PNCA Planning.
- The White River project is off-line, but the reservoir remains, so the generation was zero.
- The Hydro-independents were not updated for the 2000 Modified Flows.

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 May 2003.

4 "BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 10-41," dated 10 October 2004.

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 2000 Level Modified Streamflow, 1928 to 1999, Columbia River and Coastal Basins, prepared by BPA," dated May 2004.

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
2009-10 ASSURED OPERATING PLAN

	Target Operation			Target Operation Limits		
Month	End of Previous Month **Arrow** Storage Content (ksfd)	Month Outflow (cfs)	End-of-Month Treaty Storage Content 1/ (ksfd)	Minimum Treaty Storage Content 2/ (ksfd)	Maximum Outflow 1/ (cfs)	Minimum Outflow (cfs)
August 1-15	3,500 - FULL	-	3,454.2	-	34,000	15,000
	2,520 - 3,500	25,000	-	0	-	15,000
	0 - 2,520	32,000	-	0	-	15,000
August 16-31	2,500 - FULL	-	3,529.2	-	34,000	15,000
	2,000 - 2,500	25,000	-	0	-	15,000
	0 - 2,000	32,000	-	0	-	15,000
September	3,570 - FULL	-	3,529.2	-	34,000	10,000
	3,210 - 3,570	22,000	-	0	-	10,000
	2,300 - 3,210	27,000	-	0	-	10,000
	0 - 2,300	32,000	-	0	-	10,000
October	3,570 - FULL	-	3,428.4	-	34,000	10,000
	3,180 - 3,570	19,000	-	0	-	10,000
	500 - 3,180	22,000	-	0	-	10,000
	0 - 500	32,000	-	0	-	10,000
November	3,150 - FULL	22,000	-	0	-	10,000
	3,100 - 3,150	19,000	-	0	-	10,000
	410 - 3,100	25,000	-	0	-	10,000
	0 - 410	32,000	-	0	-	10,000
December	2,860 - FULL	25,000	-	204.1	-	10,000
	1,520 - 2,860	27,000	-	204.1	-	10,000
	600 - 1,520	22,000	-	204.1	-	10,000
	0 - 600	32,000	-	204.1	-	10,000
January	2,700 - FULL	23,000	-	154.1	-	12,000
	2,500 - 2,700	26,000	-	154.1	-	12,000
	2,150 - 2,500	28,000	-	154.1	-	12,000
	0 - 2,150	30,000	-	154.1	-	12,000
February	1,500 - FULL	20,000	-	0	-	12,000
	1,230 - 1,500	21,000	-	0	-	12,000
	1150 - 1,230	23,000	-	0	-	12,000
	0 - 1,150	26,000	-	0	-	12,000
March	1100 - FULL	17,000	-	0	-	12,000
	320 - 1100	19,000	-	0	-	12,000
	40 - 320	24,000	-	0	-	12,000
	0 - 40	21,000	-	0	-	12,000
April 1-15	990 - FULL	18,000	-	0	-	12,000
	860 - 990	19,000	-	0	-	12,000
	80 - 860	14,000	-	0	-	12,000
	0 - 80	19,000	-	0	-	12,000
April 16-30	850 - FULL	11,000	-	0	-	10,000
	500 - 850	13,000	-	0	-	10,000
	20 - 500	10,000	-	0	-	10,000
	0 - 20	17,000	-	0	-	10,000
May	650 - FULL	10,000	-	0	-	8,000
	500 - 650	8,000	-	0	-	8,000
	160 - 500	10,000	-	0	-	8,000
	0 - 160	8,000	-	0	-	8,000
June	2,200 - FULL	10,000	-	0	-	8,000
	1,100 - 2,200	8,000	-	0	-	8,000
	620 - 1,100	16,000	-	0	-	8,000
	0 - 620	10,000	-	0	-	8,000
July	2,550 - FULL	-	3,436.2	-	34,000	10,000
	1,520 - 2,550	19,000	-	0	-	10,000
	0 - 1,520	31,000	-	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 1.1a
(English Units)
ARROW PROJECT OPERATING CRITERIA
2009-10 ASSURED OPERATING PLAN

Period	Volume Runoff Period	The Dalles Volume Runoff (Maf)	Maximum Storage Limit 1/ 2/ (ksfd)	Maximum Outflow Limit 3/ (cfs)
January			URC	71,000
February	1 Feb - 31 Jul	≤ 70	URC	60,000
		>70 to <80	URC to 1800	
		≥ 80	1800	
March	1 Mar - 31 Jul	≤ 65	URC	
		>65 to <75	URC to 900	
		≥ 75	900	
April 15	1 Apr - 31 Jul	≤ 61	URC	
		>61 to <70	URC to 900	
		≥ 70	900	
April 30	1 Apr - 31 Jul	≤ 61	URC	
		>61 to <70	URC to 1000	
		≥ 70	1000	
May	1 May - 31 Jul	≤ 68	URC	
		>68 to <70	URC to 1800	
		≥ 70	1800	
June	1 Jun - 31 Jul	≤ 33	URC	
		>33 to <35	URC to 3300	
		≥ 35	3300	

Notes:

1/ If the Maximum Storage Limit is computed to be above the URC, then the URC will apply.

2/ Interpolate when there are two values. For example, if the February-July volume runoff is between 70 Maf and 80 Maf, then the Maximum Storage Limit is interpolated between February's URC and 1800 ksfd.

3/ The Maximum Average Monthly Outflow Limit takes precedence over the Maximum Storage Limit. However, the Maximum Outflow Limit may be exceeded to avoid storage above the URC.

TABLE 1.1b
(English Units)
ARROW PROJECT OPERATING CRITERIA
FOR 2009-10 ASSURED OPERATING PLAN

Maximum Average Monthly Flow Limits (cfs)

Period	JAN	FEB
Flow Limit	71,000	60,000

End-of-Period Maximum Storage Limits (ksfd)

Year	FEB	MAR	APR15	APR30	MAY	JUN
1928-29	URC	URC	URC	URC	URC	3456.1
1929-30	URC	URC	URC	URC	URC	URC
1930-31	URC	URC	URC	URC	URC	URC
1931-32	1800.0	900.0	900.0	1000.0	1800.0	3300.0
1932-33	1800.0	900.0	900.0	1000.0	1800.0	URC
1933-34	1800.0	900.0	900.0	1000.0	URC	URC
1934-35	1800.0	900.0	900.0	1000.0	URC	URC
1935-36	1800.0	900.0	900.0	1000.0	URC	URC
1936-37	URC	URC	URC	URC	URC	3422.4
1937-38	1800.0	900.0	900.0	1000.0	1800.0	URC
1938-39	1937.3	932.1	1178.5	1257.0	URC	URC
1939-40	1991.7	1209.8	1956.9	1993.9	URC	URC
1940-41	URC	URC	URC	URC	URC	URC
1941-42	1800.0	900.0	900.0	1000.0	URC	3300.0
1942-43	1800.0	900.0	900.0	1000.0	1800.0	URC
1943-44	URC	URC	URC	URC	URC	URC
1944-45	1853.8	968.2	1026.9	1116.6	URC	3300.0
1945-46	1800.0	900.0	900.0	1000.0	1800.0	3300.0
1946-47	1800.0	900.0	900.0	1000.0	1800.0	3300.0
1947-48	1800.0	900.0	900.0	1000.0	1800.0	3300.0
1948-49	1800.0	900.0	900.0	1000.0	2759.9	URC
1949-50	1800.0	900.0	900.0	1000.0	1800.0	URC
1950-51	1800.0	900.0	900.0	1000.0	1800.0	3300.0
1951-52	1800.0	900.0	900.0	1000.0	1800.0	URC
1952-53	1800.0	900.0	900.0	1000.0	1800.0	URC
1953-54	1800.0	900.0	900.0	1000.0	1800.0	URC
1954-55	1800.0	900.0	900.0	1000.0	1800.0	3300.0
1955-56	1800.0	900.0	900.0	1000.0	1800.0	URC
1956-57	1800.0	900.0	900.0	1000.0	1800.0	3300.0
1957-58	1800.0	900.0	900.0	1000.0	1800.0	3300.0

TABLE 1.1c
(English Units)
APOC IMPLEMENTATION: DISTRIBUTION FACTORS FOR THE DALLES
2009-10 ASSURED OPERATING PLAN

Forecast Date	Forecast Period	The Dalles Distribution Factors 1/ Jan-Jul	Feb-Jul	Mar-Jul	Apr-Jul	May-Jul	Jun-Jul
01-Jan	1 Jan - 31 Jul	1.0000	0.9392	0.8589	0.7735	0.7174	0.4393
01-Feb	1 Feb - 31 Jul		1.0000	0.9145	0.8235	0.7638	0.4677
01-Mar	1 Mar - 31 Jul			1.0000	0.9005	0.8352	0.5114
01-Apr	1 Apr - 31 Jul				1.0000	0.9275	0.5679
01-May	1 May - 31 Jul					1.0000	0.6123
01-Jun	1 Jun - 31 Jul						1.0000

Notes:

1/ Unless otherwise agreed, the DOP10 will apply these distribution factors to the monthly volume forecast at The Dalles for computing the Month-July runoff volumes required by the APOC.

2. These distribution factors are calculated from the median 71 year Jan-Jul, Feb-Jul, etc., volumes.

For Example, in the month of May:

	From Table 1.1c		Look up Table 1.1a	
1 May Forecast Forecast Volume = 65 Maf (May-Jul)	The Dalles Distribution Factor	Month-Jul Volume Runoff (Maf)	The Dalles Volume Runoff (Maf)	Maximum Storage Limit (ksfd)
May	1.0000	65.0	≤ 68	URC
June	0.6123	39.8	≥ 35	3300

TABLE 2
COMPARISON OF 2009-10 ASSURED OPERATING PLAN
STUDY RESULTS

Study 10-41 provides Optimum Generation in Canada and in the United States.
Study 10-11 provides Optimum Generation in the United States only.

	Study No. 10-41	Study No. 10-11	Net Gain	Weight	Value
1. Firm Energy Capability (aMW)					
U.S. System 1/	12089.2	12089.5	-0.3		
Canada 2/, 3/	2923.5	2873.3	50.2		
Total	15012.7	14962.8	49.9	3	149.7
2. Dependable Peaking Capacity (MW)					
U.S. System 4/	30323.6	30326.3	-2.7		
Canada 2/, 5/	5669.4	5624.5	44.9		
Total	35993.0	35950.8	42.2	1	42.2
3. Average Annual Usable Secondary Energy (aMW)					
U.S. System 6/	3087.4	3073.6	13.8		
Canada 2/, 7/	255.5	283.7	-28.2		
Total	3342.9	3357.3	-14.4	2	-28.7
			Net Change in Value =		163.2

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)
2009 - 10 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	3529.2	3528.1	3513.8	3405.3	2977.9	2269.0	1474.5	712.4	456.7	142.2	138.4	384.2	2026.3	3045.1
1929-30	3390.2	3515.4	3362.2	2482.1	2035.1	1540.9	583.9	248.7	1.5	1.8	158.8	530.0	1195.3	2582.1
1930-31	2943.0	3270.5	3272.9	2494.4	2088.6	1324.1	763.5	209.7	0.4	0.0	0.0	252.7	974.9	2135.0
1931-32	2035.2	1865.7	1198.7	1051.1	661.9	55.5	4.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	3579.6	3577.7	3204.5	2881.1	2654.6	2378.6	1362.0	829.2	496.2	434.9	416.0	1547.9	3089.7	3499.3
1929-30	3532.0	3557.6	2980.7	2826.0	2007.0	1458.2	479.1	209.4	0.0	0.8	237.0	1324.1	2630.3	3461.4
1930-31	3497.0	3449.1	2942.6	2766.1	1909.8	1437.8	475.1	111.8	0.0	0.0	0.0	1013.0	1872.0	1755.6
1931-32	1775.2	1882.6	1743.0	1166.4	1018.8	193.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	705.8	705.8	688.8	685.3	596.1	462.9	365.3	190.0	124.9	94.4	105.7	223.2	498.0	624.5
1929-30	672.0	662.7	602.6	592.5	599.4	503.4	374.5	170.4	1.9	2.8	32.6	147.3	366.9	583.8
1930-31	660.7	582.3	611.3	639.6	643.0	384.5	188.2	36.0	1.4	0.0	0.0	127.0	92.0	179.2
1931-32	205.5	124.1	122.4	79.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	7814.6	7811.6	7407.1	6971.7	6228.6	5110.5	3201.8	1731.6	1077.8	671.5	660.1	2155.3	5614.0	7168.9
1929-30	7594.2	7735.7	6945.5	5900.6	4641.5	3502.5	1437.5	628.5	3.4	5.4	428.4	2001.4	4192.5	6627.3
1930-31	7100.7	7301.9	6826.8	5900.1	4641.4	3146.4	1426.8	357.5	1.8	0.0	0.0	1392.7	2938.9	4069.8
1931-32	4015.9	3872.4	3064.1	2297.3	1680.7	248.9	4.8	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
2009 - 10 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	392.6	975.6	1578.0	1756.6	1821.9	1838.3	1833.2	1821.7	1828.4	1853.4	1916.7	2153.1	3227.1	3529.2
VARIABLE REFILL CURVES (KSFD)														
1928-29							2445.1	2329.5	2290.2	2295.8	2336.3	2781.7	3303.8	3529.2
1929-30							1422.8	1267.9	1219.1	1242.5	1398.6	2175.6	3020.0	"
1930-31							1680.6	1534.7	1481.3	1483.2	1573.1	2194.5	3094.7	"
1931-32							812.4	673.7	626.9	629.5	746.4	1479.0	2735.3	"
1932-33							662.4	559.2	529.7	530.2	607.4	1321.4	2540.0	"
1933-34							11.9	0.0	0.0	0.0	0.0	1056.3	2785.1	"
1934-35							1359.3	1237.3	1220.0	1240.5	1310.3	1954.8	2865.4	"
1935-36							1146.8	1025.3	996.7	996.8	1091.5	1906.1	3127.8	"
1936-37							2431.8	2295.6	2241.5	2236.1	2324.8	2793.9	3335.4	"
1937-38							1065.3	943.4	896.7	903.7	996.4	1677.3	2812.1	"
1938-39							1475.7	1398.2	1358.6	1386.3	1497.1	2208.0	3322.0	"
1939-40							1257.7	1143.5	1121.3	1142.9	1272.0	2005.1	3082.7	"
1940-41							1865.7	1740.4	1706.4	1727.7	1904.2	2572.9	3317.5	"
1941-42							1860.7	1739.3	1697.2	1695.2	1770.9	2373.8	3194.7	"
1942-43							1660.6	1516.4	1471.3	1469.1	1621.1	2263.0	3026.1	"
1943-44							2537.4	2385.5	2345.1	2348.8	2417.0	2903.5	3475.0	"
1944-45							2449.4	2334.5	2307.8	2322.2	2371.4	2814.4	3386.3	"
1945-46							444.9	292.7	244.2	234.4	325.6	1109.5	2692.0	"
1946-47							632.4	533.9	514.2	526.1	642.5	1444.0	2803.0	"
1947-48							507.6	388.4	353.7	339.4	419.2	1165.7	2646.9	"
1948-49							2405.7	2261.1	2199.3	2196.8	2273.8	2743.2	3529.2	"
1949-50							863.0	704.5	646.0	636.5	720.9	1386.9	2458.3	"
1950-51							854.3	743.4	716.9	725.2	838.7	1506.0	2819.7	"
1951-52							1261.1	1107.5	1055.6	1040.5	1121.8	1801.4	2967.1	"
1952-53							1627.1	1491.4	1449.0	1446.7	1506.0	2041.4	2983.1	"
1953-54							418.1	294.6	276.9	280.6	364.1	1081.9	2430.4	"
1954-55							1522.2	1414.7	1388.8	1399.1	1485.2	2072.0	2824.3	"
1955-56							726.3	601.2	554.5	547.6	636.0	1404.0	2734.3	"
1956-57							894.9	762.5	730.5	735.7	824.7	1490.1	3064.9	"
1957-58							780.4	660.9	635.4	646.0	751.0	1438.7	2857.5	"
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	3000	20439	24336	46748
VARIABLE REFILL CURVES					80 MAF		3000	3000	3000	3000	3000	3000	25000	37000
(BY VOLUME RUNOFF AT THE DALLES)					95 MAF		3000	3000	3000	3000	3000	3000	24000	36000
					110 MAF		3000	3000	3000	3000	3000	3000	18000	28000
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)							364.0	108.9	0.1	0.0				

Note: These PDRs do not reflect the update to the VRCLL to avoid crossovers. VRCLL adjustment was made after the Refill Study.

