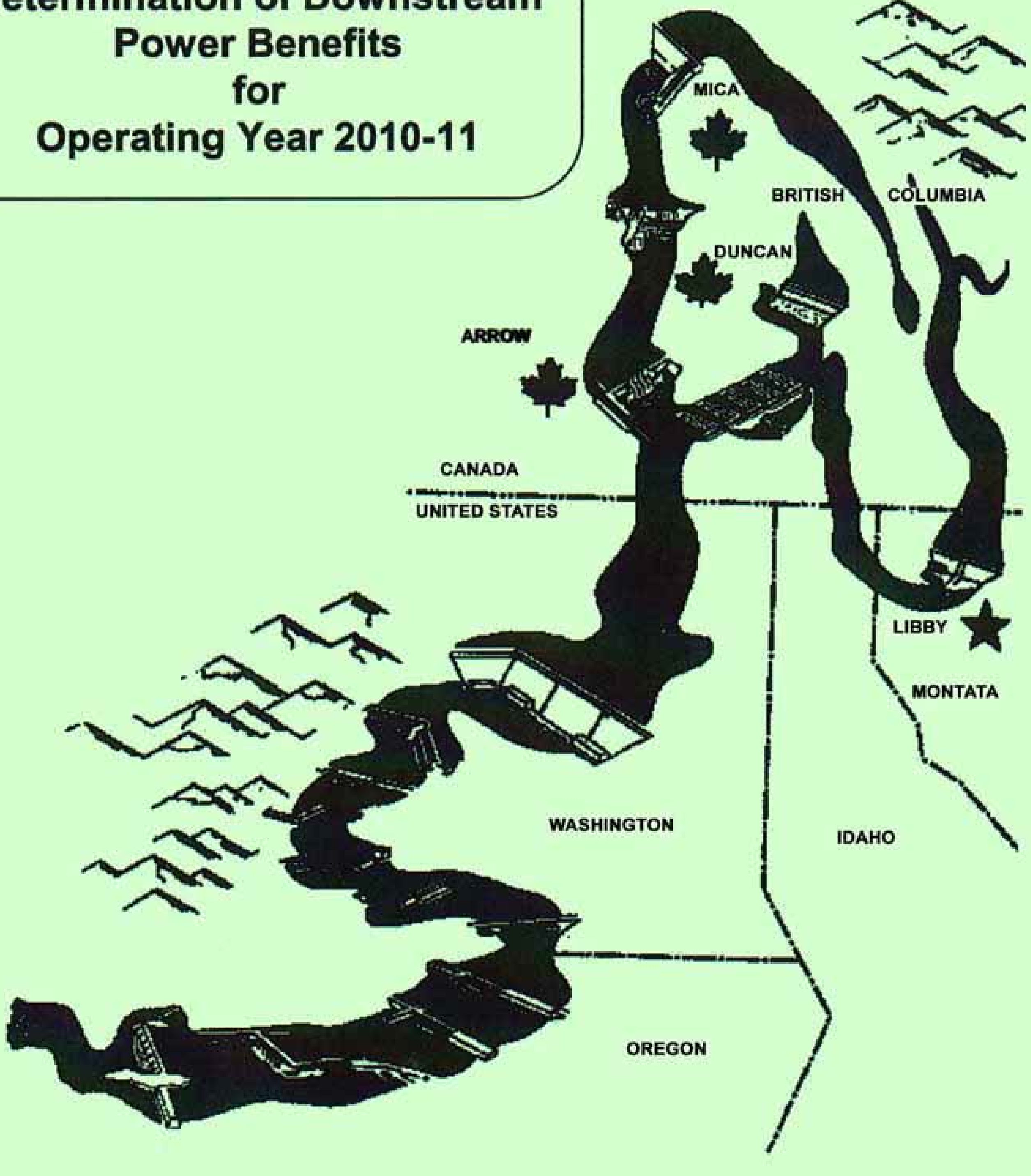
COLUMBIA RIVER TREATY
Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2010-11



Columbia River Treaty Operating Committee

January 2006

COLUMBIA RIVER TREATY ENTITY AGREEMENT ON THE ASSURED OPERATING PLAN AND DETERMINATION OF DOWNSTREAM POWER BENEFITS FOR THE 2010-11 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 2010-11" and "Columbia River Treaty Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2010-11," both dated January 2006, shall be the Assured Operating Plan and Determination of Downstream Power Benefits for the 2010-11 Operating Year.

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

Executed for the Canadian Entity this 2nd day of February, 2006.

By: ____________________
Robert G. ~~Elton~~
Chair

Executed for the United States Entity this 6th day of February, 2006.

By: ____________________
Stephen J. Wright
Chairman

By: ____________________
BG Gregg F. Martin
Member

COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

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January 2006

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 2010-11 AOP (AOP11) 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 the following changes from procedures in POP:

- Use only the first of the three Streamline Procedures, "Forecasting Loads and Resources," defined in Appendix 6 of the POP;

- Revise adjustment for Canadian critical rule curve crossovers (see subsection 3a);

- Implement the Arrow Project Operating Criteria (see subsection 4c(2)); and

- Do not adjust Variable Refill Curve Lower Limits for crossovers as defined in POP Appendix 1 (see subsection 7d).

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 (AOP11-41) 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 2010-11 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 AOP11 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[6] and including estimates of Grand Coulee pumping requirements.

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.

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 AOP11, 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 2.0 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 DDPB11, columns A and B.)

Since there is no reduction in entitlement, the Entities have determined in Section 3 of the 2010-11 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 2010-11 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 criteria for Mica and Arrow. 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). Generally, CRCs are adjusted for crossovers by the hydroregulation model as defined in Section 2.3.A of the POP. CRC crossovers occur when the second, third, or fourth year CRC's are higher than lower numbered CRC's, and past practice was for the hydro regulation model to lower the CRC2, CRC3, or CRC4 at all projects as needed to eliminate the crossover. However, for the AOP11, the procedure was revised for the Canadian projects. The new procedure adjusts Canadian projects only if the sum of Mica + Arrow + Duncan Treaty storage has a composite CRC crossover. The adjustment is made to Arrow first unless/until Arrow is empty, then the adjustment is made to Duncan. 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 Maf 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 2010-11, 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 km^3 and 4.44 km^3 (4.08 Maf 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 AOP11-41 System Regulation Study was used to develop and test the operating rules and rule curves. The System Regulation Study storage operation results for the whole of Canadian Treaty Storage for the 30-year streamflow period are shown in Table 11. The Study 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 AOP11-41 System Regulation Study will apply to the operation of Canadian Treaty Storage in the 2010-11 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 Mica, Revelstoke, and Arrow, and downstream in the USA. Under these operating criteria, outflows will be increased as required to avoid storage above the URC at each 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 excess Mica storage releases to be retained at Arrow. Based on this AOP, the probability of a combined Mica + Arrow storage release in excess of 17.39 km^3 (14.1 Maf) occurring has been judged to be negligible; however, in actual operations, should Treaty specified constraints require combined Mica + Arrow storage draft in excess of 17.39 km^3 (14.1 Maf), it is mutually agreed for the sole purpose of this AOP that such releases may occur. If such a release should occur, the target Mica operation will remain as specified in Table 1, and the excess release will be returned as soon as the operating criteria permit.

The adoption of the above described procedure for addressing total combined storage draft from Mica and Arrow in this AOP11 is not intended to set precedent for future AOPs and is subject to change in future AOPs.

(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 1,982 m^3/s (70,000 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 AOP11, and which were based on the criteria in Table 1.1(a). The minimum outflow limit for Arrow is increased from 142 m^3/s (5,000 cfs) to 283 m^3/s (10,000 cfs) for July through May, except that the minimum flow will be decreased as needed (but limited to no lower than 142 m^3/s (5,000 cfs)) to prevent the combined draft of Mica and Arrow from exceeding 17.39 km^3 (14.1 Maf).

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 AOP11 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 2010-11 DOP (DOP11) 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 DOP11. Failing agreement on updating the data and/or criteria, the DOP11 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 2010-11 Operating Year shall be guided by the DOP11.

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 2010-11."

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 2010 through

31 July 2011 period covered by this AOP, and includes transmission losses and scheduling guidelines for delivery of the Canadian Entitlement.

7. Summary of Changes from the 2009-10 AOP and Notable Assumptions

Data from the recent AOPs are compared and summarized in Table 12. An explanation of the more important changes and notable assumptions follows.

a) Loads

Loads for the AOP11 are based on Bonneville Power Administration's (BPA) 21 April 2005 Draft 2004 White Book (WB04) medium-case load forecast. The Draft WB04 regional load forecast for the AOP11 is 361 annual aMW (1.6%) less than the WB02 forecast used in the AOP10. However, because only a portion of the Utah Power & Light load is excluded in the AOP11 (explained below) the net PNWA firm load from the AOP10 to AOP11 goes down by only 235 annual aMW (1%). The Draft WB04 forecast includes reductions to Generating Public and Investor-owned entity loads. The Draft WB04 forecast of the 2011 average annual firm load is 22,293 MW, and is based on a 1.25% annual load growth from the 2010 operating year. Other load assumptions and changes include:

- The Utah Power & Light (UP&L) load in eastern Idaho that was excluded from White Book totals in the AOP10 and prior AOPs has been modified to reflect 1) the updated WB04 UP&L Idaho load forecast, 2) the exclusion of only the smaller area served by UP&L in 1964, and 3) the removal of the transfer loads to other utilities included in UP&L's service area. Annex B, paragraph 7, of the Treaty requires the area served by UP&L in 1964 to be excluded from the PNWA firm load. All of the UP&L load and import supporting it, were excluded from previous AOPs. The AOP11 will exclude 57.3% of the UP&L load in Idaho from the PNWA firm load, and all of the import from Utah will continue to be excluded, although now only the portion serving the AOP load area for UP&L will be classified as a thermal installation. The net effect of these UP&L Idaho load changes on the AOP11 Step I loads is a 125 annual aMW increase in the PNWA firm load compared to AOP10.
- The WB04 does not include transmission losses in the firm load forecast, but instead decreases all resources (including imports) by 2.67% energy and 3.20% peak to account for transmission grid and step-up transformer power losses. Transmission losses are no longer included in the White Book loads because the load forecast in most cases is for the point of delivery at the utility's connection to the grid. This procedure began with the WB99 and should have been included in the 2006-07 and later AOPs. Those AOP Step I studies did include a reduction for federal hydro generation step-up transformer losses, but not the grid losses and step-up transformer losses for some other resources. The AOP11 calculation assumes that 68% of the resources (based on federal and Mid-C hydro, large thermal, and import thermal) are measured at the grid connection and therefore should not include the estimated 0.22% step-up transformer losses. The effect on the

AOP11 Step I Study, compared to the AOP10, of including the additional transmission losses is to increase the Step I System load by 637 annual aMW.