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
2009 - 10 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	0.0	0.0	649.4	1130.2	1162.9	1244.5	1325.2	1494.0	2840.3	3364.5	3579.6
VARIABLE REFILL CURVES (KSFD)														
1928-29							2367.5	2165.3	2028.3	1984.0	2103.8	3126.2	3113.3	3579.6
1929-30							1098.0	1066.4	1069.3	1085.5	1348.0	2509.8	3110.0	"
1930-31							1343.3	1274.3	1218.1	1229.7	1407.9	2363.7	3055.6	"
1931-32							4.0	0.0	17.5	5.1	8.2	941.8	2743.3	"
1932-33							2.3	0.0	17.2	0.8	5.3	1000.7	2710.3	"
1933-34							2.0	0.0	17.2	0.0	4.7	1456.4	3075.6	"
1934-35							441.4	448.3	516.8	551.8	729.4	1806.5	2969.7	"
1935-36							552.6	462.7	376.2	354.6	515.2	1847.1	2990.5	"
1936-37							2675.8	2429.3	2281.9	2209.2	2350.7	3301.7	3210.6	"
1937-38							240.7	216.4	192.8	236.3	454.0	1542.9	2890.7	"
1938-39							1251.1	1163.1	1104.2	1089.8	1324.7	2429.8	3263.4	"
1939-40							993.9	965.4	973.8	1072.5	1343.3	2357.1	3123.2	"
1940-41							1824.3	1751.8	1713.9	1828.6	2145.3	3413.1	3434.1	"
1941-42							1674.0	1607.4	1795.8	1777.4	2035.3	2789.8	3109.2	"
1942-43							1337.8	1253.4	1194.1	1162.9	1362.5	2590.1	3435.1	"
1943-44							3186.5	2994.1	2870.1	2800.8	2962.6	3579.6	3579.6	"
1944-45							2507.1	2359.6	2260.6	2244.8	2382.0	3280.8	3346.6	"
1945-46							2.0	0.0	17.2	0.0	4.7	966.5	2785.8	"
1946-47							144.5	36.8	17.5	33.2	277.4	1478.7	2879.6	"
1947-48							2.0	0.0	17.2	0.0	4.7	1082.3	2812.3	"
1948-49							1281.9	1097.2	1364.2	1356.7	1644.9	2494.1	3467.9	"
1949-50							2.0	0.0	17.2	0.0	4.7	1004.1	2703.8	"
1950-51							79.6	63.9	65.1	41.1	278.2	1360.6	2956.1	"
1951-52							112.0	56.5	35.9	20.2	198.5	1408.6	2927.5	"
1952-53							589.9	540.9	513.6	508.4	686.8	1815.2	2901.9	"
1953-54							2.0	0.0	17.2	0.0	4.7	900.0	2713.0	"
1954-55							264.5	271.2	270.0	256.4	474.7	1573.1	2904.7	"
1955-56							2.0	0.0	17.2	0.0	4.7	1078.4	2815.9	"
1956-57							"	"	"	"	"	934.4	2947.3	"
1957-58							3.5	0.0	17.4	3.9	7.4	1025.4	2849.5	"
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	5000	18016	61159	72118
VARIABLE REFILL CURVES					80 MAF		5000	5000	5000	5000	5000	5000	53000	54000
(BY VOLUME RUNOFF AT THE DALLES)					95 MAF		5000	5000	5000	5000	5000	5000	51000	51000
					110 MAF		5000	5000	5000	5000	5000	5000	27000	44000
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)							293.7	58.2	0.0	0.0				

Note: These PDRs do not reflect the update to the VRCLL to avoid crossovers. VRCLL adjustment was made after the Refill Study.

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
2009 - 10 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	3.7	64.1	130.4	161.1	178.6	189.8	199.9	209.1	223.2	234.1	249.7	406.1	554.9	705.8
VARIABLE REFILL CURVES (KSFD)														
1928-29							365.3	288.5	285.5	284.0	300.7	398.2	598.4	705.8
1929-30							"	286.5	283.2	281.5	305.8	418.7	"	"
1930-31							"	232.3	232.6	235.8	258.7	368.2	"	"
1931-32							9.3	3.0	2.9	0.0	7.7	152.9	471.5	"
1932-33							6.5	0.5	0.7	"	3.7	108.1	446.6	"
1933-34							5.9	0.0	0.3	"	33.0	230.9	540.7	"
1934-35							91.3	22.9	25.4	26.0	50.4	226.9	537.0	"
1935-36							128.1	25.3	30.4	24.4	57.5	239.9	545.2	"
1936-37							365.3	223.4	222.3	220.9	242.0	353.2	598.4	"
1937-38							8.0	1.8	1.9	6.6	36.9	201.4	499.0	"
1938-39							311.7	72.2	73.8	77.6	109.5	304.3	586.4	"
1939-40							315.6	64.3	73.6	86.9	121.4	305.7	587.3	"
1940-41							365.3	148.8	153.9	169.0	214.6	357.5	598.4	"
1941-42							121.4	128.3	133.3	137.2	166.7	303.6	545.5	"
1942-43							116.9	116.5	120.1	122.5	161.4	308.9	526.5	"
1943-44							365.3	299.3	300.8	301.3	325.1	425.4	610.0	"
1944-45							280.0	216.8	219.5	220.6	238.9	348.5	579.3	"
1945-46							5.9	0.0	0.3	0.0	2.9	105.5	467.8	"
1946-47							9.6	3.2	3.2	"	8.1	138.5	478.9	"
1947-48							5.9	0.0	0.3	"	2.9	153.9	491.8	"
1948-49							181.8	178.5	178.8	178.1	203.5	331.9	595.8	"
1949-50							5.9	0.0	0.3	0.0	2.9	157.7	444.6	"
1950-51							"	"	"	"	"	121.9	460.1	"
1951-52							7.3	6.4	12.7	13.3	39.4	215.3	509.7	"
1952-53							10.2	8.8	13.0	15.2	38.2	192.1	474.9	"
1953-54							5.9	0.0	0.3	0.0	2.9	105.5	444.6	"
1954-55							23.4	15.1	13.7	"	27.3	185.2	507.4	"
1955-56							5.9	0.0	0.3	"	2.9	105.5	460.9	"
1956-57							"	"	"	"	"	152.5	527.5	"
1957-58							8.5	2.3	2.3	"	6.6	117.5	481.7	"
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	122	3071	2453
VARIABLE REFILL CURVES					80 MAF		100	100	100	100	100	100	800	1900
(BY VOLUME RUNOFF AT THE DALLES)					95 MAF		100	100	100	100	100	100	500	1500
					110 MAF		100	100	100	100	100	100	400	1200
VARIABLE REFILL CURVE LOWER LIMITS (KSFD)					80 MAF		365.3	40.6	62.1	81.9	114.8	323.1	598.4	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)							118.4	18.7	0.2	0.0				

Note: These PDRs do not reflect the update to the VRCLL to avoid crossovers. VRCLL adjustment was made after the Refill Study.

TABLE 7
(English Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2009 - 10 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	3529.2	3529.2	3929.2	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)
2009 - 10 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)
2009 - 10 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)
2009 - 10 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7811.6	7407.1	6971.7	6228.6	5110.5	3560.5	3193.7	3296.1	3412.7	3660.4	5391.6	6895.3	7814.6
1929-30	"	"	"	"	"	"	2886.1	2543.4	2511.6	2562.1	2996.3	5069.0	6684.9	"
1930-31	"	"	"	"	"	"	3389.2	2906.7	2922.6	2947.0	3230.7	4885.0	6705.2	"
1931-32	"	"	"	"	"	"	1224.5	750.6	647.3	634.6	762.3	2573.7	5950.1	"
1932-33	"	"	"	"	"	"	1074.5	636.1	547.7	531.0	616.4	2430.2	5697.0	"
1933-34	"	"	"	"	"	"	776.1	185.8	17.6	0.0	37.7	2743.6	6401.4	"
1934-35	"	"	"	"	"	"	1919.1	1708.5	1762.2	1818.3	2090.1	3948.5	6323.2	"
1935-36	"	"	"	"	"	"	1827.5	1513.3	1403.3	1375.8	1664.2	3993.1	6663.5	"
1936-37	"	"	"	"	"	"	3560.5	3193.7	3295.2	3399.5	3652.7	5346.6	6984.5	"
1937-38	"	"	"	"	"	"	1477.4	1178.5	1091.4	1146.6	1487.3	3421.6	6201.8	"
1938-39	"	"	"	"	"	"	3014.5	2633.3	2536.6	2553.7	2914.0	4887.2	7045.4	"
1939-40	"	"	"	"	"	"	2554.6	2173.2	2168.7	2302.3	2730.2	4667.9	6760.8	"
1940-41	"	"	"	"	"	"	3540.7	3052.1	3104.8	3221.9	3600.3	5337.6	7116.1	"
1941-42	"	"	"	"	"	"	3316.6	3030.5	2850.0	2934.6	3132.9	4874.7	6849.4	"
1942-43	"	"	"	"	"	"	3116.8	2795.8	2785.5	2754.5	3145.0	4241.5	5972.1	"
1943-44	"	"	"	"	"	"	3560.5	3193.7	3296.1	3412.7	3660.4	5399.5	7146.5	"
1944-45	"	"	"	"	"	"	3475.2	"	3292.4	3399.2	3628.0	5176.0	7128.6	"
1945-46	"	"	"	"	"	"	857.0	369.6	261.7	234.4	333.2	2181.5	5945.6	"
1946-47	"	"	"	"	"	"	1044.5	610.8	534.9	559.3	928.0	3061.2	6161.5	"
1947-48	"	"	"	"	"	"	919.7	465.3	371.2	339.4	426.8	2401.9	5951.0	"
1948-49	"	"	"	"	"	"	3296.9	3097.4	2895.5	2975.5	3169.7	4979.1	7146.5	"
1949-50	"	"	"	"	"	"	1275.1	781.4	663.5	636.5	728.5	2548.7	5524.4	"
1950-51	"	"	"	"	"	"	1266.4	826.0	782.3	766.3	1119.8	2988.5	6235.9	"
1951-52	"	"	"	"	"	"	1673.2	1184.4	1104.2	1074.0	1359.7	3425.3	6277.7	"
1952-53	"	"	"	"	"	"	2335.4	2051.0	1975.6	1970.3	2197.2	3853.9	6359.9	"
1953-54	"	"	"	"	"	"	830.2	371.5	294.4	280.6	371.7	2087.4	5021.1	"
1954-55	"	"	"	"	"	"	1934.3	1704.6	1672.5	1655.5	1974.2	3716.1	6217.8	"
1955-56	"	"	"	"	"	"	1138.4	678.1	572.0	547.6	643.6	2587.9	6011.1	"
1956-57	"	"	"	"	"	"	1307.0	839.4	748.0	735.7	832.3	2577.0	6539.7	"
1957-58	"	"	"	"	"	"	1192.5	737.8	655.1	649.9	765.0	2581.6	6188.7	"

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

	2002-03	2003-04 2004-05 1/	2005-06	2006-07 through 2008-09 2/	2009-10
MICA TARGET OPERATION					
(ksfd[xxxx.x] or cfs [xxxxx])					
AUG 15	3486.2	3499.2	3499.1	3454.2	3454.2
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	3524.1	FULL	FULL
OCT	3396.2	3374.1	3344.1	3428.4	3428.4
NOV	20000	20000	23000	20000	22000
DEC	22000	23000	25000	25000	25000
JAN	24000	25000	26000	24000	23000
FEB	21000	21000	22000	21000	20000
MAR	18000	19000	20000	18000	17000
APR 15	281.3	204.1	16000	18000	18000
APR 30	15000	15000	13000	12000	11000
MAY	10000	10000	10000	10000	10000
JUN	10000	10000	10000	10000	10000
JUL	3456.2	3449.2	3449.1	3379.2	3436.2
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (ksfd)					
1928 AUG 31	7811.1	7808.9	7678.3	7786.1	7811.6
1928 DEC	5811.1	5213.8	4938.9	5133.8	5110.5
1929 APR15	1452.6	1598.5	927.1	839.3	671.5
1929 JUL	7426.8	7280.7	7222	7147.7	7168.9
COMPOSITE CANADIAN TREATY STORAGE CONTENT (ksfd)					
60-Yr Average					
AUG 31	7414.6	7415.0	7238.3	7360.7	7455.5
DEC	5226.9	4759.5	4437.3	4634.9	4640.3
APR15	1173.1	1097.7	1085.8	1178.5	877.8
JUL	7339.0	7262.0	7215.5	7193.7	7277.6
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-0.3	-1.2	-0.1	-0.2	-0.3
U.S. Dependable Peaking Capacity	-18.0	16.0	-51.0	-21.0	-2.7
U.S. Average Annual Usable Secondary Energy	3.7	12.9	10.5	0.3	13.8
BCH Firm Energy	30.3	43.1	97.7	90.3	50.2
BCH Dependable Peaking Capacity	26.0	8.0	2.0	11.0	44.9
BCH Average Annual Usable Secondary Energy	-17.3	-24.3	-55.7	-29.3	-28.2
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	10368	10439	11097	11137	11138
AUG 31	10355	10435	11125	11165	11166
SEP	9911	10101	10809	10849	10850
OCT	10051	10186	9742	9782	9783
NOV	11716	11807	10817	11157	11157
DEC	13160	13377	12853	13192	13193
JAN	13707	13122	12735	13075	13076
FEB	12694	12240	11561	11901	11901
MAR	11858	11175	11275	11315	11316
APR 15	11460	10541	10550	10589	10590
APR 30	13101	13065	14061	12822	12823
MAY	14357	13752	14729	13491	13491
JUN	13324	13114	14039	14079	14079
JUL	10457	12079	12383	12723	12724
ANNUAL AVERAGE	11986	11933	12034	12037	12038