- The average critical period load factor increased from 73.85% in AOP10 (from WB02) to 75.89% in AOP11 (from WB04). This was mainly due to a change in forecast procedure, with more collaboration on development of public and investor owned utilities loads in the WB04 and changes to the commercial loads. Excluding a smaller portion of the UP&L load in Idaho (92% load factor) also contributed to the increase in the system load factor.
- Updated irrigation pumping loads for Grand Coulee are included in the Regional Firm Load. Both these irrigation loads and the pumping amounts were obtained from the February 2005 Pacific Northwest Coordination Agreement (PNCA) data submittal from the Bureau of Reclamation that was based on the previous five-year average discharge into Banks Lake. Differences from the WB04 vary from -68 aMW in Apr2 to 48 aMW in Sept, with a net annual difference of 0.5 aMW.
- 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 2010-11 Energy Entitlement from BPA's WB04. The estimated and the computed Canadian Entitlement are shown below:

During 1 August 2010 – 31July 2011

Canadian Entitlement Return	**Energy (aMW)**		**Capacity (MW)**	
	Estimated	Computed	Estimated	Computed
Export to BC (1/2)	269.0	267.9	676.0	658.2
Retained in PNW (1/2)	269.0	267.9	676.0	658.2
Total	538.0	535.7	1352.0	1316.4

Iterative studies to update the Canadian Entitlement in the load estimate were not performed because the effect on the amount of thermal installations would not significantly affect the results of the studies.

- Compared to the AOP10, Flows-Out (exports that are mostly to the southwest) increased by 12 annual aMW, and Flows-In (imports) decreased by 146 annual 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 an 80 annual aMW increase 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 and later 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 based on the sum of WB04 thermal resources, 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 included in the 2010-11 study. The total Thermal Installations increased by 478 annual aMW compared to the AOP10, mainly due to the impact of additional transmission losses.

c) Hydro Project Modified Streamflows

The base unregulated streamflows used in the System Regulation Studies were 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. Forecasts of Grand Coulee pumping estimates were updated from the February 2005 PNCA data submittal, but the Grand Coulee return flows were not updated, because return flow is assumed in the 2000 Modified Streamflow record and the update volumes are minimal.

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. Other changes and notable assumptions include:

- The agreed allocation of flood control space in Mica and Arrow is 5.03 and 4.44 km^3 (4.08 and 3.6 Maf), respectively. The URC data was the same used since the AOP07. 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 procedure for adjusting Canadian CRCs for crossovers was revised as described in subsection 3a.
- The past practice of raising the 80 Maf VRCLL to the CRC1 was not used in the AOP11 studies after it was determined that it adversely affected optimum power generation.
- Brownlee's critical rule curves and operating rule curves were updated for AOP 11 to approximate the historic operation of Brownlee during 1975 through 1985 (prior to modern fishery constraints), except for modifications needed by the 1988 and 1996 Entity Agreements that allow starting the critical period full and ending the critical period empty. In the Step 1 studies,

the initial storage at Brownlee was set to 477.8 ksfd (1555.4 ft), which is the CRC1 and ECC in July through August.

- Distribution factors for Libby in May and June had minor updates.

- The VarQ flood control rule curves are used for Hungry Horse, but not Libby. This has been the same since the AOP07.

e) <u>Other Hydro Project Operating Procedures and Constraints</u>

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. Other changes and notable assumptions include:

- Brownlee minimum flow requirements were 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.

- Dworshak is operated to a minimum flow or flood control October through May, but met a target operation June through September to obtain uniform outflows July through August. Dworshak refills to higher levels as defined in the February 2005 PNCA submittal. Initial storage in the 2011 study is 779.3 (1573.2 ft) ksfd while in the 2010 study, 393.8 (1519.7 ft) ksfd is used.

- The amount of spill and timing of spill at Lower Granite, Little Goose, and Lower Monumental vary depending on new spill triggers based on seasonal average regulated outflows at Lower Granite.

- Grand Coulee is full through August 31 at the beginning of the critical period to avoid a surplus.

- As in AOP10, 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. For AOP11, Pacificorp has also withdrawn Swift #1, Merwin and Yale projects from PNCA planning and these, too, are first-coded for the 60 year operation.

- The Ross/Gorge spreadsheet is updated for minimum flows to Gorge and minimum content to Ross.

- Upper and Lower Baker storage vs elevation tables are updated.

- Cabinet Gorge generation vs discharge and spill vs discharge tables are updated.

- Rock Island generation vs discharge table is updated.
- Hydro-independent projects are not yet 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 11-41," dated 12 December 2005.

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
2010-11 ASSURED OPERATING PLAN

	Target Operation			Target Operation Limits		
Month	End of Previous Month Arrow Storage Content (ksfd)	Month Average 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	3,170 - FULL	-	3,439.2	-	34,000	15,000
	2,200 - 3,170	25,000	-	0	-	15,000
	0 - 2,200	32,000	-	0	-	15,000
August 16-31	3,220 - FULL	-	3,529.2	-	34,000	15,000
	2,260 - 3,220	25,000	-	0	-	15,000
	0 - 2,260	31,000	-	0	-	15,000
September	3,490 - FULL	-	3,529.2	-	34,000	10,000
	3,370 - 3,490	24,000	-	0	-	10,000
	1,100 - 3,370	27,000	-	0	-	10,000
	0 - 1,100	31,000	-	0	-	10,000
October	3,370 - FULL	-	3,428.4	-	34,000	10,000
	2,910 - 3,370	19,000	-	0	-	10,000
	500 - 2,910	22,000	-	0	-	10,000
	0 - 500	32,000	-	0	-	10,000
November	3,350 - FULL	21,000	-	0	-	10,000
	3,040 - 3,350	19,000	-	0	-	10,000
	390 - 3,040	25,000	-	0	-	10,000
	0 - 390	32,000	-	0	-	10,000
December	2,940 - FULL	25,000	-	254.1	-	10,000
	2,285 - 2,940	22,000	-	254.1	-	10,000
	400 - 2,285	27,000	-	254.1	-	10,000
	0 - 400	32,000	-	254.1	-	10,000
January	2,490 - FULL	27,000	-	204.1	-	12,000
	2,310 - 2,490	28,000	-	204.1	-	12,000
	1,400 - 2,310	26,000	-	204.1	-	12,000
	0 - 1,400	29,000	-	204.1	-	12,000
February	1,500 - FULL	21,000	-	0	-	12,000
	1,170 - 1,500	26,000	-	0	-	12,000
	500 - 1,170	23,000	-	0	-	12,000
	0 - 500	26,000	-	0	-	12,000
March	830 - FULL	21,000	-	0	-	12,000
	800 - 830	23,000	-	0	-	12,000
	500 - 800	19,000	-	0	-	12,000
	0 - 500	24,000	-	0	-	12,000
April 1-15	890 - FULL	22,000	-	0	-	12,000
	600 - 890	10,000	-	0	-	12,000
	60 - 600	17,000	-	0	-	12,000
	0 - 60	21,000	-	0	-	12,000
April 16-30	260 - FULL	10,000	-	0	-	10,000
	120 - 260	14,000	-	0	-	10,000
	20 - 120	10,000	-	0	-	10,000
	0 - 20	21,000	-	0	-	10,000
May	270 - FULL	8,000	-	0	-	8,000
	70 - 270	10,000	-	0	-	8,000
	0 - 70	8,000	-	0	-	8,000
June	850 - FULL	8,000	-	0	-	8,000
	660 - 850	18,000	-	0	-	8,000
	0 - 660	10,000	-	0	-	8,000
July	3,180 - FULL	-	3,467.2	-	34,000	10,000
	2,470 - 3,180	-	3436.2	-	34,000	10,000
	1,430 - 2,470	20,000	-	0		10,000
	0 - 1,430	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
2010-11 ASSURED OPERATING PLAN

Period	Volume Runoff Period	The Dalles Volume Runoff (Maf)	Maximum Storage Limit 1/ 2/ (ksfd)	Maximum Outflow Limit 3/ (cfs)	Minimum Outflow Limit 4/ (cfs)
January	-		URC	70,000	10,000
February	1 Feb - 31 Jul	≤ 70	URC	60,000	10,000
		>70 to <80	URC to 1800		
		≥ 80	1800		
March	1 Mar - 31 Jul	≤ 65	URC		10,000
		>65 to <75	URC to 900		
		≥ 75	900		
April 15	1 Apr - 31 Jul	≤ 61	URC		10,000
		>61 to <70	URC to 900		
		≥ 70	900		
April 30	1 Apr - 31 Jul	≤ 61	URC		10,000
		>61 to <70	URC to 1000		
		≥ 70	1000		
May	1 May - 31 Jul	≤ 68	URC		10,000
		>68 to <70	URC to 1800		
		≥ 70	1800		
June	1 Jun - 31 Jul	≤ 33	URC		
		>33 to <35	URC to 3300		
		≥ 35	3300		
July - December			URC		10,000

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.

4/ The Minimum Average Monthly Outflow Limit is an operating limit and may be reduced to as low as 5,000 cfs (Treaty minimum) to avoid drafting Mica+Arrow storage beyond 14.1 Maf. There is no operating minimum flow limit for June.

TABLE 1.1b
(English Units)
ARROW PROJECT OPERATING CRITERIA
FOR 2010-11 ASSURED OPERATING PLAN

Maximum Average Monthly Flow Limits (cfs)

Period	JAN	FEB
Flow Limit	70,000	60,000

Minimum Average Monthly Flow Limits (cfs)

Period	JUL-MAY
Flow Limit	10,000

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
2010-11 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 DOP11 will apply these distribution factors to the monthly volume forecast at The Dalles for computing the Month-July runoff volumes required by the APOC. 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 2010-11 ASSURED OPERATING PLAN
STUDY RESULTS

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

	Study No. 11-41	Study No. 11-11	Net Gain	Weight	Value
1. Firm Energy Capability (aMW)					
U.S. System 1/	12106.4	12106.7	-0.3		
Canada 2/, 3/	2920.5	2886.2	34.4		
Total	15026.9	14992.9	34.0	3	102.0
2. Dependable Peaking Capacity (MW)					
U.S. System 4/	30341.4	30360.5	-19.1		
Canada 2/, 5/	5659.9	5616.1	43.8		
Total	36001.3	35976.6	24.7	1	24.7
3. Average Annual Usable Secondary Energy (aMW)					
U.S. System 6/	3081.0	3065.0	16.0		
Canada 2/, 7/	254.4	275.2	-20.8		
Total	3335.4	3340.2	-4.8	2	-9.5
			Net Change in Value =		117.2

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)
2010 - 11 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	3529.2	3523.1	3495.5	3376.2	2970.9	2226.8	1447.2	689.1	413.3	165.9	166.7	462.2	2096.3	3059.6
1929-30	3394.7	3490.1	3364.4	2496.5	2008.8	1481.5	538.3	183.3	0.0	0.0	201.4	520.0	1227.9	2615.9
1930-31	2977.2	3284.6	3292.3	2529.1	2131.9	1318.7	791.9	114.3	0.0	0.0	0.0	225.7	955.5	2109.7
1931-32	2030.7	1867.8	1226.3	1072.2	641.0	2.7	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	3579.6	3570.7	3290.1	3001.0	2741.2	2441.8	1459.3	753.8	677.1	753.7	709.8	1637.0	3186.0	3539.2
1929-30	3543.8	3527.1	3044.0	2981.9	2072.9	1517.2	521.9	172.2	0.9	2.6	368.3	1323.1	2601.0	3419.9
1930-31	3492.2	3413.6	2917.8	2816.3	2007.7	1164.8	339.4	98.7	7.5	4.8	22.5	956.1	1773.8	1688.1
1931-32	1746.5	1864.4	1716.5	1137.7	846.1	271.6	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	705.8	700.3	672.2	652.1	589.3	417.4	336.3	250.0	170.0	128.6	139.9	257.4	532.2	634.4
1929-30	674.3	638.1	630.6	615.6	594.4	452.5	246.0	130.3	0.6	0.7	33.1	148.1	367.7	538.7
1930-31	604.1	597.9	642.8	662.2	640.3	415.7	188.2	59.4	0.0	0.0	1.6	157.2	113.3	154.7
1931-32	199.1	128.5	146.6	132.2	92.8	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	7814.6	7794.1	7457.8	7029.3	6301.4	5086.0	3242.8	1692.9	1260.4	1048.2	1016.4	2356.6	5814.5	7233.2
1929-30	7612.8	7655.3	7039.0	6094.0	4676.1	3451.2	1306.2	485.8	1.5	3.3	602.8	1991.2	4196.6	6574.5
1930-31	7073.5	7296.1	6852.9	6007.6	4779.9	2899.2	1319.5	272.4	7.5	4.8	24.1	1339.0	2842.6	3952.5
1931-32	3976.3	3860.7	3089.4	2342.1	1579.9	274.4	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Note: These rule curves are input to the AOP 2011 Step 1 study.
They will be adjusted to eliminate any Canadian composite crossovers according to 3 a) of the AOP document.

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
2010 - 11 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	0.0	531.5	1133.9	1312.4	1377.7	1394.2	1389.0	1377.5	1384.3	1409.3	1472.5	2232.7	3268.8	3529.2
VARIABLE REFILL CURVES (KSFD)														
1928-29							2379.1	2263.5	2224.2	2229.8	2270.3	2715.7	3117.8	3529.2
1929-30							1356.8	1201.9	1153.1	1176.5	1332.6	2109.6	2834.0	*
1930-31							1614.6	1468.7	1415.3	1417.2	1507.1	2128.5	2908.7	*
1931-32							620.7	482.0	435.3	437.8	554.8	1287.3	2572.1	*
1932-33							527.2	424.0	394.5	395.0	472.2	1186.2	2409.5	*
1933-34							11.9	0.0	0.0	0.0	0.0	932.3	2661.1	*
1934-35							898.9	776.9	759.7	780.2	849.9	1494.4	2528.4	*
1935-36							739.5	618.0	589.4	589.5	684.2	1498.8	2811.2	*
1936-37							2365.8	2229.6	2175.5	2170.1	2258.8	2727.9	3149.4	*
1937-38							899.6	777.7	730.9	738.0	830.7	1511.5	2663.9	*
1938-39							1332.5	1255.0	1215.5	1243.2	1353.9	2064.9	3106.4	*
1939-40							1120.2	1006.0	983.9	1005.5	1134.6	1867.6	2869.3	*
1940-41							1799.7	1674.4	1640.4	1661.7	1838.2	2506.9	3131.5	*
1941-42							1408.8	1287.3	1245.2	1243.2	1318.9	1921.9	2860.9	*
1942-43							1536.6	1392.4	1347.3	1345.1	1497.1	2139.0	2902.1	*
1943-44							2471.4	2319.5	2279.1	2282.8	2351.0	2837.5	3289.0	*
1944-45							2260.6	2145.7	2119.0	2133.4	2182.6	2625.7	3153.4	*
1945-46							320.9	168.7	120.2	110.4	201.6	985.5	2568.0	*
1946-47							434.7	336.2	316.5	328.3	444.7	1246.2	2636.2	*
1947-48							383.6	264.4	229.7	215.4	295.2	1041.7	2522.9	*
1948-49							2080.1	1935.5	1873.8	1871.3	1948.3	2417.6	3294.5	*
1949-50							739.0	580.5	522.0	512.5	596.9	1262.9	2334.3	*
1950-51							730.3	619.4	592.9	601.2	714.7	1382.0	2695.7	*
1951-52							1137.1	983.5	931.6	916.5	997.8	1677.4	2843.1	*
1952-53							1418.3	1282.6	1240.2	1237.9	1297.3	1832.6	2810.0	*
1953-54							294.1	170.6	152.9	156.6	240.1	957.9	2306.4	*
1954-55							1053.9	946.4	920.4	930.7	1016.9	1603.7	2500.8	*
1955-56							602.3	477.2	430.5	423.6	512.0	1280.0	2610.3	*
1956-57							770.9	638.5	606.5	611.7	700.7	1366.1	2940.9	*
1957-58							604.6	485.1	459.6	470.2	575.2	1262.9	2703.4	*
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	3543	25599	48094
VARIABLE REFILL CURVES						80 MAF	3000	3000	3000	3000	3000	3000	29000	31000
(BY VOLUME RUNOFF AT THE DALLES						95 MAF	3000	3000	3000	3000	3000	3000	18000	24000
						110 MAF	3000	3000	3000	3000	3000	3000	18000	24000
VARIABLE REFILL CURVE LOWER LIMITS (						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)							325.1	53.7	0.0	0.0				

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
2010 - 11 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	785.1	1609.7	1672.6	1692.2	1742.9	1851.7	2910.4	3414.6	3579.6
VARIABLE REFILL CURVES (KSFD)														
1928-29							2937.4	2793.4	2656.4	2612.1	2731.9	3230.5	3346.6	3579.6
1929-30							1348.0	1316.4	1319.3	1335.5	1598.0	2737.4	3420.0	*
1930-31							1760.8	1615.5	1499.1	1487.6	1692.5	2572.3	3365.6	*
1931-32							4.0	0.0	17.5	5.1	8.2	941.8	2743.3	*
1932-33							2.3	2.0	17.2	0.8	5.3	906.9	2710.3	*
1933-34							2.0	0.0	17.2	0.0	4.7	900.0	3013.6	*
1934-35							892.6	899.5	968.0	1003.1	1180.6	2257.7	3213.3	*
1935-36							976.8	886.9	800.4	778.8	939.4	2271.2	3474.7	*
1936-37							3245.8	3057.5	2910.1	2837.3	2978.8	3406.1	3412.3	*
1937-38							3.2	0.0	17.4	3.1	6.8	939.8	2889.1	*
1938-39							1540.5	1452.4	1393.6	1379.2	1614.0	2664.3	3517.9	*
1939-40							1280.4	1251.8	1260.2	1358.9	1629.8	2643.5	3469.7	*
1940-41							2394.3	2298.6	2220.0	2331.0	2761.0	3517.5	3579.6	*
1941-42							2093.4	2054.4	2017.8	2001.4	2183.6	3016.0	*	*
1942-43							705.1	546.2	472.1	440.9	665.0	1744.1	3249.1	*
1943-44							3579.6	3579.6	3498.2	3429.0	3579.6	3579.6	3579.6	*
1944-45							3017.0	2927.7	2828.7	2812.9	2928.4	3325.0	3560.0	*
1945-46							2.0	0.0	17.2	0.0	4.7	900.0	2723.8	*
1946-47							4.2	0.0	17.5	5.5	8.5	966.9	2924.4	*
1947-48							2.0	0.0	17.2	0.0	4.7	900.0	2750.3	*
1948-49							1194.8	1068.3	979.1	946.6	1171.8	1941.5	3415.4	*
1949-50							2.0	0.0	17.2	0.0	4.7	900.0	2703.8	*
1950-51							*	*	*	*	*	*	2894.1	*
1951-52							*	*	*	*	*	*	2865.5	*
1952-53							109.5	60.6	33.3	28.1	172.6	1140.1	2962.7	*
1953-54							2.0	0.0	17.2	0.0	4.7	900.0	2703.8	*
1954-55							524.1	530.8	529.6	516.0	721.2	1749.2	2904.7	*
1955-56							2.0	0.0	17.2	0.0	4.7	900.0	2753.9	*
1956-57							*	*	*	*	*	*	2885.3	*
1957-58							3.5	0.0	17.4	3.9	7.4	932.0	2862.5	*
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	6000	7000	7000	9000	10395	63090	75081
VARIABLE REFILL CURVES						80 MAF	5000	5000	5000	5000	5000	5000	55000	58000
(BY VOLUME RUNOFF AT THE DALLES						95 MAF	5000	5000	5000	5000	5000	5000	43000	57000
						110 MAF	5000	5000	5000	5000	5000	5000	5000	38000
VARIABLE REFILL CURVE LOWER LIMITS (						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)							204.1	0.1	0.1	0.0				