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

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

TABLE 1M
(Metric Units)
MICA PROJECT OPERATING CRITERIA
2009-10 ASSURED OPERATING PLAN

		Target Operation		Target Operation Limits		
Month	End of Previous Month **Arrow** Storage Content (hm^3)	Month Average Outflow (m^3/s)	End-of-Month Treaty Storage Content 1/ (hm^3)	Minimum Treaty Storage Content 2/ (hm^3)	Maximum Outflow 1/ (m^3/s)	Minimum Outflow (m^3/s)
August 1-15	8,563.1 - FULL	-	8,451.0	-	962.77	424.75
	6,165.4 - 8,563.1	707.92	-	0.0	-	424.75
	0.0 - 6,165.4	906.14	-	0.0	-	424.75
August 16-31	6,116.5 - FULL	-	8,634.5	-	962.77	424.75
	4,893.2 - 6,116.5	707.92	-	0.0	-	424.75
	0.0 - 4,893.2	906.14	-	0.0	-	424.75
September	8,734.4 - FULL	-	8,634.5	-	962.77	283.17
	7,853.6 - 8,734.4	622.97	-	0.0	-	283.17
	5,627.2 - 7,853.6	764.55	-	0.0	-	283.17
	0.0 - 5,627.2	906.14	-	0.0	-	283.17
October	8,734.4 - FULL	-	8,387.9	-	962.77	283.17
	7,780.2 - 8,734.4	538.02	-	0.0	-	283.17
	1,223.3 - 7,780.2	622.97	-	0.0	-	283.17
	0.0 - 1,223.3	906.14	-	0.0	-	283.17
November	7,706.8 - FULL	622.97	-	0.0	-	283.17
	7,584.5 - 7,706.8	538.02	-	0.0	-	283.17
	1,003.1 - 7,584.5	707.92	-	0.0	-	283.17
	0.0 - 1,003.1	906.14	-	0.0	-	283.17
December	6,997.3 - FULL	707.92	-	499.4	-	283.17
	3,718.8 - 6,997.3	764.55	-	499.4	-	283.17
	1,468.0 - 3,718.8	622.97	-	499.4	-	283.17
	0.0 - 1,468.0	906.14	-	499.4	-	283.17
January	6,605.8 - FULL	651.29	-	377.0	-	339.80
	6,116.5 - 6,605.8	736.24	-	377.0	-	339.80
	5,260.2 - 6,116.5	792.87	-	377.0	-	339.80
	0.0 - 5,260.2	849.50	-	377.0	-	339.80
February	3,669.9 - FULL	566.34	-	0.0	-	339.80
	3,009.3 - 3,669.9	594.65	-	0.0	-	339.80
	2,813.6 - 3,009.3	651.29	-	0.0	-	339.80
	0.0 - 2,813.6	736.24	-	0.0	-	339.80
March	2,691.3 - FULL	481.39	-	0.0	-	339.80
	782.9 - 2,691	538.02	-	0.0	-	339.80
	97.9 - 783	679.60	-	0.0	-	339.80
	0.0 - 98	594.65	-	0.0	-	339.80
April 1-15	2,422.1 - FULL	509.70	-	0.0	-	339.80
	2,104.1 - 2,422.1	538.02	-	0.0	-	339.80
	195.7 - 2,104.1	396.44	-	0.0	-	339.80
	0.0 - 195.7	538.02	-	0.0	-	339.80
April 16-30	2,079.6 - FULL	311.49	-	0.0	-	283.17
	1,223.3 - 2,079.6	368.12	-	0.0	-	283.17
	48.9 - 1,223.3	283.17	-	0.0	-	283.17
	0.0 - 48.9	481.39	-	0.0	-	283.17
May	1,590.3 - FULL	283.17	-	0.0	-	226.53
	391.5 - 1,223.3	283.17	-	0.0	-	226.53
	0.0 - 391.5	226.53	-	0.0	-	226.53
June	5,382.5 - FULL	283.17	-	0.0	-	226.53
	2,691.3 - 5,382.5	226.53	-	0.0	-	226.53
	1,516.9 - 2,691.3	453.07	-	0.0	-	226.53
	0.0 - 1,516.9	283.17	-	0.0	-	226.53
July	6,238.8 - FULL	-	8,407.0	-	962.77	283.17
	3,718.8 - 6,238.8	538.02	-	0.0	-	283.17
	0.0 - 3,718.8	877.82	-	0.0	-	283.17

1/ If the Mica target end-of-month storage content is less than 8634.5 hm^3, then a maximum outflow of 962.77 m^3/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 1.1aM
(Metric Units)
ARROW PROJECT OPERATING CRITERIA
2009-10 ASSURED OPERATING PLAN

Period	Volume Runoff Period	The Dalles Volume Runoff (km^3)	Maximum Storage Limit 1/ 2/ (hm^3)	Maximum Outflow Limit 3/ (m^3/s)
January			URC	2,010
February	1 Feb - 31 Jul	≤ 86	URC	1,699
		>86 to <99	URC to 4404	
		≥ 99	4404	
March	1 Mar - 31 Jul	≤ 80	URC	
		>80 to <93	URC to 2202	
		≥ 93	2202	
April 15	1 Apr - 31 Jul	≤ 75	URC	
		>75 to <86	URC to 2202	
		≥ 86	2202	
April 30	1 Apr - 31 Jul	≤ 75	URC	
		>75 to <86	URC to 2447	
		≥ 86	2447	
May	1 May - 31 Jul	≤ 84	URC	
		>84 to <86	URC to 4404	
		≥ 86	4404	
June	1 Jun - 31 Jul	≤ 41	URC	
		>41 to <43	URC to 8074	
		≥ 43	8074	

Notes:

1/ If the Maximum Storage Limit is computed to be above the URC, then the URC will apply.

2/ Interpolate when there are two values. For example, if the February-July volume runoff is between 86 km^3 and 99 km^3, then the Maximum Storage Limit is interpolated between February's URC and 4404 hm^3.

3/ The Maximum Average Monthly Outflow Limit takes precedence over the Maximum Storage Limit. However, the Maximum Outflow Limit may be exceeded to avoid storage above the URC.

TABLE 1.1bM
(Metric Units)
ARROW PROJECT OPERATING CRITERIA
FOR 2009-10 ASSURED OPERATING PLAN

Maximum Average Monthly Flow Limits (m^3/s)

Period	JAN	FEB
Flow Limit	2,010	1,699

End-of-Period Maximum Storage Limits (hm^3)

Year	FEB	MAR	APR15	APR30	MAY	JUN
1928-29	URC	URC	URC	URC	URC	8455.6
1929-30	URC	URC	URC	URC	URC	URC
1930-31	URC	URC	URC	URC	URC	URC
1931-32	4403.8	2201.9	2201.9	2446.6	4403.8	8073.7
1932-33	4403.8	2201.9	2201.9	2446.6	4403.8	URC
1933-34	4403.8	2201.9	2201.9	2446.6	URC	URC
1934-35	4403.8	2201.9	2201.9	2446.6	URC	URC
1935-36	4403.8	2201.9	2201.9	2446.6	URC	URC
1936-37	URC	URC	URC	URC	URC	8373.2
1937-38	4403.8	2201.9	2201.9	2446.6	4403.8	URC
1938-39	4739.8	2280.5	2883.3	3075.3	URC	URC
1939-40	4872.8	2959.9	4787.7	4878.2	URC	URC
1940-41	URC	URC	URC	URC	URC	URC
1941-42	4403.8	2201.9	2201.9	2446.6	URC	8073.7
1942-43	4403.8	2201.9	2201.9	2446.6	4403.8	URC
1943-44	URC	URC	URC	URC	URC	URC
1944-45	4535.5	2368.8	2512.4	2731.8	URC	8073.7
1945-46	4403.8	2201.9	2201.9	2446.6	4403.8	8073.7
1946-47	4403.8	2201.9	2201.9	2446.6	4403.8	8073.7
1947-48	4403.8	2201.9	2201.9	2446.6	4403.8	8073.7
1948-49	4403.8	2201.9	2201.9	2446.6	6752.3	URC
1949-50	4403.8	2201.9	2201.9	2446.6	4403.8	URC
1950-51	4403.8	2201.9	2201.9	2446.6	4403.8	8073.7
1951-52	4403.8	2201.9	2201.9	2446.6	4403.8	URC
1952-53	4403.8	2201.9	2201.9	2446.6	4403.8	URC
1953-54	4403.8	2201.9	2201.9	2446.6	4403.8	URC
1954-55	4403.8	2201.9	2201.9	2446.6	4403.8	8073.7
1955-56	4403.8	2201.9	2201.9	2446.6	4403.8	URC
1956-57	4403.8	2201.9	2201.9	2446.6	4403.8	8073.7
1957-58	4403.8	2201.9	2201.9	2446.6	4403.8	8073.7

TABLE 1.1cM
(Metric Units)
APOC IMPLEMENTATION: DISTRIBUTION FACTORS FOR THE DALLES
2009-10 ASSURED OPERATING PLAN

Forecast Date	Forecast Period	The Dalles Distribution Factors 1/ Jan-Jul	Feb-Jul	Mar-Jul	Apr-Jul	May-Jul	Jun-Jul
01-Jan	1 Jan - 31 Jul	1.0000	0.9392	0.8589	0.7735	0.7174	0.4393
01-Feb	1 Feb - 31 Jul		1.0000	0.9145	0.8235	0.7638	0.4677
01-Mar	1 Mar - 31 Jul			1.0000	0.9005	0.8352	0.5114
01-Apr	1 Apr - 31 Jul				1.0000	0.9275	0.5679
01-May	1 May - 31 Jul					1.0000	0.6123
01-Jun	1 Jun - 31 Jul						1.0000

Notes:

1/ Unless otherwise agreed, the DOP10 will apply these distribution factors to the monthly volume forecast at The Dalles for computing the Month-July runoff volumes required by the APOC.

2. These distribution factors are calculated from the median 71 year Jan-Jul, Feb-Jul, etc., volumes.

For Example, in the month of May:

1 May Forecast Forecast Volume = 80.2 km^3 (May-Jul)	From Table 1.1cM The Dalles Distribution Factor	Month-Jul Volume Runoff (km^3)	Look up Table 1.1aM The Dalles Volume Runoff (km^3)	Maximum Storage Limit (hm^3)
May	1.0000	80.2	$\leq$ 83.9	URC
June	0.6123	49.1	$\geq$ 43.2	8074

TABLE 3M
(Metric Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2009 - 10 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	8634.5	8631.8	8596.9	8331.4	7285.7	5551.3	3607.5	1743.0	1117.4	347.9	338.6	940.0	4957.5	7450.1
1929-30	8294.5	8600.8	8226.0	6072.7	4979.1	3770.0	1428.6	608.5	3.7	4.4	388.5	1296.7	2924.4	6317.4
1930-31	7200.3	8001.6	8007.5	6102.8	5110.0	3239.5	1868.0	513.1	1.0	0.0	0.0	618.3	2385.2	5223.5
1931-32	4979.3	4564.6	2932.7	2571.6	1619.4	135.8	11.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	8757.8	8753.2	7840.1	7048.9	6494.7	5819.5	3332.3	2028.7	1214.0	1064.0	1017.8	3787.1	7559.3	8561.4
1929-30	8641.4	8704.0	7292.6	6914.1	4910.3	3567.6	1172.2	512.3	0.0	2.0	579.8	3239.5	6435.3	8468.7
1930-31	8555.8	8438.6	7199.4	6767.5	4672.5	3517.7	1162.4	273.5	0.0	0.0	0.0	2478.4	4580.0	4295.3
1931-32	4343.2	4606.0	4264.4	2853.7	2492.6	473.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	1726.8	1726.8	1685.2	1676.7	1458.4	1132.5	893.7	464.9	305.6	231.0	258.6	546.1	1218.4	1527.9
1929-30	1644.1	1621.4	1474.3	1449.6	1466.5	1231.6	916.3	416.9	4.6	6.9	79.8	360.4	897.7	1428.3
1930-31	1616.5	1424.7	1495.6	1564.8	1573.2	940.7	460.5	88.1	3.4	0.0	0.0	310.7	225.1	438.4
1931-32	502.8	303.6	299.5	195.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	19119.2	19111.9	18122.2	17057.0	15238.9	12503.3	7833.5	4236.5	2636.9	1642.9	1615.0	5273.2	13735.2	17539.4
1929-30	18580.0	18926.2	16992.9	14436.4	11355.9	8569.2	3517.0	1537.7	8.3	13.2	1048.1	4896.6	10257.4	16214.4
1930-31	17372.6	17864.8	16702.4	14435.2	11355.6	7698.0	3490.8	874.7	4.4	0.0	0.0	3407.4	7190.3	9957.2
1931-32	9825.3	9474.2	7496.6	5620.6	4112.0	609.0	11.7	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
2009 - 10 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	960.5	2386.9	3860.7	4297.7	4457.5	4497.6	4485.1	4457.0	4473.4	4534.5	4689.4	5267.8	7895.4	8634.5
VARIABLE REFILL CURVES (hm^3)														
1928-29							5982.2	5699.4	5603.2	5616.9	5716.0	6805.7	8083.1	8634.5
1929-30							3481.0	3102.0	2982.7	3039.9	3421.8	5322.8	7388.7	"
1930-31							4111.8	3754.8	3624.1	3628.8	3848.7	5369.1	7571.5	"
1931-32							1987.6	1648.3	1533.8	1540.1	1826.1	3618.5	6692.2	"
1932-33							1620.6	1368.1	1296.0	1297.2	1486.1	3232.9	6214.4	"
1933-34							29.1	0.0	0.0	0.0	0.0	2584.3	6814.0	"
1934-35							3325.7	3027.2	2984.9	3035.0	3205.8	4782.6	7010.5	"
1935-36							2805.8	2508.5	2438.5	2438.8	2670.5	4663.5	7652.5	"
1936-37							5949.6	5616.4	5484.1	5470.8	5687.9	6835.6	8160.4	"
1937-38							2606.4	2308.1	2193.9	2211.0	2437.8	4103.7	6880.1	"
1938-39							3610.4	3420.8	3324.0	3391.7	3662.8	5402.1	8127.6	"
1939-40							3077.1	2797.7	2743.4	2796.2	3112.1	4905.7	7542.1	"
1940-41							4564.6	4258.1	4174.9	4227.0	4658.8	6294.9	8116.6	"
1941-42							4552.4	4255.4	4152.4	4147.5	4332.7	5807.7	7816.2	"
1942-43							4062.8	3710.0	3599.7	3594.3	3966.2	5536.7	7403.7	"
1943-44							6208.0	5836.4	5737.5	5746.6	5913.4	7103.7	8501.9	"
1944-45							5992.7	5711.6	5646.3	5681.5	5801.9	6885.7	8284.9	"
1945-46							1088.5	716.1	597.5	573.5	796.6	2714.5	6586.2	"
1946-47							1547.2	1306.2	1258.0	1287.2	1571.9	3532.9	6857.8	"
1947-48							1241.9	950.3	865.4	830.4	1025.6	2852.0	6475.9	"
1948-49							5885.8	5532.0	5380.8	5374.7	5563.1	6711.5	8634.5	"
1949-50							2111.4	1723.6	1580.5	1557.3	1763.8	3393.2	6014.5	"
1950-51							2090.1	1818.8	1754.0	1774.3	2052.0	3684.6	6898.7	"
1951-52							3085.4	2709.6	2582.6	2545.7	2744.6	4407.3	7259.3	"
1952-53							3980.9	3648.9	3545.1	3539.5	3684.6	4994.5	7298.5	"
1953-54							1022.9	720.8	677.5	686.5	890.8	2647.0	5946.2	"
1954-55							3724.2	3461.2	3397.8	3423.0	3633.7	5069.4	6909.9	"
1955-56							1777.0	1470.9	1356.6	1339.8	1556.0	3435.0	6689.7	"
1956-57							2189.5	1865.5	1787.2	1800.0	2017.7	3645.7	7498.6	"
1957-58							1909.3	1617.0	1554.6	1580.5	1837.4	3519.9	6991.2	"
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	84.95	578.77	689.12	1323.75
VARIABLE REFILL CURVES					98.68 km^3		84.95	84.95	84.95	84.95	84.95	84.95	707.92	1047.72
(BY VOLUME RUNOFF AT THE DALLES)					117.18 km^3		84.95	84.95	84.95	84.95	84.95	84.95	679.60	1019.41
					135.69 km^3		84.95	84.95	84.95	84.95	84.95	84.95	509.70	792.87
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 (hm^3)							890.6	266.4	0.2	0.0				

Note: These PDRs do not reflect the update to the VRCLL to avoid crossovers. VRCLL adjustment was made after the Refill Study.