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
2010 - 11 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	1.5	61.9	128.2	158.9	176.4	187.6	197.7	206.9	221.0	231.9	247.4	403.3	555.7	705.8
VARIABLE REFILL CURVES (KSFD)														
1928-29							341.4	337.4	334.4	332.9	349.6	406.8	598.4	705.8
1929-30							339.8	335.4	332.1	330.4	354.7	427.3	*	*
1930-31							284.3	281.2	281.5	284.7	307.6	376.8	*	*
1931-32							9.3	3.0	2.9	0.0	7.7	151.2	464.3	*
1932-33							6.5	0.5	0.7	*	3.7	108.1	446.6	*
1933-34							5.9	0.0	0.3	*	32.8	230.7	534.5	*
1934-35							58.3	22.9	25.6	27.6	52.0	226.9	537.0	*
1935-36							76.1	25.3	30.4	24.4	57.5	239.9	545.2	*
1936-37							277.2	272.3	271.2	269.8	290.9	361.8	598.4	*
1937-38							8.0	1.8	1.9	5.5	35.8	200.3	492.1	*
1938-39							164.6	111.9	113.5	117.2	149.1	304.3	586.4	*
1939-40							166.5	104.6	113.9	127.2	161.7	305.7	587.3	*
1940-41							193.2	197.7	202.8	217.9	263.5	366.1	598.4	*
1941-42							124.0	130.9	135.9	139.8	169.2	297.9	538.3	*
1942-43							116.7	116.3	119.9	122.3	161.2	308.7	520.3	*
1943-44							347.5	348.2	349.7	350.2	374.0	434.0	598.4	*
1944-45							250.1	251.0	253.7	254.7	273.1	352.5	579.3	*
1945-46							5.9	0.0	0.3	0.0	2.9	105.5	461.6	*
1946-47							9.6	3.2	3.2	*	8.1	136.7	471.6	*
1947-48							5.9	0.0	0.3	*	2.9	153.7	485.6	*
1948-49							177.3	174.0	174.2	173.6	199.0	327.4	586.7	*
1949-50							5.9	0.0	0.3	0.0	2.9	157.5	444.6	*
1950-51							*	*	*	*	*	121.7	453.9	*
1951-52							7.1	6.2	12.5	13.1	39.2	215.1	503.5	*
1952-53							10.2	6.7	11.0	13.2	36.2	190.0	467.5	*
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	454.7	*
1956-57							*	*	*	*	*	152.3	521.3	*
1957-58							8.5	2.3	2.3	*	6.6	117.5	474.7	*
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	141	2951	2479
VARIABLE REFILL CURVES						80 MAF	100	100	100	100	100	1400	1500	1500
(BY VOLUME RUNOFF AT THE DALLES						95 MAF	100	100	100	100	100	100	600	1100
						110 MAF	100	100	100	100	100	100	600	1000
VARIABLE REFILL CURVE LOWER LIMITS (						80 MAF	190.5	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)							113.3	27.9	0.0	0.0				

TABLE 7
(English Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2010 - 11 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	3529.2	3529.2	3529.2	3428.4	3428.4	3331.6	3238.8	3154.6	3061.8	3061.8	3061.8	3178.6	3529.2	3529.2
1929-30	"	"	"	"	"	"	3182.1	3046.6	2897.2	2897.2	2897.2	3055.2	"	"
1930-31	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3381.0	"	"
1931-32	"	"	"	"	"	"	2699.3	2104.4	1472.2	1472.2	1472.2	2445.1	"	"
1932-33	"	"	"	"	"	"	2691.3	2112.5	"	"	"	2074.9	3093.1	"
1933-34	"	"	"	"	"	"	"	"	"	"	1780.7	2706.4	3529.2	"
1934-35	"	"	"	"	"	"	"	"	"	"	1472.2	2046.1	3093.1	"
1935-36	"	"	"	"	"	"	2699.3	2104.4	"	"	"	2373.1	3529.2	"
1936-37	"	"	"	"	"	"	3136.9	2960.5	2765.8	2765.8	2765.8	3262.0	"	"
1937-38	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	2130.4	3183.6	"
1938-39	"	"	"	"	"	"	2862.1	2438.3	1968.8	1968.8	1968.8	2786.5	3529.2	"
1939-40	"	"	"	"	"	"	3009.7	2708.9	2387.0	2387.0	2387.0	2958.1	"	"
1940-41	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3381.0	"	"
1941-42	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	2212.7	"	"
1942-43	"	"	"	"	"	"	"	"	"	"	1677.9	1883.6	2706.4	"
1943-44	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3381.0	3529.2	"
1944-45	"	"	"	"	"	"	2836.8	2390.0	1895.1	1895.1	1895.1	2506.3	3333.1	"
1945-46	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	2426.6	3529.2	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	2383.4	"	"
1947-48	"	"	"	"	"	"	2699.3	2104.4	"	"	"	2439.0	"	"
1948-49	"	"	"	"	"	"	2691.3	2112.5	"	"	"	2661.1	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	1556.5	2451.3	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	1749.9	3335.9	"
1951-52	"	"	"	"	"	"	2699.3	2104.4	"	"	"	2099.6	3076.7	"
1952-53	"	"	"	"	"	"	2691.3	2112.5	"	"	"	1846.6	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	1967.9	2183.9	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	1988.5	3245.4	"
1955-56	"	"	"	"	"	"	2699.3	2104.4	"	"	1554.5	2295.0	3117.8	"
1956-57	"	"	"	"	"	"	2691.3	2112.5	"	"	1472.2	2786.6	3529.2	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	2459.6	"	"

TABLE 8
(English Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2010 - 11 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)
2010 - 11 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)
2010 - 11 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7794.1	7457.8	7029.3	6301.4	5086.0	3393.2	3300.1	3297.5	3384.1	3571.6	5546.4	7020.1	7814.6
1929-30	"	"	"	"	"	"	3041.1	2768.3	2693.4	2743.9	3178.0	5250.3	6804.3	"
1930-31	"	"	"	"	"	"	3341.2	3243.0	3104.4	3128.8	3412.4	5077.6	6829.8	"
1931-32	"	"	"	"	"	"	938.1	510.0	455.7	442.9	570.7	2380.3	5779.7	"
1932-33	"	"	"	"	"	"	844.6	452.0	412.5	395.8	481.2	2201.2	5566.5	"
1933-34	"	"	"	"	"	"	642.5	81.7	17.5	0.0	37.5	2063.0	6209.2	"
1934-35	"	"	"	"	"	"	1904.8	1704.3	1753.3	1810.9	2082.5	3939.3	6211.3	"
1935-36	"	"	"	"	"	"	1829.6	1532.8	1420.2	1392.7	1681.1	4009.9	6771.0	"
1936-37	"	"	"	"	"	"	3334.1	3300.1	3297.5	3384.1	3571.6	5504.9	7108.5	"
1937-38	"	"	"	"	"	"	1217.0	805.7	750.2	746.6	873.3	2651.6	6045.1	"
1938-39	"	"	"	"	"	"	3037.6	2799.6	2701.3	2714.6	3060.1	5033.5	7076.7	"
1939-40	"	"	"	"	"	"	2567.1	2362.4	2358.0	2479.3	2879.3	4816.8	6839.6	"
1940-41	"	"	"	"	"	"	3250.1	3247.8	3278.6	3354.3	3526.3	5487.3	7070.6	"
1941-42	"	"	"	"	"	"	3142.5	3090.8	3073.3	3125.9	3252.7	4637.8	6813.8	"
1942-43	"	"	"	"	"	"	2269.0	2040.0	1939.3	1908.3	2298.7	3916.1	5965.9	"
1943-44	"	"	"	"	"	"	3393.2	3300.1	3297.5	3384.1	3571.6	5546.4	7239.1	"
1944-45	"	"	"	"	"	"	3307.0	3300.1	3297.5	3384.1	3571.6	5259.6	7115.2	"
1945-46	"	"	"	"	"	"	642.5	196.7	137.7	110.4	209.2	1991.0	5753.4	"
1946-47	"	"	"	"	"	"	752.1	364.2	337.2	333.8	461.3	2349.8	6032.2	"
1947-48	"	"	"	"	"	"	701.0	292.4	247.2	215.4	302.8	2095.4	5758.8	"
1948-49	"	"	"	"	"	"	2819.3	2619.8	2537.6	2529.5	2843.0	4501.6	7239.1	"
1949-50	"	"	"	"	"	"	1056.4	608.5	539.5	512.5	604.5	2320.4	5407.4	"
1950-51	"	"	"	"	"	"	1047.7	647.4	610.4	601.2	722.3	2403.7	6043.7	"
1951-52	"	"	"	"	"	"	1454.5	1011.5	961.3	929.6	1041.7	2792.5	6091.7	"
1952-53	"	"	"	"	"	"	1735.7	1371.1	1284.5	1279.2	1506.1	3162.7	6240.2	"
1953-54	"	"	"	"	"	"	642.5	198.6	170.4	156.6	247.7	1963.4	5021.1	"
1954-55	"	"	"	"	"	"	1691.3	1505.1	1463.7	1446.7	1765.4	3507.4	5894.3	"
1955-56	"	"	"	"	"	"	919.7	505.2	448.0	423.6	519.6	2285.5	5818.9	"
1956-57	"	"	"	"	"	"	1088.3	666.5	624.0	611.7	708.3	2418.4	6347.5	"
1957-58	"	"	"	"	"	"	922.0	513.1	479.3	474.1	589.2	2312.4	6040.6	"

TABLE 11
(English Units)
COMPOSITE END STORAGE
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2010 - 11 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7794.1	7457.8	7029.3	6301.4	5086.0	3242.8	1692.9	1260.4	1048.2	1016.4	2356.6	5814.5	7233.2
1929-30	7612.8	7655.3	7039.0	6093.9	4676.1	3451.2	1306.2	485.8	1.5	3.3	602.8	1991.2	4196.6	6574.5
1930-31	7073.5	7296.1	6852.9	6007.6	4779.9	2899.2	1319.5	272.4	7.5	4.8	24.1	1339.0	2842.6	3952.1
1931-32	3976.0	3860.4	3089.2	2341.9	1579.6	274.4	3.7	0.0	1.5	178.4	381.4	2075.4	5715.7	7656.5
1932-33	7813.1	7794.1	7027.1	6302.4	6198.7	5086.0	2981.3	1349.4	412.4	395.8	481.2	2201.2	5566.4	7721.6
1933-34	7814.6	7794.1	7457.8	7029.3	6301.4	5124.2	3145.2	1528.1	745.9	597.0	1248.6	2865.9	4985.7	6522.4
1934-35	6905.3	7062.0	6399.3	5709.7	5877.2	4868.0	2773.3	1704.3	1032.0	899.8	962.6	2678.7	5573.7	7752.6
1935-36	7814.6	7768.6	7364.3	6634.8	5508.0	4000.5	1902.3	1197.2	1077.8	924.4	1161.5	3945.4	6763.2	7752.6
1936-37	7814.6	7723.5	7182.6	6318.0	4941.2	3427.9	1342.9	554.3	1.5	0.0	20.1	1356.3	4380.0	6143.1
1937-38	6185.9	6055.1	5347.9	4725.8	4418.7	3609.2	1481.1	805.7	750.2	649.9	784.6	2403.0	5767.2	7749.6
1938-39	7726.8	7652.6	7270.5	6656.3	5759.1	4704.0	3059.0	2542.3	1415.2	1421.7	1556.3	4245.3	6191.2	7752.6
1939-40	7814.6	7744.8	7222.9	6585.8	5684.6	4796.0	2676.6	2362.4	1882.5	2041.7	2382.2	4586.5	6376.3	7232.9
1940-41	7509.6	7534.2	7076.9	6807.9	5861.9	4696.2	3055.2	2552.3	2287.7	2442.0	2696.1	3854.5	4682.0	5910.2
1941-42	6123.0	6174.4	6088.2	6479.5	6301.4	5094.0	3211.4	2680.4	1228.2	1039.8	1158.8	2878.0	5575.9	7615.9
1942-43	7801.5	7794.1	7359.9	6667.6	6061.4	5086.0	2866.4	2040.0	1190.9	1022.3	1264.3	2470.6	4611.6	7314.6
1943-44	7724.6	7794.1	7421.1	6974.8	6178.8	5070.7	3278.2	1948.1	1248.2	1121.0	1131.2	1989.6	3470.5	4427.8
1944-45	4636.4	4582.5	3896.0	3385.1	2633.6	1190.7	593.8	184.6	0.7	0.0	4.2	1677.1	4642.1	6347.0
1945-46	6357.6	6241.3	5534.7	4935.1	4276.7	3246.6	1056.6	196.7	100.6	110.4	209.2	1991.0	5733.3	7721.6
1946-47	7814.6	7794.1	7457.8	7019.4	6301.4	5086.0	2898.5	1269.2	337.2	337.0	461.3	2349.8	6013.8	7721.6
1947-48	7785.3	7763.4	7457.8	7029.3	6301.4	5086.0	2944.7	1216.8	464.7	215.4	302.8	2095.4	5758.8	7806.8
1948-49	7814.6	7794.1	7457.8	7029.3	6301.4	5086.0	2900.9	2619.8	1590.6	1333.8	1445.0	3988.2	6081.8	7013.6
1949-50	7414.2	7529.4	7007.1	6279.1	6049.5	5086.0	2896.8	1240.4	539.5	512.5	604.5	1939.3	4994.8	7721.6
1950-51	7814.6	7794.1	7457.8	7029.3	6301.4	5086.0	3066.7	1421.5	675.6	666.7	784.9	2403.7	5404.5	7721.6
1951-52	7814.6	7794.1	7457.8	7029.3	6301.4	5086.0	2898.0	1196.1	961.3	929.6	1041.7	2792.5	5808.9	7691.3
1952-53	7814.6	7763.1	7313.4	6583.0	5476.8	4209.8	2039.1	1371.1	1050.1	913.2	960.0	2459.9	5471.6	7521.6
1953-54	7724.6	7794.1	7457.8	7029.3	6301.4	5086.0	2957.3	1409.8	623.1	358.9	247.7	1963.4	5012.0	7814.6
1954-55	7814.6	7794.1	7457.8	7029.3	6301.4	5086.0	3005.2	1505.1	1410.7	1435.7	1063.3	2120.8	5894.3	7721.6
1955-56	7814.6	7794.1	7457.8	7029.3	6301.4	5086.0	3042.1	1284.8	448.0	423.9	519.6	2285.5	5818.9	7721.6
1956-57	7776.9	7794.1	7457.8	7029.3	6301.4	5086.0	2918.2	1282.7	624.0	611.7	708.3	2418.4	5973.7	7120.8
1957-58	7453.2	7526.6	7006.1	6511.2	5647.2	4730.1	2591.7	1008.1	479.3	474.1	589.2	2312.4	6040.6	7191.4

TABLE 12
(English Units)
COMPARISON OF
RECENT ASSURED OPERATING PLAN STUDIES

	2003-04 2004-05 1/	2005-06	2006-07 through 2008-09 2/	2009-10	2010-11
MICA TARGET OPERATION					
(ksfd[xxxx.x] or cfs [xxxxx])					
AUG 15	3499.2	3499.1	3454.2	3454.2	3439.2
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	3524.1	FULL	FULL	FULL
OCT	3374.1	3344.1	3428.4	3428.4	3428.4
NOV	20000	23000	20000	22000	21000
DEC	23000	25000	25000	25000	25000
JAN	25000	26000	24000	23000	27000
FEB	21000	22000	21000	20000	21000
MAR	19000	20000	18000	17000	21000
APR 15	204.1	16000	18000	18000	22000
APR 30	15000	13000	12000	11000	10000
MAY	10000	10000	10000	10000	8000
JUN	10000	10000	10000	10000	8000
JUL	3449.2	3449.1	3379.2	3436.2	3467.2
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (ksfd)					
1928 AUG 31	7808.9	7678.3	7786.1	7811.6	7794.1
1928 DEC	5213.8	4938.9	5133.8	5110.5	5086.0
1929 APR15	1598.5	927.1	839.3	671.5	1048.2
1929 JUL	7280.7	7222	7147.7	7168.9	7233.2
COMPOSITE CANADIAN TREATY STORAGE CONTENT (ksfd)					
60-Yr Average					
AUG 31	7415.0	7238.3	7360.7	7455.5	7438.0
DEC	4759.5	4437.3	4634.9	4640.3	4612.9
APR15	1097.7	1085.8	1178.5	877.8	842.6
JUL	7262.0	7215.5	7193.7	7277.6	7268.9
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-1.2	-0.1	-0.2	-0.3	-0.3
U.S. Dependable Peaking Capacity	16.0	-51.0	-21.0	-2.7	-19.1
U.S. Average Annual Usable Secondary Energy	12.9	10.5	0.3	13.8	16.0
BCH Firm Energy	43.1	97.7	90.3	50.2	34.4
BCH Dependable Peaking Capacity	8.0	2.0	11.0	44.9	43.8
BCH Average Annual Usable Secondary Energy	-24.3	-55.7	-29.3	-28.2	-20.8
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	10439	11097	11137	11138	11138
AUG 31	10435	11125	11165	11166	11167
SEP	10101	10809	10849	10850	11025
OCT	10186	9742	9782	9783	9958
NOV	11807	10817	11157	11157	11333
DEC	13377	12853	13192	13193	13369
JAN	13122	12735	13075	13076	13076
FEB	12240	11561	11901	11901	11902
MAR	11175	11275	11315	11316	10967
APR 15	10541	10550	10589	10590	10241
APR 30	13065	14061	12822	12823	12475
MAY	13752	14729	13491	13491	13493
JUN	13114	14039	14079	14079	14080
JUL	12079	12383	12723	12724	12725
ANNUAL AVERAGE	11933	12034	12037	12038	12039

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
2010-11 ASSURED OPERATING PLAN

		Target Operation		Target Operation Limits		
Month	End of Previous Month **Arrow** Storage Content (hm³)	Month Average Outflow (m³/s)	End-of-Month Treaty Storage Content 1/ (hm³)	Minimum Treaty Storage Content 2/ (hm³)	Maximum Outflow 1/ (m³/s)	Minimum Outflow (m³/s)
August 1-15	7,755.7 - FULL	-	8,414.3	-	962.77	424.75
	5,382.5 - 7,755.7	707.92	-	0.0	-	424.75
	0.0 - 5,382.5	906.14	-	0.0	-	424.75
August 16-31	7,878.1 - FULL	-	8,634.5	-	962.77	424.75
	5,529.3 - 7,878.1	707.92	-	0.0	-	424.75
	0.0 - 5,529.3	877.82	-	0.0	-	424.75
September	8,538.6 - FULL	-	8,634.5	-	962.77	283.17
	8,245.0 - 8,538.6	679.60	-	0.0	-	283.17
	2,691.3 - 8,245.0	764.55	-	0.0	-	283.17
	0.0 - 2,691.3	877.82	-	0.0	-	283.17
October	8,245.0 - FULL	-	8,387.9	-	962.77	283.17
	7,119.6 - 8,245.0	538.02	-	0.0	-	283.17
	1,223.3 - 7,119.6	622.97	-	0.0	-	283.17
	0.0 - 1,223.3	906.14	-	0.0	-	283.17
November	8,196.1 - FULL	594.65	-	0.0	-	283.17
	7,437.7 - 8,196.1	538.02	-	0.0	-	283.17
	954.2 - 7,437.7	707.92	-	0.0	-	283.17
	0.0 - 954.2	906.14	-	0.0	-	283.17
December	7,193.0 - FULL	707.92	-	621.7	-	283.17
	5,590.5 - 7,193.0	622.97	-	621.7	-	283.17
	978.6 - 5,590.5	764.55	-	621.7	-	283.17
	0.0 - 978.6	906.14	-	621.7	-	283.17
January	6,092.0 - FULL	764.55	-	499.4	-	339.80
	5,651.6 - 6,092.0	792.87	-	499.4	-	339.80
	3,425.2 - 5,651.6	736.24	-	499.4	-	339.80
	0.0 - 3,425.2	821.19	-	499.4	-	339.80
February	3,669.9 - FULL	594.65	-	0.0	-	339.80
	2,862.5 - 3,669.9	736.24	-	0.0	-	339.80
	1,223.3 - 2,862.5	651.29	-	0.0	-	339.80
	0.0 - 1,223.3	736.24	-	0.0	-	339.80
March	2,030.7 - FULL	594.65	-	0.0	-	339.80
	1,957.3 - 2,031	651.29	-	0.0	-	339.80
	1,223.3 - 1,957	538.02	-	0.0	-	339.80
	0.0 - 1,223	679.60	-	0.0	-	339.80
April 1-15	2,177.5 - FULL	622.97	-	0.0	-	339.80
	1,468.0 - 2,177.5	283.17	-	0.0	-	339.80
	146.8 - 1,468.0	481.39	-	0.0	-	339.80
	0.0 - 146.8	594.65	-	0.0	-	339.80
April 16-30	636.1 - FULL	283.17	-	0.0	-	283.17
	293.6 - 636.1	396.44	-	0.0	-	283.17
	48.9 - 293.6	283.17	-	0.0	-	283.17
	0.0 - 48.9	594.65	-	0.0	-	283.17
May	660.6 - FULL	226.53	-	0.0	-	226.53
	171.3 - 660.6	283.17	-	0.0	-	226.53
	0.0 - 171.3	226.53	-	0.0	-	226.53
June	2,079.6 - FULL	226.53	-	0.0	-	226.53
	1,614.8 - 2,079.6	509.70	-	0.0	-	226.53
	0.0 - 1,614.8	283.17	-	0.0	-	226.53
July	7,780.2 - FULL	-	8,482.9	-	962.77	283.17
	6,043.1 - 7,780.2	-	8,407.0	-	962.77	283.17
	3,498.6 - 6,043.1	566.34	-	0.0		283.17
	0.0 - 3,498.6	877.82	-	0.0	-	283.17

1/ If the Mica target end-of-month storage content is less than 8634.5 hm³, then a maximum outflow of 962.77 m³/s will apply.
2/ Mica outflows will be reduced to minimum to maintain the reservoir above the minimum Treaty storage content. This will override any flow target.