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
2009 - 10 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	0.0	0.0	0.0	0.0	0.0	1588.8	2765.1	2845.2	3044.8	3242.2	3655.2	6949.1	8231.6	8757.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							5792.3	5297.6	4962.4	4854.1	5147.2	7648.6	7617.0	8757.8
1929-30							2686.4	2609.1	2616.1	2655.8	3298.0	6140.5	7608.9	"
1930-31							3286.5	3117.7	2980.2	3008.6	3444.6	5783.0	7475.8	"
1931-32							9.8	0.1	42.8	12.5	20.1	2304.2	6711.8	"
1932-33							5.7	0.0	42.2	2.1	13.0	2448.3	6631.1	"
1933-34							4.9	0.0	42.1	0.0	11.5	3563.2	7524.8	"
1934-35							1079.9	1096.8	1264.4	1350.0	1784.6	4419.8	7265.7	"
1935-36							1352.0	1132.0	920.4	867.6	1260.5	4519.1	7316.6	"
1936-37							6546.6	5943.5	5582.9	5405.0	5751 2	8077.9	7855.1	"
1937-38							588.9	529.4	471.7	578.1	1110.8	3774.9	7072.4	"
1938-39							3060.9	2845.6	2701.5	2666.3	3241.0	5944.7	7984.2	"
1939-40							2431.7	2361.9	2382.5	2624.0	3286.5	5766.9	7641.2	"
1940-41							4463.3	4286.0	4193.2	4473.9	5248.7	8350.5	8401.9	"
1941-42							4095.6	3932.7	4393.6	4348.6	4979.6	6825.5	7607.0	"
1942-43							3273.1	3066.6	2921.5	2845.2	3333.5	6336.9	8404.3	"
1943-44							7796.1	7325.4	7022.0	6852.4	7248.3	8757.8	8757.8	"
1944-45							6133.9	5773.0	5530.8	5492.1	5827.8	8026.8	8187.8	"
1945-46							4.9	0.0	42.1	0.0	11.5	2364.6	6815.7	"
1946-47							353.5	90.0	42.8	81.2	678.7	3617.8	7045.2	"
1947-48							4.9	0.0	42.1	0.0	11.5	2648.0	6880.6	"
1948-49							3136.3	2684.4	3337.7	3319.3	4024.4	6102.1	8484.6	"
1949-50							4.9	0.0	42.1	0.0	11.5	2456.6	6615.1	"
1950-51							194.7	156.3	159.3	100.6	680.6	3328.8	7232.4	"
1951-52							274.0	138.2	87.8	49.4	485.7	3446.3	7162.4	"
1952-53							1443.2	1323.4	1256.6	1243.9	1680.3	4441.1	7099.8	"
1953-54							4.9	0.0	42.1	0.0	11.5	2201.9	6637.6	"
1954-55							647.1	663.5	660.6	627.3	1161.4	3848.7	7106.7	"
1955-56							4.9	0.0	42.1	0.0	11.5	2638.4	6889.4	"
1956-57							"	"	"	"	"	2286.1	7210.9	"
1957-58							8.6	0.1	42.6	9.5	18.1	2508.7	6971.6	"
DISTRIBUTION FACTORS							0.9710	0.9747	0.9691	0.9741	0.9530	0.7483	0.4631	N/A
FORECAST ERRORS (hm^3)							3016.9	2415.5	2019.2	1749.6	1749.6	1226.7	1226.7	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	510.16	1731.83	2042.15
VARIABLE REFILL CURVES					98.68 km^3		141.58	141.58	141.58	141.58	141.58	141.58	1500.79	1529.11
(BY VOLUME RUNOFF AT THE DALLES)					117.18 km^3		141.58	141.58	141.58	141.58	141.58	141.58	1444.16	1444.16
					135.69 km^3		141.58	141.58	141.58	141.58	141.58	141.58	764.55	1245.94
VARIABLE REFILL 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
(By VOLUME 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
OPERATING RULE CURVE LOWER LIMITS (hm^3)							718.6	142.4	0.0	0.0				

Note: These PDRs do not reflect the update to the VRCLL to avoid crossovers. VRCLL adjustment was made after the Refill Study.

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
2009 - 10 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	9.1	156.8	319.0	394.1	437.0	464.4	489.1	511.6	546.1	572.7	610.9	993.6	1357.6	1726.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							893.7	705.8	698.5	694.8	735.7	974.2	1464.0	1726.8
1929-30							"	701.0	692.9	688.7	748.2	1024.4	"	"
1930-31							"	568.3	569.1	576.9	632.9	900.8	"	"
1931-32							22.8	7.3	7.2	0.0	18.8	374.1	1153.6	"
1932-33							15.9	1.2	1.8	"	9.1	264.5	1092.8	"
1933-34							14.4	0.0	0.7	"	80.7	564.9	1322.9	"
1934-35							223.4	56.1	62.2	63.6	123.3	555.2	1313.8	"
1935-36							313.4	61.9	74.4	59.7	140.7	586.9	1333.9	"
1936-37							893.7	546.6	543.9	540.5	592.1	864.1	1464.0	"
1937-38							19.6	4.5	4.7	16.1	90.3	492.7	1220.9	"
1938-39							762.6	176.6	180.6	189.9	267.9	744.5	1434.7	"
1939-40							772.1	157.3	180.1	212.6	297.0	747.9	1436.9	"
1940-41							893.7	364.1	376.5	413.5	525.0	874.7	1464.0	"
1941-42							297.0	313.9	326.1	335.7	407.8	742.8	1334.6	"
1942-43							286.0	285.0	293.8	299.7	394.9	755.8	1288.1	"
1943-44							893.7	732.3	735.9	737.2	795.4	1040.8	1492.4	"
1944-45							685.0	530.4	537.0	539.7	584.5	852.6	1417.3	"
1945-46							14.4	0.0	0.7	0.0	7.1	258.1	1144.5	"
1946-47							23.6	7.9	7.8	"	19.9	338.9	1171.7	"
1947-48							14.4	0.0	0.7	"	7.1	376.5	1203.2	"
1948-49							444.8	436.7	437.5	435.7	497.9	812.0	1457.7	"
1949-50							14.4	0.0	0.7	0.0	7.1	385.8	1087.8	"
1950-51							"	"	"	"	"	298.2	1125.7	"
1951-52							17.9	15.7	31.1	32.5	96.4	526.8	1247.0	"
1952-53							25.0	21.5	31.8	37.2	93.5	470.0	1161.9	"
1953-54							14.4	0.0	0.7	0.0	7.1	258.1	1087.8	"
1954-55							57.3	37.0	33.5	"	66.8	453.2	1241.5	"
1955-56							14.4	0.0	0.7	"	7.1	258.1	1127.6	"
1956-57							"	"	"	"	"	373.1	1290.6	"
1957-58							20.9	5.6	5.6	"	16.1	287.5	1178.5	"
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	3.45	86.96	69.46
VARIABLE REFILL CURVES					98.68 km^3		2.83	2.83	2.83	2.83	2.83	2.83	22.65	53.80
(BY VOLUME RUNOFF AT THE DALLES)					117.18 km^3		2.83	2.83	2.83	2.83	2.83	2.83	14.16	42.48
					135.69 km^3		2.83	2.83	2.83	2.83	2.83	2.83	11.33	33.98
VARIABLE REFILL CURVE LOWER LIMITS (hm^3)					98.68 km^3		893.7	99.3	151.9	200.4	280.9	790.5	1464.0	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)							289.7	45.8	0.5	0.0				

Note: These PDRs do not reflect the update to the VRCLL to avoid crossovers. VRCLL adjustment was made after the Refill Study.

TABLE 7M
(Metric Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2009 - 10 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8634.5	8634.5	9613.2	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)
2009 - 10 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)
2009 - 10 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)
2009 - 10 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.2	19111.9	18122.2	17057.0	15238.9	12503.3	8711.1	7813.7	8064.2	8349.5	8955.5	13191.1	16870.0	19119.2
1929-30	"	"	"	"	"	"	7061.1	6222.7	6144.9	6268.4	7330.7	12401.8	16355.3	"
1930-31	"	"	"	"	"	"	8292.0	7111.5	7150.4	7210.1	7904.2	11951.6	16404.9	"
1931-32	"	"	"	"	"	"	2995.9	1836.4	1583.7	1552.6	1865.0	6296.8	14557.5	"
1932-33	"	"	"	"	"	"	2628.9	1556.3	1339.9	1299.2	1508.1	5945.7	13938.2	"
1933-34	"	"	"	"	"	"	1898.8	454.6	43.1	0.0	92.2	6712.5	15661.7	"
1934-35	"	"	"	"	"	"	4695.3	4180.0	4311.5	4448.7	5113.6	9660.4	15470.4	"
1935-36	"	"	"	"	"	"	4471.2	3702.4	3433.3	3366.0	4071.6	9769.5	16302.9	"
1936-37	"	"	"	"	"	"	8711.1	7813.7	8062.0	8317.2	8936.7	13081.0	17088.3	"
1937-38	"	"	"	"	"	"	3614.6	2883.3	2670.3	2805.3	3638.8	8371.3	15173.3	"
1938-39	"	"	"	"	"	"	7375.3	6442.6	6206.0	6247.9	7129.4	11957.0	17237.3	"
1939-40	"	"	"	"	"	"	6250.1	5317.0	5305.9	5632.8	6679.7	11420.5	16541.0	"
1940-41	"	"	"	"	"	"	8662.7	7467.3	7596.2	7882.7	8808.5	13059.0	17410.3	"
1941-42	"	"	"	"	"	"	8114.4	7414.4	6972.8	7179.8	7665.0	11926.4	16757.7	"
1942-43	"	"	"	"	"	"	7625.6	6840.2	6815.0	6739.2	7694.6	10377.3	14611.3	"
1943-44	"	"	"	"	"	"	8711.1	7813.7	8064.2	8349.5	8955.5	13210.4	17484.6	"
1944-45	"	"	"	"	"	"	8502.4	"	8055.2	8316.5	8876.3	12663.6	17440.8	"
1945-46	"	"	"	"	"	"	2096.7	904.3	640.3	573.5	815.2	5337.3	14546.5	"
1946-47	"	"	"	"	"	"	2555.5	1494.4	1308.7	1368.4	2270.5	7489.5	15074.7	"
1947-48	"	"	"	"	"	"	2250.1	1138.4	908.2	830.4	1044.2	5876.5	14559.7	"
1948-49	"	"	"	"	"	"	8066.2	7578.1	7084.1	7279.9	7755.0	12181.9	17484.6	"
1949-50	"	"	"	"	"	"	3119.7	1911.8	1623.3	1557.3	1782.3	6235.6	13516.0	"
1950-51	"	"	"	"	"	"	3098.4	2020.9	1914.0	1874.8	2739.7	7311.7	15256.8	"
1951-52	"	"	"	"	"	"	4093.7	2897.8	2701.5	2627.6	3326.6	8380.3	15359.0	"
1952-53	"	"	"	"	"	"	5713.8	5018.0	4833.5	4820.5	5375.7	9429.0	15560.1	"
1953-54	"	"	"	"	"	"	2031.2	908.9	720.3	686.5	909.4	5107.0	12284.6	"
1954-55	"	"	"	"	"	"	4732.5	4170.5	4091.9	4050.3	4830.1	9091.8	15212.5	"
1955-56	"	"	"	"	"	"	2785.2	1659.0	1399.5	1339.8	1574.6	6331.6	14706.8	"
1956-57	"	"	"	"	"	"	3197.7	2053.7	1830.1	1800.0	2036.3	6304.9	16000.0	"
1957-58	"	"	"	"	"	"	2917.6	1805.1	1602.8	1590.0	1871.6	6316.1	15141.3	"

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

	2002-03	2003-04 2004-05 1/	2005-06	2006-07 through 2008-09 2/	2009-10
MICA TARGET OPERATION					
(hm³ [xxxx.x] or m³/s [xxxx.xx])					
AUG 15	8529.3	8561.1	8560.9	8451.0	8451.0
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	8622.1	FULL	FULL
OCT	8309.1	8255.1	8181.7	8387.9	8387.9
NOV	566.34	566.34	651.29	566.34	622.97
DEC	622.97	651.29	707.92	707.92	707.92
JAN	679.60	707.92	736.24	679.60	651.29
FEB	594.65	594.65	622.97	594.65	566.34
MAR	509.70	538.02	566.34	509.70	481.39
APR 15	688.2	499.4	453.07	509.70	509.70
APR 30	424.75	424.75	368.12	339.80	311.49
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	8438.8	8438.6	8267.6	8407.0
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (hm³)					
1928 AUG 31	19110.6	19105.3	18785.7	19049.5	19111.9
1928 DEC	14217.4	12756.1	12083.5	12560.4	12503.3
1929 APR15	3553.9	3910.9	2268.2	2053.4	1642.9
1929 JUL	18170.4	17813.0	17669.3	17487.6	17539.4
COMPOSITE CANADIAN TREATY STORAGE CONTENT (hm³)					
60-Yr Average					
AUG 31	18140.6	18141.5	17709.2	18008.7	18240.6
DEC	12788.1	11644.6	10856.3	11339.7	11353.0
APR15	2870.1	2685.6	2656.5	2883.3	2147.6
JUL	17955.6	17767.2	17653.4	17600.1	17805.4
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-0.3	-1.2	-0.1	-0.2	-0.3
U.S. Dependable Peaking Capacity	-18.0	16.0	-51.0	-21.0	-2.7
U.S. Average Annual Usable Secondary Energy	3.7	12.9	10.5	0.3	13.8
BCH Firm Energy	30.3	43.1	97.7	90.3	50.2
BCH Dependable Peaking Capacity	26.0	8.0	2.0	11.0	44.9
BCH Average Annual Usable Secondary Energy	-17.3	-24.3	-55.7	-29.3	-28.2
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	10368	10439	11097	11137	11138
AUG 31	10355	10435	11125	11165	11166
SEP	9911	10101	10809	10849	10850
OCT	10051	10186	9742	9782	9783
NOV	11716	11807	10817	11157	11157
DEC	13160	13377	12853	13192	13193
JAN	13707	13122	12735	13075	13076
FEB	12694	12240	11561	11901	11901
MAR	11858	11175	11275	11315	11316
APR 15	11460	10541	10550	10589	10590
APR 30	13101	13065	14061	12822	12823
MAY	14357	13752	14729	13491	13491
JUN	13324	13114	14039	14079	14079
JUL	10457	12079	12383	12723	12724
ANNUAL AVERAGE	11933	12034	12034	12037	12038

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

Appendix A
Project Operating Procedures for the 2009-10 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months: Apr=Apr.1-30, Apr.15=Apr.1-Apr.15, Apr30=Apr.15-Apr.30; Aug=Aug.1-31, Aug.15=Aug.1-15, Aug.31=Aug.16-31.

Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Canadian Treaty Projects					
Mica (1890)	Minimum Flow	3000 cfs	85.0 m^3/s		In place in AOP79, AOP80, AOP84.
Arrow (1831)	Minimum Flow	5000 cfs	141.6 m^3/s		In place in AOP79, AOP80, AOP84.
	Draft Limit	1.0 ft/day	0.30 m/day		
Duncan (1681)	Minimum Flow	100 cfs	2.8 m^3/s		In place in AOP79, AOP80, AOP84.
	Maximum Flow	10000 cfs	283.2 m^3/s		
	Draft Limit	1.0 ft/day	0.30 m/day		
	Other			Operate to meet IJC orders for Corra Linn.	CRTOC agreement on procedures to implement 1938 IJC order.
Base System					
Hungry Horse (1530)	Minimum Flow	400 cfs	11.3 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	1500 cfs	42.5 m^3/s	All periods	In place in AOP80, AOP84.
	Maximum Flow			None	
	Minimum Content	614.7 ksfd	1503.9 hm^3	Jun - Sep	MPC 2-1-92, PNCA submittal similar operation, Jun-Aug 15, in AOP80.
		2893.0 ft	881.79 m		
		426.3 ksfd	1043 hm^3	May	
		2890.0 ft	880.9 m		
		0.0 ksfd	0 hm^3	Empty Apr 15	FERC, AOP80.
		2883.0 ft	878.74 m		
	Maximum Content	58.6 ksfd	143.37 hm^3	March	In place in AOP80, AOP84.
		2884.0 ft	879.04 m	(Included to help meet the Apr 15 FERC requirement.)	
	Other	0.0 ksfd	0 hm^3	Conditions permitted, should be on or about, empty Mar and Apr 15.	FERC, AOP80.
		2883.0 ft	878.74 m		
Thompson Falls (1490)				None Noted	

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Noxon Rapids (1480)	Minimum Content For Step I:	116.3 ksfd	284.54 hm^3	May - Aug 31,	In place in AOP84, similar operation in AOP80.
		2331.0 ft	710.49 m		
		112.3 ksfd	274.75 hm^3	Sep - Jan,	
		2330.0 ft	710.18 m		
		78.7 ksfd	192.55 hm^3	Feb,	
		2321.0 ft	707.44 m		
		26.5 ksfd	64.834 hm^3	Mar,	
		2305.0 ft	702.56 m		
		0.0 ksfd	0 hm^3	Empty Apr 15, Apr 30, and for end of CP.	
		2295.0 ft	699.52 m		
	Minimum & Maximum Content for Steps II & III:	116.3 ksfd	284.54 hm^3	All periods	In place in AOP79, AOP84.
		2331.0 ft	710.49 m		
Cabinet Gorge (1475)				None Noted	
Albeni Falls (1465)	Minimum Flow	4000 cfs	113.3 m^3/s	All periods	In place in AOP80, AOP84.
	Minimum Content	(Dec may fill on restriction, note below)			
		582.4 ksfd	1424.9 hm^3	Jun - Aug 31	In place in AOP80, AOP84.
		2062.5 ft	628.65 m		
		465.7 ksfd	1139.4 hm^3	Sep	
		2060.0 ft	627.89 m		
		190.4 ksfd	465.83 hm^3	Oct	
		2054.0 ft	626.06 m		
		57.6 ksfd	140.92 hm^3	Nov-Apr 15	
		2051.0 ft	625.14 m		
		190.4 ksfd	465.83 hm^3	Apr 30 (empty at end of CP)	
		2054.0 ft	626.06 m		
		279.0 ksfd	682.59 hm^3	May	
		2056.0 ft	626.67 m		
	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	140.9 hm^3	Nov - Mar	
		2051.0 ft	625.14 m		
		458.4 ksfd	1121.5 hm^3	May	
		2059.8 ft	627.8 m		
		582.4 ksfd	1424.9 hm^3	Sep	
		2062.5 ft	628.7 m		
		465.7 ksfd	1139.4 hm^3	Oct	
		2060.0 ft	627.89 m		
	Kokanee Spawning	1.0 ft	0.30 m	Draft limit below Nov. 20th Elevation through Dec. 31st.	In place before AOP80 and supported by minimum contents noted above.
		0.5 ft	0.15 m	If project fills, draft no more than this amount.	
				Dec. 31 - Mar 31, operate between SMIN and URC within above noted draft limits.	
	Other Spill	50 cfs	1.4 m^3/s	All periods	

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Grand Coulee (1280)	Minimum Flow	30000 cfs	849.5 m^3/s	All periods	In place in AOP79, AOP80, AOP84.
	Minimum Content	0.0 ksfd 1208.0 ft	0.0 hm^3 368.20 m	Empty at end of CP.	
	Step I only:	843.9 ksfd 1240.0 ft	2064.7 hm^3 377.95 m	May and June	Retain as a power operation (for pumping).
	Steps II & III only:	857.9 ksfd 1240.0 ft	2098.9 hm^3 378.0 m	May and June	
	Maximum Content				
	Step I only:	2.0 ft 3.0 ft	0.61 m 0.91 m	Operating room Sep - Nov Operating room Dec - Feb	In place in AOP89 Retain as a power operation.
	Steps II & III only:	2557.1 ksfd 1288.0 ft	6256.1 hm^3 392.58 m	Aug-Nov	
		2518.3 ksfd 1287.0 ft	6161.2 hm^3 392.28 m	Dec-Feb	
	Draft Limit	1.3 ft/day 1.5 ft/day	0.40 m/day 0.46 m/day	(bank sloughage) (Constraint submitted as 1.5 ft/day interpreted as 1.3 ft/day mo.ave.)	
Chief Joseph (1270)	Other Spill	500 cfs	14.2 m^3/s	All periods	
Wells (1220)	Other Spill	1200 cfs	34.0 m^3/s	All periods	With fish ladder
	Fish Spill			None	
Rocky Reach (1200)	Fish Spill/Bypass			None	
	Other Spill	200 cfs	5.7 m^3/s	Aug 31 - Apr 15 (leakage)	
Rock Island (1170)	Fish Spill/Bypass			None	
Wanapum (1165)	Fish Spill/Bypass			None	
	Other Spill	2200 cfs	62.3 m^3/s	All periods	With fish ladder
Priest Rapids (1160)	Minimum Flow			Limit removed	
	Fish Spill/Bypass			None	
	Other Spill	2200 cfs	62.3 m^3/s	All periods	With fish ladder
Brownlee (767)	Minimum Flow	5850 cfs	165.7 m^3/s	All years, all periods in CP & LT studies.	4-04 C. Henriksen
	Downstream Minimum Flow	13000 cfs	368.1 m^3/s	July-Sep in all years for navigation requirement downstream at Lime Point (project #760). Draft Brownlee to help meet this requirement in CP and LT studies.	4-04 C. Henriksen

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	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	2.8 m^3/s	All periods	
Ice Harbor (502)	Fish Spill/Bypass			None	
	Other Spill	740 cfs	21.0 m^3/s	All periods	
	Incremental Spill			None	
	Minimum Flow			None	
	Other	204.8 ksfd 440.0 ft	83.7 hm^3 134.11 m	Run at all periods	
McNary (488)	Other Spill	3475 cfs	98.4 m^3/s	All periods	
	Incremental Spill			None	
John Day (440)	Fish Spill/Bypass			None	
	Other Spill	800 cfs	22.7 m^3/s	All periods	
	Incremental Spill			None	
	Minimum Flow	50000 cfs 12500 cfs	1415.8 m^3/s 354.0 m^3/s	Mar - Nov Dec - Feb	
	Other Step I:	269.7 ksfd 268.0 ft	659.8 hm^3 81.69 m	June - Aug 15	In place AOP80
		242.5 ksfd 267.0 ft	593.3 hm^3 81.38 m	Aug 31 - Sep	
		153.7 ksfd 263.6 ft	376.0 hm^3 80.35 m	Oct - Mar	
		114.9 ksfd 262.0 ft	281.1 hm^3 79.86 m	Apr - May	
	Steps II & III:	190.0 ksfd 265.0 ft	464.8 hm^3 80.77 m	Use JDA as run-of-river plant.	
The Dalles (365)	Fish Spill/Bypass			None	
	Other Spill	1300 cfs	36.8 m^3/s	All periods	
	Incremental Spill			None	
	Minimum Flow	50000 cfs 12500 cfs	1415.8 m^3/s 354.0 m^3/s	Mar - Nov Dec - Feb	

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Bonneville (320)	Fish Spill/Bypass			None	
	Other Spill	8040 cfs	227.7 m^3/s	All periods	
	Incremental Spill			None	
Kootenay Lake Corra Linn (1665)	Minimum Flow	5000 cfs	141.6 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	50 cfs	1.4 m^3/s	All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	308.5 ksfd	126.1 hm^3	Jul - Sep (except as needed to empty at end of critical period).	In place in AOP79, AOP80, AOP84
		1098.0 ft	334.7 m		
Couer d'Alene L.(1341)	Minimum Flow	50 cfs	1.4 m^3/s	All periods	In place in AOP79.
	Minimum Content	112.5 ksfd	275.2 hm^3	May - Aug	
		2128.0 ft	648.6 m	Flood control may override these minimum contents.	2-1-00 PNCA submittal
Post Falls (1340)	Minimum Flow	50 cfs	1.4 m^3/s	All periods	In place in AOP79, AOP80, AOP84.
<u>Other Major Step I Projects</u>					
Libby (1760)	Minimum Flow	4000 cfs	113.3 m^3/s	All periods	
	Other Spill	200 cfs	5.7 m^3/s	All periods	
	Minimum Content	By contract year: Aug-Jul i.e., 1929 = Aug 1928 - Jul 1929			
		776.9 ksfd	1900.7 hm^3	1929 Dec	2-1-93 PNCA submittal, in plac in AOP99.
		2363.0 ft	720.24 m		
		676.5 ksfd	1655.1 hm^3	1929 Jan	
		2355.0 ft	717.80 m		
		603.6 ksfd	1476.8 hm^3	1929 Feb	
		2349.0 ft	715.98 m		
		2147.7 ksfd	5254.5 hm^3	1929 Jul	
		2443.0 ft	744.63 m		
		652.0 ksfd	1595.2 hm^3	1930 Dec	
		2353.0 ft	717.19 m		
		433.2 ksfd	1059.9 hm^3	1930 Jan	
		2334.0 ft	711.40 m		
		389.3 ksfd	952.5 hm^3	1930 Feb	
		2330.0 ft	710.18 m		
		348.5 ksfd	852.6 hm^3	1930 Mar	
		2326.0 ft	708.96 m		
		297.4 ksfd	727.6 hm^3	1930 Apr 15	
		2321.0 ft	707.44 m		
		444.2 ksfd	1086.8 hm^3	1930 Apr 30	
		2335.0 ft	711.71 m		
		499.1 ksfd	1221.1 hm^3	1930 May	
		2340.0 ft	713.23 m		
		1344.6 ksfd	3289.7 hm^3	1930 Jun	
		2402.0 ft	732.13 m		
		1771.9 ksfd	4335.1 hm^3	1930 Jul	

Appendix A
Project Operating Procedures for the 2009-10 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months: Apr=Apr.1-30, Apr.15=Apr.1-Apr.15, Apr30=Apr.15-Apr.30; Aug=Aug.1-31, Aug.15=Aug.1-15, Aug.31=Aug.16-31.

		2425.0 ft	739.14 m		
		317.8 ksfd	777.5 hm^3	1931 Dec	
		2323.0 ft	708.05 m		
		192.2 ksfd	470.2 hm^3	1931 Jan	
		2310.0 ft	704.09 m		
		103.1 ksfd	252.2 hm^3	1931 Feb-Apr 30	
		2300.0 ft	701.04 m		
		192.2 ksfd	470.2 hm^3	1931 May	
		2310.0 ft	704.09 m		
		676.5 ksfd	1655.1 hm^3	1931 Jun	
		2355.0 ft	717.80 m		
		868.0 ksfd	2123.6 hm^3	1931 Jul	
		2370.0 ft	722.38 m		
		174.4 ksfd	426.7 hm^3	1932 Dec	
		2308.0 ft	703.48 m		
		103.1 ksfd	252.2 hm^3	1932 Jan	
		2300.0 ft	701.04 m		
		0.0 ksfd	0.0 hm^3	Empty at end of CP***	
		2287.0 ft	697.08 m		
		776.9 ksfd	1900.7 hm^3	All Dec	
		2363.0 ft	720.24 m		
			0.0 hm^3		
		373.1 ksfd	152.5 hm^3	July 1930 - No more than this amount lower than July 1929.	2-1-94 PNCA submittal, in place in AOP00 and AOP01.
		857.1 ksfd	350.3 hm^3	July 1931 - No more than this amount lower than July 1930.	
		March - Implement PNCA 6(c)2(c).			
	Max Summer Draft	5.0 ft	1.52 m		
	Other			Operate to meet IJC orders for Corra Linn.	CRTOC agreement on procedures to implement 1938 IJC order.
Dworshak (535)	Minimum Flow	1300 cfs	36.8 m^3/s	All periods	2-11-02 PNCA submittal
	Maximum Flow	14000 cfs	396.4 m^3/s	All periods (model includes maximum 14000 cfs for all periods, but URC may override.)	2-11-02 PNCA submittal
		25000 cfs	707.9 m^3/s	Up to 25 kcfs for flood control all periods.	
	Minimum Content	395.8 ksfd	968.4 hm^3	SMIN Apr - Aug 31	
	Start 3 yr CP at:	395.8 ksfd	968.4 hm^3	Aug 15	
	End 3 yr CP at:	218.4 ksfd	534.3 hm^3	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 between	50000 cfs	1415.8 m^3/s	Jul - Aug 31	2-11-02 PNCA submittal
	and	55000 cfs	1557.4 m^3/s	Jul - Aug 31	
	Other Spill	100 cfs	2.8 m^3/s	All periods	

Appendix A
Project Operating Procedures for the 2009-10 Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months: Apr=Apr.1-30, Apr.15=Apr.1-Apr.15, Apr30=Apr.15-Apr.30; Aug=Aug.1-31, Aug.15=Aug.1-15, Aug.31=Aug.16-31.