TABLE 1.1aM
(Metric Units)
ARROW PROJECT OPERATING CRITERIA
2010-11 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)	Minimum Outflow Limit 4/ (m^3/s)
January	-		URC	1,982	283.2
February	1 Feb - 31 Jul	≤ 86	URC	1,699	283.2
		>86 to <99	URC to 4404		
		≥ 99	4404		
March	1 Mar - 31 Jul	≤ 80	URC		283.2
		>80 to <93	URC to 2202		
		≥ 93	2202		
April 15	1 Apr - 31 Jul	≤ 75	URC		283.2
		>75 to <86	URC to 2202		
		≥ 86	2202		
April 30	1 Apr - 31 Jul	≤ 75	URC		283.2
		>75 to <86	URC to 2447		
		≥ 86	2447		
May	1 May - 31 Jul	≤ 84	URC		283.2
		>84 to <86	URC to 4404		
		≥ 86	4404		
June	1 Jun - 31 Jul	≤ 41	URC		
		>41 to <43	URC to 8074		
		≥ 43	8074		
July - December			URC		283.2

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.

4/ The Minimum Average Monthly Outflow Limit is an operating limit and may be reduced to as low as 141.6 m^3/s (Treaty minimum) to avoid drafting Mica+Arrow storage beyond 17.0 km^3. There is no operating minimum flow limit for June.

TABLE 1.1bM
(Metric Units)
ARROW PROJECT OPERATING CRITERIA
FOR 2010-11 ASSURED OPERATING PLAN

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

Period	JAN	FEB
Flow Limit	1,982	1,699

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

Period	JUL-MAY
Flow Limit	283.2

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
2010-11 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 DOP11 will apply these distribution factors to the monthly volume forecast at The Dalles for computing the Month-July runoff volumes required by the APOC. 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 1.1cM		**Look up Table 1.1aM**	
1 May Forecast Forecast Volume = 80.2 km^3 (May-Jul)	The Dalles Distribution Factor	Month-Jul Volume Runoff (km^3)	The Dalles Volume Runoff (km^3)	Maximum Storage Limit (hm^3)
May	1.0000	80.2	< 83.9	URC
June	0.6123	49.1	> 43.2	8074

TABLE 3M
(Metric Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2010 - 11 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	8635	8620	8552	8260	7269	5448	3541	1686	1011	406	408	1131	5129	7486
1929-30	8305	8539	8231	6108	4915	3625	1317	448	0	0	493	1272	3004	6400
1930-31	7284	8036	8055	6188	5216	3226	1937	280	0	0	0	552	2338	5162
1931-32	4968	4570	3000	2623	1568	7	6	0	0	0	0	0	0	0
							ARROW							
1928-29	8758	8736	8050	7342	6707	5974	3570	1844	1657	1844	1737	4005	7795	8659
1929-30	8670	8629	7447	7296	5072	3712	1277	421	2	6	901	3237	6364	8367
1930-31	8544	8352	7139	6890	4912	2850	830	241	18	12	55	2339	4340	4130
1931-32	4273	4561	4200	2783	2070	664	3	0	0	0	0	0	0	0
							DUNCAN							
1928-29	1727	1713	1645	1595	1442	1021	823	612	416	315	342	630	1302	1552
1929-30	1650	1561	1543	1506	1454	1107	602	319	1	2	81	362	900	1318
1930-31	1478	1463	1573	1620	1567	1017	460	145	0	0	4	385	277	378
1931-32	487	314	359	323	227	0	0	0	0	0	0	0	0	0
							COMPOSITE							
1928-29	19119	19069	18246	17198	15417	12443	7934	4142	3084	2565	2487	5766	14226	17697
1929-30	18625	18729	17222	14910	11441	8444	3196	1189	4	8	1475	4872	10267	16085
1930-31	17306	17851	16766	14698	11695	7093	3228	666	18	12	59	3276	6955	9670
1931-32	9728	9446	7559	5730	3865	671	9	0	0	0	0	0	0	0

Note: These rule curves are input to the AOP 2011 Step 1 study.
They will be adjusted to eliminate any Canadian composite crossovers according to 3 a) of the AOP document.

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
2010 - 11 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	0	1300	2774	3211	3371	3411	3398	3370	3387	3448	3603	5463	7997	8635
VARIABLE REFILL CURVES (hm^3)														
1928-29							5821	5538	5442	5455	5555	6644	7628	8635
1929-30							3320	2941	2821	2878	3260	5161	6934	"
1930-31							3950	3593	3463	3467	3687	5208	7116	"
1931-32							1519	1179	1065	1071	1357	3150	6293	"
1932-33							1290	1037	965	966	1155	2902	5895	"
1933-34							29	0	0	0	0	2281	6511	"
1934-35							2199	1901	1859	1909	2079	3656	6186	"
1935-36							1809	1512	1442	1442	1674	3667	6878	"
1936-37							5788	5455	5323	5309	5526	6674	7705	"
1937-38							2201	1903	1788	1806	2032	3698	6517	"
1938-39							3260	3070	2974	3042	3312	5052	7600	"
1939-40							2741	2461	2407	2460	2776	4569	7020	"
1940-41							4403	4097	4013	4066	4497	6133	7662	"
1941-42							3447	3150	3047	3042	3227	4702	6999	"
1942-43							3759	3407	3296	3291	3663	5233	7100	"
1943-44							6047	5675	5576	5585	5752	6942	8047	"
1944-45							5531	5250	5184	5220	5340	6424	7715	"
1945-46							785	413	294	270	493	2411	6283	"
1946-47							1064	823	774	803	1088	3049	6450	"
1947-48							939	647	562	527	722	2549	6173	"
1948-49							5089	4735	4584	4578	4767	5915	8060	"
1949-50							1808	1420	1277	1254	1460	3090	5711	"
1950-51							1787	1515	1451	1471	1749	3381	6595	"
1951-52							2782	2406	2279	2242	2441	4104	6956	"
1952-53							3470	3138	3034	3029	3174	4484	6875	"
1953-54							720	417	374	383	587	2344	5643	"
1954-55							2578	2315	2252	2277	2488	3924	6118	"
1955-56							1474	1168	1053	1036	1253	3132	6386	"
1956-57							1886	1562	1484	1497	1714	3342	7195	"
1957-58							1479	1187	1124	1150	1407	3090	6614	"
DISTRIBUTION FACTORS							0.9750	0.9770	0.9740	0.9812	0.9650	0.7950	0.4950	N/A
FORECAST ERRORS (hm^3)							1597	1248	1138	1087	1087	882	882	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s): ASSURED REFILL CURVE														
	85	85	85	85	85	85	85	85	85	85	85	100	725	1362
VARIABLE REFILL CURVES					99 km^3		85	85	85	85	85	85	821	878
(BY VOLUME RUNOFF AT THE DALLES)					117 km^3		85	85	85	85	85	85	510	680
					136 km^3		85	85	85	85	85	85	510	680
VARIABLE REFILL CURVE LOWER LIMITS (h					99 km^3		550	590	663	810	1150	3574	6909	8635
(By VOLUME RUNOFF AT THE DALLES)					117 km^3		96	0	51	67	0	1668	5620	8635
					136 km^3		29	0	0	0	9	1612	4427	8635
OPERATING RULE CURVE LOWER LIMITS (hm^3)							795	131	0	0				

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
2010 - 11 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	1921	3938	4092	4140	4264	4530	7121	8354	8758
VARIABLE REFILL CURVES (hm^3)														
1928-29							7187	6834	6499	6391	6684	7904	8188	8758
1929-30							3298	3221	3228	3267	3910	6697	8367	"
1930-31							4308	3952	3668	3640	4141	6293	8234	"
1931-32							10	0	43	12	20	2304	6712	"
1932-33							6	5	42	2	13	2219	6631	"
1933-34							5	0	42	0	11	2202	7373	"
1934-35							2184	2201	2368	2454	2888	5524	7862	"
1935-36							2390	2170	1958	1905	2298	5557	8501	"
1936-37							7941	7480	7120	6942	7288	8333	8349	"
1937-38							8	0	43	8	17	2299	7068	"
1938-39							3769	3553	3410	3374	3949	6518	8607	"
1939-40							3133	3063	3083	3325	3987	6468	8489	"
1940-41							5858	5624	5431	5703	6755	8606	8758	"
1941-42							5122	5026	4937	4897	5342	7379	"	"
1942-43							1725	1336	1155	1079	1627	4267	7949	"
1943-44							8758	8758	8559	8389	8758	8758	8758	"
1944-45							7381	7163	6921	6882	7165	8135	8710	"
1945-46							5	0	42	0	11	2202	6664	"
1946-47							10	0	43	14	21	2366	7155	"
1947-48							5	0	42	0	11	2202	6729	"
1948-49							2923	2614	2395	2316	2867	4750	8356	"
1949-50							5	0	42	0	11	2202	6615	"
1950-51							"	"	"	"	"	"	7081	"
1951-52							"	"	"	"	"	"	7011	"
1952-53							268	148	81	69	422	2789	7249	"
1953-54							5	0	42	0	11	2202	6615	"
1954-55							1282	1299	1296	1262	1764	4280	7107	"
1955-56							5	0	42	0	11	2202	6738	"
1956-57							"	"	"	"	"	"	7059	"
1957-58							9	0	43	10	18	2280	7003	"
DISTRIBUTION FACTORS							0.9710	0.9747	0.9691	0.9741	0.9530	0.7483	0.4631	N/A
FORECAST ERRORS (hm^3)							3017	2416	2019	1750	1750	1227	1227	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s)														
ASSURED REFILL CURVE														
	142	142	142	142	142	142	142	170	198	198	255	294	1787	2126
VARIABLE REFILL CURVES					99 km^3		142	142	142	142	142	142	1557	1642
(BY VOLUME RUNOFF AT THE DALLES)					117 km^3		142	142	142	142	142	142	1218	1614
					136 km^3		142	142	142	142	142	142	142	1076
VARIABLE REFILL CURVE LOWER LIMITS (h					99 km^3		339	518	926	1353	2038	5183	7437	8758
(By VOLUME RUNOFF AT THE DALLES)					117 km^3		36	0	46	79	65	2849	7226	8758
					136 km^3		5	0	42	0	11	2202	6615	8758
OPERATING RULE CURVE LOWER LIMITS (hm^3)							499	0	0	0				

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
2010 - 11 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	4	151	314	389	432	459	484	506	541	567	605	987	1360	1727
VARIABLE REFILL CURVES (hm^3)														
1928-29							835	825	818	814	855	995	1464	1727
1929-30							831	821	813	808	868	1045	"	"
1930-31							696	688	689	697	753	922	"	"
1931-32							23	7	7	0	19	370	1136	"
1932-33							16	1	2	"	9	264	1093	"
1933-34							14	0	1	"	80	564	1308	"
1934-35							143	56	63	68	127	555	1314	"
1935-36							186	62	74	60	141	587	1334	"
1936-37							678	666	664	660	712	885	1464	"
1937-38							20	4	5	13	88	490	1204	"
1938-39							403	274	278	287	365	745	1435	"
1939-40							407	256	279	311	396	748	1437	"
1940-41							473	484	496	533	645	896	1464	"
1941-42							303	320	332	342	414	729	1317	"
1942-43							286	285	293	299	394	755	1273	"
1943-44							850	852	856	857	915	1062	1464	"
1944-45							612	614	621	623	668	862	1417	"
1945-46							14	0	1	0	7	258	1129	"
1946-47							24	8	8	"	20	334	1154	"
1947-48							14	0	1	"	7	376	1188	"
1948-49							434	426	426	425	487	801	1435	"
1949-50							14	0	1	0	7	385	1088	"
1950-51							"	"	"	"	"	298	1111	"
1951-52							17	15	31	32	96	526	1232	"
1952-53							25	16	27	32	89	465	1144	"
1953-54							14	0	1	0	7	258	1088	"
1954-55							57	37	34	"	67	453	1242	"
1955-56							14	0	1	"	7	258	1112	"
1956-57							"	"	"	"	"	373	1275	"
1957-58							21	6	6	"	16	287	1161	"
DISTRIBUTION FACTORS							0.9720	0.9790	0.9740	0.9790	0.9570	0.7580	0.4690	N/A
FORECAST ERRORS (hm^3)							290	267	239	216	216	179	179	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	3	3	3	3	3	3	3	3	3	3	3	4	84	70
VARIABLE REFILL CURVES					99 km^3		3	3	3	3	3	40	42	42
(BY VOLUME RUNOFF AT THE DALLES)					117 km^3		3	3	3	3	3	3	17	31
					136 km^3		3	3	3	3	3	3	17	28
VARIABLE REFILL CURVE LOWER LIMITS (h					99 km^3		466	99	152	200	281	790	1464	1727
(By VOLUME RUNOFF AT THE DALLES)					117 km^3		68	46	41	0	81	501	1279	1727
					136 km^3		14	0	1	12	7	258	1088	1727
OPERATING RULE CURVE LOWER LIMITS (hm^3)							277	68	0	0				

TABLE 7M
(Metric Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2010 - 11 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8635	8635	8635	8388	8388	8151	7924	7718	7491	7491	7491	7777	8635	8635
1929-30	"	"	"	"	"	"	7785	7454	7088	7088	7088	7475	"	"
1930-31	"	"	"	"	"	"	8151	8151	8151	8151	8151	8272	"	"
1931-32	"	"	"	"	"	"	6604	5149	3602	3602	3602	5982	"	"
1932-33	"	"	"	"	"	"	6585	5168	"	"	"	5076	7568	"
1933-34	"	"	"	"	"	"	"	"	"	"	4357	6621	8635	"
1934-35	"	"	"	"	"	"	"	"	"	"	3602	5006	7568	"
1935-36	"	"	"	"	"	"	6604	5149	"	"	"	5806	8635	"
1936-37	"	"	"	"	"	"	7675	7243	6767	6767	6767	7981	"	"
1937-38	"	"	"	"	"	"	6585	5168	3602	3602	3602	5212	7789	"
1938-39	"	"	"	"	"	"	7002	5966	4817	4817	4817	6817	8635	"
1939-40	"	"	"	"	"	"	7364	6628	5840	5840	5840	7237	"	"
1940-41	"	"	"	"	"	"	8151	8151	8151	8151	8151	8272	"	"
1941-42	"	"	"	"	"	"	6585	5168	3602	3602	3602	5414	"	"
1942-43	"	"	"	"	"	"	"	"	"	"	4105	4608	6621	"
1943-44	"	"	"	"	"	"	8151	8151	8151	8151	8151	8272	8635	"
1944-45	"	"	"	"	"	"	6941	5847	4637	4637	4637	6132	8155	"
1945-46	"	"	"	"	"	"	6585	5168	3602	3602	3602	5937	8635	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	5831	"	"
1947-48	"	"	"	"	"	"	6604	5149	"	"	"	5967	"	"
1948-49	"	"	"	"	"	"	6585	5168	"	"	"	6511	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	3808	5997	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	4281	8162	"
1951-52	"	"	"	"	"	"	6604	5149	"	"	"	5137	7527	"
1952-53	"	"	"	"	"	"	6585	5168	"	"	"	4518	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	4815	5343	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	4865	7940	"
1955-56	"	"	"	"	"	"	6604	5149	"	"	3803	5615	7628	"
1956-57	"	"	"	"	"	"	6585	5168	"	"	3602	6818	8635	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	6018	"	"

TABLE 8M
(Metric Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2010 - 11 ASSURED OPERATING PLAN

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
8758	8758	8758	8450	8450	7887	7860	7835	7809	7809	7809	8110	8758	8758
"	"	"	"	"	"	7734	7595	7442	7442	7442	7861	"	"
"	"	"	"	"	"	7887	7887	7887	7887	7887	8164	"	"
"	"	"	"	"	"	6671	5533	4317	4317	4317	6418	"	"
"	"	"	"	"	"	6657	5547	"	"	"	5618	7816	"
"	"	"	"	"	"	"	"	"	"	5658	6595	8758	"
"	"	"	"	"	"	"	"	"	"	4317	5556	7816	"
"	"	"	"	"	"	6671	5533	"	"	"	6262	8758	"
"	"	"	"	"	"	7633	7404	7150	7150	7150	8195	"	"
"	"	"	"	"	"	6657	5547	4317	4317	4317	5738	8012	"
"	"	"	"	"	"	7023	6242	5378	5378	5378	7149	8758	"
"	"	"	"	"	"	7349	6847	6309	6309	6309	7533	"	"
"	"	"	"	"	"	7887	7887	7887	7887	7887	8164	"	"
"	"	"	"	"	"	6657	5547	4317	4317	4317	5916	"	"
"	"	"	"	"	"	"	"	"	"	4859	5063	6702	"
"	"	"	"	"	"	7887	7887	7887	7887	7887	8164	8758	"
"	"	"	"	"	"	6968	6139	5220	5220	5220	6543	8333	"
"	"	"	"	"	"	6657	5547	4317	4317	4317	6378	8758	"
"	"	"	"	"	"	"	"	"	"	"	6284	"	"
"	"	"	"	"	"	6671	5533	"	"	"	6404	"	"
"	"	"	"	"	"	6657	5547	"	"	"	6884	"	"
"	"	"	"	"	"	"	"	"	"	"	4499	6431	"
"	"	"	"	"	"	"	"	"	"	"	4917	8340	"
"	"	"	"	"	"	6671	5533	"	"	"	5672	7781	"
"	"	"	"	"	"	6657	5547	"	"	"	5125	"	"
"	"	"	"	"	"	"	"	"	"	"	5387	5854	"
"	"	"	"	"	"	"	"	"	"	"	5432	8145	"
"	"	"	"	"	"	6671	5533	"	"	4677	6013	7745	"
"	"	"	"	"	"	6657	5547	"	"	4317	7155	8758	"
"	"	"	"	"	"	"	"	"	"	"	6449	"	"

TABLE 9M
(Metric Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2010 - 11 ASSURED OPERATING PLAN

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1727	1727	1727	1727	1727	1233	1023	833	833	833	833	1085	1405	1727
"	"	"	"	"	"	1000	789	789	789	789	1054	1389	"
"	"	"	"	"	"	956	705	705	705	705	994	1359	"
"	"	"	"	"	"	678	160	160	160	160	688	1492	"
"	"	"	"	"	"	670	"	"	"	"	469	1403	"
"	"	"	"	"	"	"	"	"	"	311	831	1481	"
"	"	"	"	"	"	"	"	"	"	160	458	1194	"
"	"	"	"	"	"	678	"	"	"	"	860	1727	"
"	"	"	"	"	"	925	646	646	646	646	951	1338	"
"	"	"	"	"	"	718	253	253	253	253	602	1351	"
"	"	"	"	"	"	704	226	226	226	226	976	1727	"
"	"	"	"	"	"	741	281	281	281	281	1004	"	"
"	"	"	"	"	"	845	494	494	494	494	842	1283	"
"	"	"	"	"	"	806	419	419	419	419	1076	1727	"
"	"	"	"	"	"	813	434	434	434	539	706	1598	"
"	"	"	"	"	"	1019	819	819	819	819	1075	1400	"
"	"	"	"	"	"	941	677	677	677	677	1207	1727	"
"	"	"	"	"	"	670	160	160	160	160	789	1584	"
"	"	"	"	"	"	"	"	"	"	"	768	1540	"
"	"	"	"	"	"	678	"	"	"	"	735	1727	"
"	"	"	"	"	"	907	613	613	627	676	1062	"	"
"	"	"	"	"	"	670	160	160	160	160	450	1285	"
"	"	"	"	"	"	"	"	"	"	"	698	1307	"
"	"	"	"	"	"	678	"	"	"	"	539	937	"
"	"	"	"	"	"	670	"	"	"	"	574	1279	"
"	"	"	"	"	"	"	"	"	"	"	580	1340	"
"	"	"	"	"	"	"	"	"	"	"	378	1196	"
"	"	"	"	"	"	678	"	"	"	207	652	1432	"
"	"	"	"	"	"	670	"	"	"	160	920	1604	"
"	"	"	"	"	"	"	"	"	"	"	879	1727	"

TABLE 10M
(Metric Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2010 - 11 ASSURED OPERATING PLAN