Lower Granite (520)	Bypass Date			None	
	Other Spill	670 cfs	19.0 m^3/s	All periods	
	Incremental Spill			Removed	
	Fish Spill	85000 cfs	2406.9 m^3/s	Following fish spill only if regulated flow is greater-than or equal to this flow	2-3-04 PNCA submittal
		16867 cfs	477.6 m^3/s	Apr 15 [19 kcfs or 20 kcfs alternating for 13 days]	
		19533 cfs	553.1 m^3/s	Apr 30	
		19484 cfs	551.7 m^3/s	May	
		17917 cfs	507.4 m^3/s	June [19 kcfs or 20 kcfs alternating for 20 days]	
	Maximum Fish	40000 cfs	1132.7 m^3/s	Instantaneous	
	Minimum Flow	11500 cfs	325.6 m^3/s	Mar-Nov	
	Other	224.9 ksfd	550.2 hm^3	On MOP Apr - Oct 31.	
		733.0 ft	223.42 m		
		245.8 ksfd	601.4 hm^3	On full pool Nov 30 - Mar 31.	
		738.0 ft	224.94 m		
Little Goose (518)	Bypass Date			None	
	Other Spill	630 cfs	17.8 m^3/s	All periods	
	Incremental Spill			Removed	
	Fish Spill	85000 cfs	2406.9 m^3/s	Only if regulated flow at Lower Granite is greater than or equal to this value.	2-3-04 PNCA submittal
		16467 cfs	466.3 m^3/s	Apr 15 [(38000/2)*13/15]	
		19000 cfs	538.0 m^3/s	Apr 30 & May	
		12677 cfs	359.0 m^3/s	Jun [(38000/2)*20/30]	
	Maximum Fish Spill	38000 cfs	1076.0 m^3/s	Instantaneous	
	Minimum Flow	11500 cfs		Mar - Nov	
	Other	260.5 ksfd	106.5 hm^3	On MOP Apr - Aug 31.	
		633.0 ft	192.94 m		
		285.0 ksfd	697.3 hm^3	On full pool Sep 30 - Mar 31.	
		638.0 ft	194.46 m		
Lower Monumental (504)	Bypass Date			A bypass date of 2010 was assumed.	
	Other Spill	750 cfs	21.2 m^3/s	All periods	

Appendix A
Project Operating Procedures for the 2009-10
Assured Operating Plan and Determination of Downstream Power Benefits

Definition of split months: Apr=Apr.1-30, Apr.15=Apr.1-Apr.15, Apr30=Apr.15-Apr.30; Aug=Aug.1-31, Aug.15=Aug.1-15, Aug.31=Aug.16-31.

	Fish Spill	85000 cfs	2406.9 m^3/s	Following fish spill only if regulated flow at Lower Granite is greater than or equal to this value.	2-3-04 PNCA submittal
		14733 cfs	417.2 m^3/s		
		17000 cfs	481.4 m^3/s	Apr 30 & May	
		11333 cfs	320.9 m^3/s	Jun [(34000/2)*20/30]	
	Maximum Fish Spill	34000 cfs	962.8 m^3/s	Instantaneous	
	Minimum Flow	11500 cfs	325.6 m^3/s	Mar-Nov	
	Other	180.5 ksfd	441.6 hm^3	On MOP Apr - Aug 31.	
		537.0 ft	163.68 m		
		190.1 ksfd	465.1 hm^3	On full pool Sep 30 - Mar 31.	
		540.0 ft	164.59 m		
Cushman (2206)	Other Spill	100 cfs	2.8 m^3/s	All periods	
LaGrande (2188)	Other Spill	30 cfs	0.8 m^3/s	All periods	
White River (2160)	Other Spill	130 cfs	3.7 m^3/s	All periods	
Round Butte (390)	Other Spill	200 cfs	5.7 m^3/s	All periods	
	Minimum Content	124.6 ksfd	304.8 hm^3	Nov - Apr 30	3-6-01 PNCA submittal
		1938.0 ft	590.70 m		
		130.6 ksfd	319.5 hm^3	May	
		1941.0 ft	591.62 m		
		136.3 ksfd	333.5 hm^3	Jun - Oct	
		1944.0 ft	592.53 m		
Timothy (117)	Minimum Content	24.5 ksfd	59.9 hm^3	Oct - May	3-6-01 PNCA submittal
		3180.0 ft	969.26 m		
		31.1 ksfd	76.1 hm^3	Jun - Aug 31	
		3190.0 ft	972.31 m		
		27.8 ksfd	68.0 hm^3	Sep. [(24.5*15+31.1*15)/30]	
		3185.0 ft	970.79 m		
Long Lake (1305)	Minimum Content	50.1 ksfd	122.6 hm^3	Apr - Nov	2-5-02 PNCA submittal
		1535.0 ft	467.87 m		
		19.7 ksfd	48.2 hm^3	Dec - Mar	
		1522.0 ft	463.9 m		
	Draft Limit	1.0 ft/day	0.30 m/day		2-1-03 PNCA submittal
Priest Lake (1470)	Maximum Content	0.0 ksfd	0.0 hm^3	Oct	2-1-03 PNCA submittal
		0.0 ft	0.00 m		
	Max/Min Content	35.5 ksfd	86.9 hm^3	Maintain at or near after runoff through Sep.	
		3.0 ft	0.91 m		
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 2009-10

TABLE OF CONTENTS

DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB) FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2009-10

November 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 2009-10 Determination of Downstream Power Benefits (DDPB10) developed from the 2009-10 Assured Operating Plan (AOP10).

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/DDPBs, and Operating Procedures for the 2001-02 and Future AOPs," signed 29 August 1996 (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, including the update to Appendix 1, dated 18 November 2003, and the November 2004 addition of Appendix 6, Streamline Procedures, and Appendix 7, Table of Median Streamflows.

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 use only the first of the three Streamline Procedures, "Forecasting Loads and Resources," as defined in Appendix 6 of the POP.

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 (km^3) (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 United States.

As part of the DDPB10, separate determinations may be carried out relating to the limit of year-to-year reduction 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 2009-10 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	= 1352.3 megawatts (MW)
Average Annual Usable Energy	= 567.1 average annual MW

All downstream power benefit 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 3.9 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 DDPB10, 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 AOP10.

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) 2002 White Book (WB02) load forecast, dated December 2002 and published November 2003. 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 2009-10 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 2009-10 Assured Operating Plan:

A. Joint Optimum Generation in Canada and the USA;

B. Optimum Generation in the USA Only; and

C. Optimum Generation in the USA and a 0.62 km^3 (0.5 Maf) Reduction in Total Canadian Treaty Storage.

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 shown on this table, but are not applicable 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 illustrate 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 agree that remaining usable energy is computed on the basis of 40 % of the nonfirm energy remaining after thermal displacement.

6. Summary of Changes from Previous Year and Notable Assumptions

Data from recent DDPBs are summarized in Table 6. An explanation of the more important changes and notable assumptions that impact computation of the entitlement compared to the DDPB10 studies follows.

a) Loads

Loads for the AOP/DDPB10 were based on BPA's WB02 medium-case load forecast. This load forecast shows a large reduction in direct service industry (mainly aluminum) loads. The net effect of the new load forecast is that the AOP10 PNWA firm load is 2,227 aMW (9.1%) less than the AOP09. After the AOP/DDPB10 studies were started in January 2004, there have been two new regional load forecasts. The BPA WB03 forecast, dated December 2003 and published in July 2004, for operating year 2009-10, is 4.9% lower than the WB02. However, the Northwest Power and Conservation Council's Fifth Power Plan regional load forecast, published in September 2004, is about 2.5% higher than the WB02 for the 2009-10 operating year. Other load assumptions and 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 Canadian Entitlement in the Step I system was based on a preliminary calculation of the 2009-10 Energy Entitlement from the WB02. The estimated and the computed Canadian Entitlement are shown below:

During 1 August 2009 – 31July 2010

Canadian Entitlement Return	Energy (aMW)		Capacity (MW)	
	Estimated	Computed	Estimated	Computed
Export to BC (1/2)	262.0	283.6	588.0	676.1
Retained in PNW (1/2)	262.0	283.6	588.0	676.1
Total	524.0	567.1	1176.0	1352.3

Iterative studies to update the Canadian Entitlement in the load estimate were not performed because the effect on the size of the thermal installations is less than one-fourth of one per-cent and therefore would not significantly affect the results of the studies.

- Compared to the AOP09, Flows-Out (exports, mostly to the Southwest) decreased by 134 aMW, mainly due to expiration of several firm contracts. Flows-In (imports) decreased by 26 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 is a 33 aMW decrease in Miscellaneous Non-Thermal Resources, mainly wind generators.

b) Thermal Installations

Because of increasing difficulty in forecasting Thermal Installations, the Entities used the Streamline Procedure, "Loads and Resources," for determining Thermal Installations, as used in the 2006-07, 2007-08, and 2008-09 AOPs. The procedure assumes 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 critical period hydro capability. The annual shape of the 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. So CGS maintenance was not included in the 2009-10 study. Because of the large decrease in PNW Area firm load and a decrease in exports minus imports, the Thermal Installations decreased by 2,304 aMW compared to the AOP09.

The TDM decreased by 2,139 aMW due to the combination of decreased thermal installations explained above (2,304 aMW), a decrease in system sales (114.5 aMW), and a slight increase (49.9 aMW) in Minimum Thermal Generation.

c) Hydro Project Modified Streamflows

- The base unregulated streamflows used in the System Regulation Studies were updated from the 1990 level used in the previous AOP/DDPB studies to the 2000 Modified Streamflows published by BPA in May 2004. Modified Streamflows are determined from historic observed stream flows, adjusted to remove the storage regulation effect at modeled upstream projects, and modified to a common level of irrigation depletions and reservoir evaporation. Total irrigation depletions changed slightly. The 60-year average Modified Flow at The Dalles increased by about 0.46%, mainly due to decreased depletions on Yakima and Deschutes rivers.
- Grand Coulee pumping estimates were updated from the February 2001 Pacific Northwest Coordination Agreement data submittal by the Bureau of Reclamation. The Grand Coulee return flows were also updated to reflect the difference between the Bureau update and the 2000 level Modified Flows.

- The Step II and III base streamflow added Lime Point to simplify the calculation of Brownlee minimum flow requirement.

d) Hydro Project Rule Curves

The critical rule curves, refill curves, and Mica/Arrow operating criteria were updated in accordance with procedures defined in the POP, except that the VRCLLs for Step II were not updated from the 2005-06 AOP (VRCLLs are not used in the Step III studies). Other changes and notable assumptions include:

- The agreed allocation of flood control space in Mica and Arrow was 5.03 and 4.44 km^3 (4.08 and 3.6 Maf), respectively. The URC data was the same as used in the 2006-07, 2007-08, and 2008-09 AOPs. In the 2005-06 and prior AOPs the flood control allocation was 2.57 and 6.29 km^3 (2.08 and 5.1 Maf).

- All of the flood control rule curves in the Step II and III studies were the same as the AOP10 Step I study. The Grand Coulee URC in the 2006-07 through 2009-10 AOP/DDPBs is different than 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.

- The APOC referred to in AOP10 subsection 4(c)2 was changed from the three prior AOPs. APOC is implemented through use of maximum outflows and maximum storage limits.

- Distribution factors for Grand Coulee and Hungry Horse, used in the calculation of variable refill curves, were updated.

- The Brownlee storage operation outside the critical period was simulated by using CRCs and ORCs instead of the fixed operation from Idaho Power Company (IPC) used in the 2003-04 and previous AOPs. The CRCs 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. ORCs were revised from the AOP09 to more closely follow the historic forecast of IPC operation while including the updated 2000 level modified flows and Lime Point minimum flow requirements.

- Coeur d'Alene Lake flood control was updated.

e) Hydro Project Operating Procedures

The nonpower requirements for Base system projects were agreed to in the 1996 Entity Agreement. These requirements are essentially the nonpower requirements included in the 1979-80 and prior AOP/DDPB studies. Other changes and notable assumptions include:

- Brownlee minimum flow requirements were changed to 166 m^3/s, (5,850 cfs) in all periods plus the flow needed to reach 368 m^3/s (13,000 cfs) at Lime Point during July through September.

- Generation plant data tables for Noxon were updated.

- Generation plant data tables for Arrow and Brilliant were updated. These changes did not significantly affect the system operation.

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

Step II and Step III critical period regulation studies for the 2009-10 operating year were performed to establish critical period capability as described in Section 2.2.A of the POP. The Step II and Step III critical streamflow periods were the same as the DDPB09 studies. The Step II critical period was the 20 calendar-months from 1 September 1943 through April 30, 1945, and the Step III study critical period was the 5.5 calendar-months from 1 November 1936 through 15 April 1937.

For the 30-year System Regulation Studies, the Entities conducted a full set of Step II (-42, -12, and -22) and Step III (-13) 30-year System Regulation Studies as described in Section 3.3 of the POP.

g) Downstream Power Benefits

The Canadian Capacity Entitlement increased from 1245.2 MW in the 2008-09 DDPB (DDPB09) to 1352.3 MW in the DDPB10, an increase of 107.1 MW. The change was mostly due to a 111.4 MW decrease in the Step III average critical period generation and a 1.9% decrease in the average critical period load factor. The change in Step III critical period generation is primarily caused by the change in the seasonal shape of irrigation depletions in the 2000 Modified Flows and a new flood control rule curve at Coeur d'Alene Lake that causes pre-critical period draft. The decreased CP load factor is due to the large decrease in aluminum company load which had a high load factor.

The Canadian Energy Entitlement increased from 464.9 aMW in the DDPB09 to 567.1 aMW in the DDPB10 for an increase of 102.2 aMW. The change was mostly due to the 2,139 aMW decrease in the TDM, which accounted for roughly 80% of the change in the Energy Entitlement. The Energy Entitlement was also affected by the change in irrigation depletions and by the effect on Step II and Step III seasonal hydro load shape from the greatly reduced thermal installation size.

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

2009-10 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/	21754	21754	20475	20951	23178	25363	25816	24812	22887	21768	21743	21051	21568	22331	22654.3	22753.1
b) Remove Utah Load (Flow-through-transfer)	-497	-497	-362	-313	-322	-292	-357	-357	-338	-323	-323	-362	-518	-588	-386.1	-380.0
c) .....Total PNWA Firm Load for Step 1 4/	**21258**	**21258**	**20114**	**20639**	**22855**	**25071**	**25459**	**24455**	**22548**	**21445**	**21420**	**20689**	**21050**	**21743**	**22268.2**	**22373.0**
d) Annual Load Shape in Percent	95.46	95.46	90.32	92.68	102.64	112.59	114.33	109.82	101.26	96.30	96.19	92.91	94.53	97.64	100.00	100.5
2. Flows-Out of firm power from PNWA																
a) WB Exports 5/	935	935	924	870	873	890	888	883	875	897	896	862	964	961	901.6	900.1
b) Remove WB Canadian Entitlement export	-524	-524	-524	-524	-524	-524	-524	-524	-524	-524	-524	-524	-524	-524	-524.0	-524.0
c) Add estimated Entitlement Export (south+north) 6/	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262.0	262.0
d) Added Seasonal Exchange Export 7/	399	405	1082	0	0	0	0	0	0	0	894	2692	2974	1524	762.4	675.8
e) ...Subtotal for Table 2	1072	1078	1743	608	611	628	626	621	613	635	1529	3292	3676	2223	1402.0	1313.9
f) Remove SPP Flow-through-transfer	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75	-60.0	-58.8
g) Remove Plant Sales	-166	-166	-166	-166	-166	-166	-166	-166	-166	-166	-166	-44	-162	-166	-155.4	-157.0
h) ...Total	**831**	**837**	**1502**	**397**	**399**	**417**	**415**	**410**	**402**	**394**	**1288**	**3172**	**3439**	**1982**	**1186.6**	**1098.0**
3. Flows-In of firm power except from coordinated thermal installations																
a) WB Imports 8/	-624	-624	-518	-512	-722	-763	-814	-780	-714	-644	-613	-470	-648	-736	-660.2	-663.2
b) Remove Thermal Installations (- PP&I - PSW Thermal)	35	35	68	136	320	381	354	311	271	218	187	7	18	49	178.6	188.6
c) Remove Utah Import (Flow-Through-Transfer)	497	497	362	313	322	292	357	357	338	323	323	362	518	588	386.1	380.0
d) Remove SPP Flow-through-transfer	75	75	75	45	45	45	45	45	45	75	75	75	75	75	60.0	58.8
e) Added Seasonal Exchange Import 7/	0	0	0	-511	-1221	-1515	-2042	-2372	-1070	-1065	0	0	0	0	-762.4	-824.7
f) ...Total	**-18**	**-18**	**-13**	**-529**	**-1255**	**-1560**	**-2100**	**-2439**	**-1130**	**-1092**	**-27**	**-26**	**-36**	**-24**	**-797.8**	**-860.4**
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)	-486	-449	-540	-922	-935	-981	-890	-605	-655	-796	-770	-702	-1320	-605	-784.0	-812.3
c) Misc Non-thermal Resources (from input_data)	-529	-529	-428	-426	-457	-423	-432	-430	-457	-564	-563	-668	-689	-589	-507.9	-497.6
d) ...Total (1929)	**-2296**	**-2232**	**-2143**	**-2549**	**-2623**	**-2563**	**-2424**	**-1959**	**-2157**	**-2641**	**-2660**	**-3142**	**-3736**	**-2620**	**-2571.7**	**-2453.8**
5. Total Step I System Loads (1929 water) 9/	**19775**	**19845**	**19460**	**17957**	**19376**	**21366**	**21350**	**20467**	**19663**	**18106**	**20020**	**20694**	**20717**	**21082**	**20085.3**	**20156.8**
6. Step I Coordinated Thermal Installations																
a) Columbia Generating Station (WNP2)	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000.0	1000.0
b) Thermal Installations to meet firm load 10/	8153	8152	8159	8105	8158	8153	8164	8170	8007	7319	6974	6924	6972	8012	7843.6	7890.7
c) ...Total	**9153**	**9152**	**9159**	**9105**	**9158**	**9153**	**9164**	**9170**	**9007**	**8319**	**7974**	**7924**	**7972**	**9012**	**8843.6**	**8890.7**
7. Total Step I Hydro Load (1929 water) 11/	**10622**	**10692**	**10301**	**8852**	**10219**	**12212**	**12186**	**11296**	**10656**	**9787**	**12046**	**12769**	**12745**	**12070**	**11241.7**	**11266.1**
a) Hydro Maintenance included as load	30	25	9	9	4	0	0	0	5	7	8	20	14	49	12.2	11.2
b) Coordinated Hydro Model Load (1929) 12/	**11138**	**11166**	**10850**	**9783**	**11157**	**13193**	**13076**	**11901**	**11316**	**10590**	**12823**	**13491**	**14079**	**12724**	**12037.9**	**12089.6**
c) Coordinated Hydro Model Load shape (1929) 12/	92.52%	92.76%	90.13%	81.27%	92.69%	109.60%	108.62%	98.87%	94.00%	87.97%	106.53%	112.07%	116.96%	105.70%	100.00%	

Notes:

1/ Step I Loads and Resources for the U.S. Optimum Study (09-10) as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements. The annual average (aMW) does not include 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 2002 BPA White Book.

4/ In accordance with the Protocal 10, the Total PNWA Firm Load includes 110 aMW of Grand Coulee pumping (148 aMW of total pumping), but excludes the Utah load.

5/ White Book exports include Firm Seasonal Exchanges, Flow-Through Transfers, Plant Sales, and the full Canadian Entitlement.

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

7/ Added Seasonal Exchange which balances annually. See lines 2(d) and 3(e).

8/ White Book Imports include thermal installations, firm seasonal exchange, flow-through-transfers, and Skagit Treaty power.

9/ Line 1(c)+ line 2(h) + line 3(f) + line 4(d).

10/ 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.

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

12/ 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
2009-10 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/	29291	29291	27860	29086	32683	35471	36740	35333	32314	30278	30278	29154	29205	30016
b) Remove Utah Load (Flow-through-transfer)	-597	-597	-478	-370	-387	-295	-453	-399	-419	-363	-363	-386	-642	-674
c) Remove Federal Peak Diversity	-889	-889	-899	-886	-817	-626	-638	-624	-830	-778	-778	-890	-884	-901
d) .....Total PNWA Firm Load for Step 1 3/	**27805**	**27805**	**26483**	**27831**	**31479**	**34551**	**35649**	**34311**	**31065**	**29137**	**29137**	**27878**	**27678**	**28441**
e) Monthly Load Factors in Percent	76.45	76.45	75.95	74.16	72.60	72.56	71.42	71.27	72.58	73.60	73.51	74.21	76.05	76.45
2. Flows-Out of firm power from PNWA														
a) WB Exports 4/	1857	1857	1827	1728	1698	1724	1720	1714	1701	1720	1720	1768	1862	1875
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) 5/	588	588	588	588	588	588	588	588	588	588	588	588	588	588
d) Added Seasonal Exchange Export 6/	399	405	1082	0	0	0	0	0	0	0	894	2692	2974	1524
e) ...Subtotal for Table 2	1668	1674	2320	1140	1110	1135	1132	1125	1113	1131	2026	3871	4247	2811
f) Remove SPP Flow-through-transfer	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75
g) Remove Plant Sales	-183	-183	-183	-183	-183	-183	-183	-183	-183	-183	-183	-45	-183	-183
h) ...Total	**1410**	**1416**	**2062**	**912**	**882**	**907**	**904**	**897**	**885**	**873**	**1768**	**3751**	**3989**	**2553**
3. Flows-In of firm power except from coordinated thermal installations														
a) WB Imports 7/	-716	-716	-634	-588	-718	-797	-857	-844	-785	-674	-674	-510	-745	-808
b) Remove Thermal Installations (- PP&I - PSW Thermal)	13	13	42	108	313	389	363	319	261	200	200	0	18	34
c) Remove Utah Import (Flow-Through-Transfer)	485	485	375	293	263	244	300	298	271	257	257	293	509	556
d) Remove SPP Flow-through-transfer	75	75	75	45	45	45	45	45	45	75	75	75	75	75
e) Added Seasonal Exchange Import 6/	0	0	0	-511	-1221	-1515	-2042	-2372	-1070	-1065	0	0	0	0
f) ...Total	**75**	**75**	**75**	**-466**	**-1176**	**-1470**	**-1997**	**-2327**	**-1025**	**-990**	**75**	**75**	**75**	**75**
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)	-2487	-2429	-2530	-2472	-2372	-2294	-1498	-1330	-2022	-2036	-2082	-2046	-2347	-2528
c) Misc Non-thermal resources (from input_data)	-571	-571	-477	-471	-487	-450	-461	-464	-485	-581	-581	-688	-694	-606
d) ...Total (1937)	**-5108**	**-5027**	**-4944**	**-4730**	**-4492**	**-4338**	**-3507**	**-3458**	**-4294**	**-4612**	**-4666**	**-4903**	**-5250**	**-5249**
5. Total Step I System Firm Loads (1937water) 8/	**24182**	**24269**	**23676**	**23547**	**26693**	**29650**	**31049**	**29423**	**26631**	**24409**	**26315**	**26801**	**26493**	**25820**
6. Step I Coordinated Thermal Installations														
a) Columbia Generating Station (WNP2)	1162	1162	1162	1162	1162	1162	1162	1162	1162	1162	1162	1162	1162	1162
b) Thermal Installations to meet firm load 9/	8582	8582	8589	8532	8587	8582	8594	8600	8429	7704	7341	7289	7339	8433
c) ...Total	**9744**	**9744**	**9751**	**9694**	**9749**	**9744**	**9756**	**9762**	**9591**	**8866**	**8503**	**8451**	**8501**	**9595**
7. Step I Hydro Load (1937 water) 10/	14438	14525	13926	13853	16944	19906	21293	19661	17040	15543	17811	18351	17992	16225
a) Hydro Maintenance included as load	4595	4032	3787	3208	2935	2037	1561	2286	2626	2751	2483	2360	2202	3720
b) Coordinated Hydro Model Load (1937 water) 11/	21519	20986	20243	19534	22251	24237	24353	23277	21688	20330	22376	22756	22541	22473

Note:

1/ Step I Loads and Resources for the U.S. Optimum Study (09-10) 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 2002 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/ White Book exports include Firm Seasonal Exchanges, Flow-Through Transfers, Plant Sales, and the full Canadian Entitlement.

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

6/ Added Seasonal Exchange which is the same as the average energy Added Sersonal Exchange from Table 1a, line 3(e).

7/ White Book Imports include thermal installations, firm seasonal exchange, flow-through-transfers, and Skagit Treaty power

8/ Line 1(d)+ line 2(h) + line 3(f) + line 4(d).

9/ Peak generation for thermal installations is the energy generation from Table 1a, line 6b divided by 95% plant factor.

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 2

2009-10 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)	9153	9152	9159	9105	9158	9153	9164	9170	9007	8319	7974	7924	7972	9012	8843.6	8890.7
2. DISPLACEABLE THERMAL RESOURCES																
a) Minimum Generation as a % of Thermal Install	203	203	203	202	203	203	203	203	199	182	174	172	174	199	195.3	196.5
b) Net Displaceable Thermal Resources	**8950**	**8949**	**8956**	**8903**	**8954**	**8950**	**8961**	**8967**	**8808**	**8136**	**7801**	**7752**	**7798**	**8812**	**8648.3**	**8694.2**
3. SYSTEM SALES																
a) Flows-Out (Table 1A, Line 2(e))	1072	1078	1743	608	611	628	626	621	613	635	1529	3292	3676	2223	1402.0	1313.9
b) Exclude Firm Seasonal Exchanges	-28	-28	-39	-15	0	0	0	0	0	0	0	-28	-67	-39	-18.0	-16.8
c) Exclude Added Seasonal Exchanges	-399	-405	-1082	0	0	0	0	0	0	0	-894	-2692	-2974	-1524	-762.4	-675.8
d) Exclude Plant Sales	-166	-166	-166	-166	-166	-166	-166	-166	-166	-166	-166	-44	-162	-166	-155.4	-157.0
e) Exclude Flow-Through Transfers	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75	-60.0	-58.8
f) Exclude Canadian Entitlement Export	-262	-262	-262	-262	-262	-262	-262	-262	-262	-262	-262	-262	-262	-262	-262.0	-262.0
g) ...Total System Sales	**142**	**142**	**120**	**120**	**137**	**155**	**153**	**148**	**140**	**132**	**131**	**190**	**136**	**157**	**144.3**	**143.5**
h) Uniform Average Annual System Sales	144	144	144	144	144	144	144	144	144	144	144	144	144	144	144.3	144.3
4. THERMAL DISPLACEMENT MARKET	**8806**	**8805**	**8812**	**8759**	**8810**	**8806**	**8817**	**8823**	**8664**	**7992**	**7656**	**7608**	**7654**	**8668**	**8504.0**	**8550.0**

Notes:

Line 2a Minimum generation is 0.0249 times the annual average Step 1 thermal, without CGS; based on 2006 AOP.

Line 3a Flows-Out include firm seasonal exchange exports; added seasonal exchanges, plant sales, flow-through-transfers, and Canadian Entitlement Exports.

Line 3b Firm Seasonal Exchange Exports included in Line 3(a) are supported by Firm Seasonal Exchange Imports.

Line 3c Added Seasonal Exchange Exports (Line 2(d), Table 1A) are supported by Added Seasonal Exchange imports.

Line 3d Plant sales include Longview Fibre and approximately 25 percent of Boardman; line 2(g), Table 1A. They are excluded here because also excluded on Table 1 calc of thermal.

Line 3e Flow through transfers are Flows-in that support the same Flows-Out in the same period. This is a wheel to outside the region and back in to meet a regional (So. OR) load.

Line 3f Canadian Entitlement is assumed to be supported by hydro instead of thermal.

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

Line 3h 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(h).

TABLE 3
2009-10 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	21258	95.46	27805	76.45	9153	16945.0	7791.7	14335.6	5182.2	Aug. 1-15
Aug. 16-31	21258	95.46	27805	76.45	9152	16945.0	7792.5	14335.6	5183.1	Aug. 16-31
September	20114	90.32	26483	75.95	9159	16032.9	6873.7	13564.0	4404.7	September
October	20639	92.68	27831	74.16	9105	16451.4	7346.4	13917.9	4813.0	October
November	22855	102.64	31479	72.60	9158	18218.4	9060.8	15412.9	6255.3	November
December	25071	112.59	34551	72.56	9153	19984.5	10831.2	16907.0	7753.7	December
January	25459	114.33	35649	71.42	9164	20294.0	11129.6	17168.8	8004.4	January
February	24455	109.82	34311	71.27	9170	19493.3	10323.0	16491.4	7321.1	February
March	22548	101.26	31065	72.58	9007	17973.7	8966.3	15205.9	6198.5	March
April 1-15	21445	96.30	29137	73.60	8319	17094.3	8775.7	14461.9	6143.3	April 1-15
April 16-30	21420	96.19	29137	73.51	7974	17074.2	9099.9	14444.8	6470.6	April 16-30
May	20689	92.91	27878	74.21	7924	16491.6	8567.4	13952.0	6027.8	May
June	21050	94.53	27678	76.05	7972	16779.2	8807.5	14195.3	6223.6	June
July	21743	97.64	28441	76.45	9012	17331.9	8320.3	14662.9	5651.2	July
Annual Average 7/ =	22268.2	100.00		73.95	8843.6	17750.4	8906.8	15016.9	6173.4	Annual Avg
SI CP avg(42.5) =	22373.0			73.85	8890.7					
S2 CP avg(20) =	22490.7				8909.7	17927.8	9018.1			<==Sep-Ap30
S3 CP avg(5.5) =	23840.4				9056.3			16077.1	7020.8	<==Nov-Ap15
						Input 5/=	9018.10	Input 6/=	7020.80	
August 1-31	21257.9	95.5	27805.1	76.45	9152.9	16945.0	7792.1	14335.6	5182.7	Aug. 1-31
April 1-30	21432.6	96.2	29137.4	73.56	8146.5	17084.3	8937.8	14453.4	6306.9	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 2009-10 operating year. The critical period (CP) averages are for the historic water years.

TABLE 4
(English Units)
SUMMARY OF POWER REGULATIONS
FROM 2009-10 ASSURED OPERATING PLAN

PROJECTS	BASIC DATA: NUMBER OF UNITS	BASIC DATA: MAXIMUM INSTALLED PEAKING CAPACITY MW	STEP I: USABLE STORAGE kaf	STEP I: JANUARY 1937 PEAKING CAP. MW	STEP I: CRITICAL PERIOD AVERAGE GEN. MW	STEP II: USABLE STORAGE kaf	STEP II: JANUARY 1946 PEAKING CAP MW	STEP II: CRITICAL PERIOD AVERAGE GEN. MW	STEP II: 30 YEAR AVERAGE ANNUAL GEN. MW	STEP III: USABLE STORAGE kaf	STEP III: JANUARY 1937 PEAKING CAP MW	STEP III: CRITICAL PERIOD AVERAGE GEN. MW	STEP III: 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	270	100	3008	191	114	103	3008	328	245	105
Kerr	3	160	1219	178	123	1219	174	112	130	1219	174	156	123
Thompson Falls	6	85	0	85	55	0	85	53	59	0	85	66	57
Noxon Rapids	5	554	231	524	148	0	528	130	197	0	528	175	197
Cabinet Gorge	4	239	0	239	101	0	239	91	119	0	239	116	117
Albeni Falls	3	50	1155	21	23	1155	19	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	6365	2062	5072	6364	1849	2403	5072	5604	1221	2289
Chief Joseph	27	2535	0	2535	1070	0	2535	972	1310	0	2535	707	1237
Wells	10	840	0	840	421	0	840	389	490	0	840	287	441
Chelan	2	54	677	51	38	676	51	38	44	676	51	51	43
Rocky Reach	11	1267	0	1267	575	0	1267	532	695	0	1267	387	644
Rock Island	18	513	0	513	256	0	513	239	302	0	513	176	278
Wanapum	10	986	0	986	519	0	986	481	606	0	986	340	537
Priest Rapids	10	912	0	912	510	0	912	476	578	0	912	347	507
Brownlee	5	675	975	675	243	974	675	312	326	974	675	264	323
Oxbow	4	220	0	220	100	0	220	126	130	0	220	116	129
Ice Harbor	6	693	0	693	214	0	693	231	303	0	693	163	303
McNary	14	1127	0	1127	627	0	1127	604	772	0	1127	445	716
John Day	16	2484	535	2484	943	0	2484	920	1256	0	2484	687	1215
The Dalles	22+2F	2074	0	2074	751	0	2074	733	996	0	2074	565	971
Bonneville	18+2F	1088	0	1047	566	0	1047	551	684	0	1047	435	640
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	23176	9491	28500	23093	9018	11571	13000	22466	7021	10940
ADDITIONAL STEP I PROJECTS						NOT APPLICABLE TO STEP II & III							
Libby	5	600	4980	542	197								
Boundary	6	1055	0	855	367								
Spokane River Plants 2/	24	173	104	168	98								
Hells Canyon	3	450	0	441	198								
Dworshak	3	450	2015	443	151								
Lower Granite	6	932	0	930	213								
Little Goose	6	932	0	928	210								
Lower Monumental	6	932	0	922	216								
Pelton, Rereg., & RB	7	423	274	419	136								
Total added step 1		5947	7373	5649	1786								
THERMAL INSTALLATION 3/				9756	8891		9756	8910			9756	9056	
RESERVES, HYDRO MAINTENANCE 4/				-4413	-11		-2320	0			-1851	0	
TOTAL RESOURCES				34168	20156		30530	17928			30371	16077	
STEP I, II, & III LOADS 5/				31049	20157		28996	17928			23142	16077	
SURPLUS				3118	0		1533	0			7229	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			10-41			10-42				10-13		

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 4M
(Metric Units)
SUMMARY OF POWER REGULATIONS
FROM 2009-10 ASSURED OPERATING PLAN

	BASIC	DATA	STEP I			STEP II				STEP III 4/			
PROJECTS	NUMBER OF UNITS	NOMINAL INSTALLED PEAKING CAPACITY MW	USABLE STORAGE hm3	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE hm3	JANUARY 1946 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE hm3	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	270	100	3710	191	114	103	3710	328	245	105
Kerr	3	160	1504	178	123	1504	174	112	130	1504	174	156	123
Thompson Falls	6	85	0	85	55	0	85	53	59	0	85	66	57
Noxon Rapids	5	554	285	524	148	0	528	130	197	0	528	175	197
Cabinet Gorge	4	239	0	239	101	0	239	91	119	0	239	116	117
Albeni Falls	3	50	1425	21	23	1425	19	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	6365	2062	6256	6364	1849	2403	6256	5604	1221	2289
Chief Joseph	27	2535	0	2535	1070	0	2535	972	1310	0	2535	707	1237
Wells	10	840	0	840	421	0	840	389	490	0	840	287	441
Chelan	2	54	835	51	38	834	51	38	44	834	51	51	43
Rocky Reach	11	1267	0	1267	575	0	1267	532	695	0	1267	387	644
Rock Island	18	513	0	513	256	0	513	239	302	0	513	176	278
Wanapum	10	986	0	986	519	0	986	481	606	0	986	340	537
Priest Rapids	10	912	0	912	510	0	912	476	578	0	912	347	507
Brownlee	5	675	1203	675	243	1201	675	312	326	1201	675	264	323
Oxbow	4	220	0	220	100	0	220	126	130	0	220	116	129
Ice Harbor	6	693	0	693	214	0	693	231	303	0	693	163	303
McNary	14	1127	0	1127	627	0	1127	604	772	0	1127	445	716
John Day	16	2484	660	2484	943	0	2484	920	1256	0	2484	687	1215
The Dalles	22+2F	2074	0	2074	751	0	2074	733	996	0	2074	565	971
Bonneville	18+2F	1088	0	1047	566	0	1047	551	684	0	1047	435	640
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	23176	9491	35155	23093	9018	11571	16036	22466	7021	10940
ADDITIONAL STEP I PROJECTS						NOT APPLICABLE TO STEP II & III							
Libby	5	600	6143	542	197								
Boundary	6	1055	0	855	367								
Spokane River Plants 2/	24	173	128	168	98								
Hells Canyon	3	450	0	441	198								
Dworshak	3	450	2486	443	151								
Lower Granite	6	932	0	930	213								
Little Goose	6	932	0	928	210								
Lower Monumental	6	932	0	922	216								
Pelton, Rereg., & RB	7	423	338	419	136								
Total added step 1		5947	9095	5649	1786								
THERMAL INSTALLATION 3/				9756	8891		9756	8910			9756	9056	
RESERVES, HYDRO MAINTENANCE 4/				-4413	-11		-2320				-1851	0	
TOTAL RESOURCES				34168	20156		30530	17928			30371	16077	
STEP I, II, & III LOADS 5/				31049	20157		28996	17928			23142	16077	
SURPLUS				3118	0		1533	0			7229	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		10-41			10-42				10-13			

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
(English & Metric Units)
COMPUTATION OF CANADIAN ENTITLEMENT FOR
2009-10 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S. (From 10-42)
B. Optimum Power Generation in the U.S. Only (From 10-12)
C. Optimum Power Generation in the U.S. and a 0.5 Million Acre-Feet (0.6 km^3) Reduction in Total Canadian Treaty Storage (From 10-22). For information only, not needed for this DDPB (see section 3).

Determination of Dependable Capacity Credited to Canadian Storage (MW)	**CAPACITY ENTITLEMENT**		
	(A)	(B)	(C)
Step II - Critical Period Average Generation 1/	9018.1	9018.1	8981.5
Step III - Critical Period Average Generation 2/	7020.8	7020.8	7020.8
Gain Due to Canadian Storage	1997.3	1997.3	1960.7
Average Critical Period Load Factor in percent 3/	73.85	73.85	73.85
Dependable Capacity Gain 4/	2704.5	2704.5	2655.0
Canadian Share of Dependable Capacity 5/	1352.3	1352.3	1327.5

Determination of Increase in Average Annual Usable Hydro Energy (aMW)	**ENERGY ENTITLEMENT**		
Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Firm Energy 6/	8907.7	8907.7	8871.5
Thermal Displacement Energy 7/	2444.1	2434.1	2454.0
Remaining Usable Energy 8/	87.6	89.7	92.4
System Average Annual Usable Energy	11439.4	11431.5	11417.9
Step III (without Canadian Storage) 2/			
Firm Energy 6/	6174.1	6174.1	6174.1
Thermal Displacement Energy 7/	3707.8	3707.8	3707.8
Remaining Usable Energy 8/	423.2	423.2	423.2
System Average Annual Usable Energy	10305.1	10305.1	10305.1
Average Annual Usable Energy Gain 9/	1134.3	1126.4	1112.8
Canadian Share of Average Annual Energy Gain 5/	567.1	563.2	556.4

1/ Step II values were obtained from the 10-42, 10-12, and 10-22 studies, respectively.
2/ Step III values were obtained from the 10-13 study and Table 3.
3/ Critical period load factor from Table 3.
4/ Dependable Capacity Gain credited to Canadian storage equals gain in critical period average generation divided by the average critical period load factor.
5/ One-half of Dependable Capacity or Usable Energy Gain.
6/ From 30-year average firm load served, which includes 7 leap years (29 days in February).
7/ Average secondary generation limited to Potential Thermal Displacement market.
8/ Forty percent (40%) of the remaining secondary energy.
9/ Difference between Step II and Step III Annual Average Usable Energy.

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

	2005-06	2006-07	2007-08	2008-09	2009-10
AVERAGE PNWA ENERGY LOAD					
Annual Load (MW)	22214.7	23734.4	24111.7	24495.5	22268.2
Annual/January Load (%)	88.2	87.4	87.4	87.3	87.5
Critical Period (CP) Load Factor (%)	76.5	75.7	75.8	75.7	73.9
Annual Firm Exports 1/	1073.5	867.6	718.7	704.7	639.6
Annual Firm Surplus (MW) 2/	876.9	701.2	798.2	747.3	762.4
THERMAL INSTALLATIONS (MW) 3/					
January Peak Capability	11486	11946	11856	12417	9756
CP Energy	10302	10587	10819	11228	8891
CP Minimum Generation	230	231	237	245	196
Average Annual System Export Sales	1232	353	255	259	144
Average Annual Displaceable Market	8785	9926	10270	10643	8504
HYDRO CAPACITY (MW)					
Total Installed	29689	29689	29689	29689	29689
Base System	23742	23742	23742	23742	23742
STEP I/II/III CP (MONTHS)	42.5/20/5.5	42.5/20/5.5	42.5/20/5.5	42.5/20/5.5	42.5/20/5.5
BASE STREAMFLOWS AT THE DALLES (cfs) 4/					
Step I 30-yr. Average Streamflow	176702	176702	176702	176702	175663
Step I CP Average	114401	114401	114401	114401	115061
Step II CP Average	101525	101525	101525	101525	101961
Step III CP Average	57184	57184	57184	57184	56558
BASE STREAMFLOWS AT THE DALLES (m^3/s) 4/					
Step I 30-yr. Average Streamflow	5003.64	5003.64	5003.64	5003.64	4974.22
Step I CP Average	3239.47	3239.47	3239.47	3239.47	3258.17
Step II CP Average	2874.87	2874.87	2874.87	2874.87	2887.22
Step III CP Average	1619.26	1619.26	1619.26	1619.27	1601.55
CAPACITY BENEFITS (MW)					
Step II CP Generation	9018.5	9020.0	9015.2	9018.7	9018.1
Step III CP Generation	7154.1	7135.1	7134.3	7132.2	7020.8
Step II Gain over Step III	1864.4	1884.9	1880.9	1886.5	1997.3
CANADIAN ENTITLEMENT	1218.0	1244.3	1240.9	1245.2	1352.3
Change due to Mica Reoperation	0.0	0.0	0.0	0.0	0.0
Benefit in Sales Agreement	0.0	0.0	0.0	0.0	0.0
ENERGY BENEFITS (aMW)					
Step II Annual Firm	8875.5	8928.2	8870.6	8921.2	8907.7
Step II Thermal Displacement	2473.7	2512.3	2586.5	2558.9	2444.1
Step II Remaining Usable Secondary	78.6	41.2	34.6	25.4	87.6
Step II System Average Annual Usable	11427.8	11481.7	11491.7	11505.5	11439.4
Step III Annual Firm	6272.1	6286.9	6150.8	6243.5	6174.1
Step III Thermal Displacement	3688.7	3922.6	4094.4	4084.5	3707.8
Step III Remaining Usable Secondary	396.7	295.2	280.8	247.7	423.2
Step III System Average Annual Average	10357.5	10504.7	10526.0	10575.7	10305.1
CANADIAN ENTITLEMENT	535.1	488.5	482.8	464.9	567.1
Change due to Mica Reoperation	1.8	1.5	1.7	1.9	3.9
ENTITLEMENT in Sales Agreement	0.0	0.0	0.0	0.0	0.0
STEP II PEAK CAPABILITY (MW)	32323	32607	32501	33008	30530
STEP II PEAK LOAD (MW)	28608	30550	30884	31564	28996
STEP III PEAK CAPABILITY (MW)	32174	32488	32381	32882	30371
STEP III PEAK LOAD (MW)	23394	24874	25063	25758	23142

NOTE: FOOTNOTES FOR TABLE 6 is located in Word "dop document"

FOOTNOTES FOR TABLE 6

1. Average annual firm exports do not include the firm surplus shape or the new Thermal Installation power used outside the region (exports to shape thermal installations), but does include plant sales.

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

AOP Study	Amount Shaped (MW)
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.
2007-08	894 Aug 15, 902 Aug 31, 1293 Sep, 449 Apr 30, 2544 May, 2711 June, and 1890 July.
2008-09	1122 Aug 15, 1131 Aug 31, 1531 Sep, 524 Apr 30, 2136 May, 1807 June, and 2052 July.
2009-10	399 Aug 15, 405 Aug 31, 1082 Sep, 894 Apr 30, 2692 May, 2974 June, and 1524 July.

3. For 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.

4. The 1990 level modified flows were used for the 2005-06 through 2008-09 levels with an adjustment for Grand Coulee pumping and return flow. The 2009-10 used updated 2000 level modified flows and updated Grand Coulee pumping and return flows.

CHART 1
2009-10 DDBP STUDIES
DURATION CURVES OF 30 YEARS MONTHLY HYDRO GENERATION (aMW)