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
19119	19069	18246	17198	15417	12443	8302	8074	8068	8280	8738	13570	17175	19119
"	"	"	"	"	"	7440	6773	6590	6713	7775	12845	16647	"
"	"	"	"	"	"	8175	7934	7595	7655	8349	12423	16710	"
"	"	"	"	"	"	2295	1248	1115	1084	1396	5824	14141	"
"	"	"	"	"	"	2066	1106	1009	968	1177	5385	13619	"
"	"	"	"	"	"	1572	200	43	0	92	5047	15191	"
"	"	"	"	"	"	4660	4170	4290	4431	5095	9638	15197	"
"	"	"	"	"	"	4476	3750	3475	3407	4113	9811	16566	"
"	"	"	"	"	"	8157	8074	8068	8280	8738	13468	17392	"
"	"	"	"	"	"	2978	1971	1835	1827	2137	6487	14790	"
"	"	"	"	"	"	7432	6850	6609	6642	7487	12315	17314	"
"	"	"	"	"	"	6281	5780	5769	6066	7044	11785	16734	"
"	"	"	"	"	"	7952	7946	8021	8207	8627	13425	17299	"
"	"	"	"	"	"	7688	7562	7519	7648	7958	11347	16671	"
"	"	"	"	"	"	5551	4991	4745	4669	5624	9581	14596	"
"	"	"	"	"	"	8302	8074	8068	8280	8738	13570	17711	"
"	"	"	"	"	"	8091	8074	8068	8280	8738	12868	17408	"
"	"	"	"	"	"	1572	481	337	270	512	4871	14076	"
"	"	"	"	"	"	1840	891	825	817	1129	5749	14758	"
"	"	"	"	"	"	1715	715	605	527	741	5127	14089	"
"	"	"	"	"	"	6898	6410	6208	6189	6956	11014	17711	"
"	"	"	"	"	"	2585	1489	1320	1254	1479	5677	13230	"
"	"	"	"	"	"	2563	1584	1493	1471	1767	5881	14787	"
"	"	"	"	"	"	3559	2475	2352	2274	2549	6832	14904	"
"	"	"	"	"	"	4247	3355	3143	3130	3685	7738	15267	"
"	"	"	"	"	"	1572	486	417	383	606	4804	12285	"
"	"	"	"	"	"	4138	3682	3581	3539	4319	8581	14421	"
"	"	"	"	"	"	2250	1236	1096	1036	1271	5592	14237	"
"	"	"	"	"	"	2663	1631	1527	1497	1733	5917	15530	"
"	"	"	"	"	"	2256	1255	1173	1160	1442	5658	14779	"

TABLE 11M
(Metric Units)
COMPOSITE END STORAGE
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2010 - 11 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119	19069	18246	17198	15417	12443	7934	4142	3084	2565	2487	5766	14226	17697
1929-30	18625	18729	17222	14909	11441	8444	3196	1189	4	8	1475	4872	10267	16085
1930-31	17306	17851	16766	14698	11695	7093	3228	666	18	12	59	3276	6955	9669
1931-32	9728	9445	7558	5730	3865	671	9	0	4	436	933	5078	13984	18732
1932-33	19116	19069	17193	15419	15166	12443	7294	3301	1009	968	1177	5385	13619	18892
1933-34	19119	19069	18246	17198	15417	12537	7695	3739	1825	1461	3055	7012	12198	15958
1934-35	16895	17278	15657	13969	14379	11910	6785	4170	2525	2201	2355	6554	13637	18968
1935-36	19119	19007	18017	16233	13476	9788	4654	2929	2637	2262	2842	9653	16547	18968
1936-37	19119	18896	17573	15458	12089	8387	3286	1356	4	0	49	3318	10716	15030
1937-38	15134	14814	13084	11562	10811	8830	3624	1971	1835	1590	1920	5879	14110	18960
1938-39	18904	18723	17788	16285	14090	11509	7484	6220	3462	3478	3808	10387	15147	18968
1939-40	19119	18948	17672	16113	13908	11734	6549	5780	4606	4995	5828	11221	15600	17696
1940-41	18373	18433	17314	16656	14342	11490	7475	6244	5597	5975	6596	9430	11455	14460
1941-42	14981	15106	14895	15853	15417	12463	7857	6558	3005	2544	2835	7041	13642	18633
1942-43	19087	19069	18007	16313	14830	12443	7013	4991	2914	2501	3093	6045	11283	17896
1943-44	18899	19069	18156	17065	15117	12406	8020	4766	3054	2743	2768	4868	8491	10833
1944-45	11343	11212	9532	8282	6443	2913	1453	452	2	0	10	4103	11357	15529
1945-46	15555	15270	13541	12074	10463	7943	2585	481	246	270	512	4871	14027	18892
1946-47	19119	19069	18246	17174	15417	12443	7091	3105	825	825	1129	5749	14713	18892
1947-48	19048	18994	18246	17198	15417	12443	7205	2977	1137	527	741	5127	14089	19100
1948-49	19119	19069	18246	17198	15417	12443	7097	6410	3892	3263	3535	9758	14880	17159
1949-50	18140	18421	17144	15362	14801	12443	7087	3035	1320	1254	1479	4745	12220	18892
1950-51	19119	19069	18246	17198	15417	12443	7503	3478	1653	1631	1920	5881	13223	18892
1951-52	19119	19069	18246	17198	15417	12443	7090	2926	2352	2274	2549	6832	14212	18818
1952-53	19119	18993	17893	16106	13400	10300	4989	3355	2569	2234	2349	6018	13387	18402
1953-54	18899	19069	18246	17198	15417	12443	7235	3449	1524	878	606	4804	12262	19119
1954-55	19119	19069	18246	17198	15417	12443	7353	3682	3451	3513	2601	5189	14421	18892
1955-56	19119	19069	18246	17198	15417	12443	7443	3143	1096	1037	1271	5592	14237	18892
1956-57	19027	19069	18246	17198	15417	12443	7140	3138	1527	1497	1733	5917	14615	17422
1957-58	18235	18415	17141	15930	13816	11573	6341	2466	1173	1160	1442	5658	14779	17594

TABLE 12M
(Metric Units)
COMPARISON OF
RECENT ASSURED OPERATING PLAN STUDIES

	2003-04 2004-05 1/	2005-06	2006-07 through 2008-09 2/	2009-10	2010-11
MICA TARGET OPERATION					
(hm³ [xxxx.x] or m³/s [xxxx.xx])					
AUG 15	8561.1	8560.9	8451.0	8451.0	8414.3
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	8622.1	FULL	FULL	FULL
OCT	8255.1	8181.7	8387.9	8387.9	8387.9
NOV	566.34	651.29	566.34	622.97	594.65
DEC	651.29	707.92	707.92	707.92	707.92
JAN	707.92	736.24	679.60	651.29	764.55
FEB	594.65	622.97	594.65	566.34	594.65
MAR	538.02	566.34	509.70	481.39	594.65
APR 15	499.4	453.07	509.70	509.70	622.97
APR 30	424.75	368.12	339.80	311.49	283.17
MAY	283.17	283.17	283.17	283.17	226.53
JUN	283.17	283.17	283.17	283.17	226.53
JUL	8438.8	8438.6	8267.6	8407.0	8482.9
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (hm³)					
1928 AUG 31	19105.3	18785.7	19049.5	19111.9	19069.0
1928 DEC	12756.1	12083.5	12560.4	12503.3	12443.4
1929 APR15	3910.9	2268.2	2053.4	1642.9	2564.5
1929 JUL	17813.0	17669.3	17487.6	17539.4	17696.7
COMPOSITE CANADIAN TREATY STORAGE CONTENT (hm³)					
60-Yr Average					
AUG 31	18141.5	17709.2	18008.7	18240.6	18197.7
DEC	11644.6	10856.3	11339.7	11353.0	11286.0
APR15	2685.6	2656.5	2883.3	2147.6	2061.6
JUL	17767.2	17653.4	17600.1	17805.4	17784.1
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-1.2	-0.1	-0.2	-0.3	-0.3
U.S. Dependable Peaking Capacity	16.0	-51.0	-21.0	-2.7	-19.1
U.S. Average Annual Usable Secondary Energy	12.9	10.5	0.3	13.8	16.0
BCH Firm Energy	43.1	97.7	90.3	50.2	34.4
BCH Dependable Peaking Capacity	8.0	2.0	11.0	44.9	43.8
BCH Average Annual Usable Secondary Energy	-24.3	-55.7	-29.3	-28.2	-20.8
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	10439	11097	11137	11138	11138
AUG 31	10435	11125	11165	11166	11167
SEP	10101	10809	10849	10850	11025
OCT	10186	9742	9782	9783	9958
NOV	11807	10817	11157	11157	11333
DEC	13377	12853	13192	13193	13369
JAN	13122	12735	13075	13076	13076
FEB	12240	11561	11901	11901	11902
MAR	11175	11275	11315	11316	10967
APR 15	10541	10550	10589	10590	10241
APR 30	13065	14061	12822	12823	12475
MAY	13752	14729	13491	13491	13493
JUN	13114	14039	14079	14079	14080
JUL	12079	12383	12723	12724	12725
ANNUAL AVERAGE	12037	12034	12037	12038	12039

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 2010-11 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 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 Rate 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 Rate 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 426.3 ksfd 2890.0 ft	881.79 m 1043 hm^3 880.9 m	May	
		0.0 ksfd 2883.0 ft	0 hm^3 878.74 m	Empty Apr 15	FERC, AOP80.
	Maximum Content	58.6 ksfd 2884.0 ft	143.37 hm^3 879.04 m	March (Included to help meet the Apr 15 FERC requirement.)	In place in AOP80, AOP84.
	Other	0.0 ksfd 2883.0 ft	0 hm^3 878.74 m	Conditions permitted, should be on or about, empty Mar and Apr 15.	FERC, AOP80.
Thompson Falls (1490)				None Noted	

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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	
				None Noted	

Appendix A
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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.

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 2518.3 ksfd 1287.0 ft	6256.1 hm^3 392.58 m 6161.2 hm^3 392.28 m	Aug-Nov Dec-Feb	
	Draft Rate 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	1000 cfs	28.3 m^3/s	All periods	2/1/05 C. Wagers, Douglas 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

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Project Operating Procedures for the 2010-11
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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.

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
	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.	

Appendix A
Project Operating Procedures for the 2010-11
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.

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	
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 2128.0 ft	275.2 hm^3 648.6 m	May - Aug 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.

Appendix A
Project Operating Procedures for the 2010-11
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.

Other Major Step I Projects					
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 2363.0 ft	1900.7 hm^3 720.24 m	1929 Dec	2-1-93 PNCA submittal, in plac in AOP99.
		676.5 ksfd 2355.0 ft	1655.1 hm^3 717.80 m	1929 Jan	
		603.6 ksfd 2349.0 ft	1476.8 hm^3 715.98 m	1929 Feb	
		2147.7 ksfd 2443.0 ft	5254.5 hm^3 744.63 m	1929 Jul	
		652.0 ksfd 2353.0 ft	1595.2 hm^3 717.19 m	1930 Dec	
		433.2 ksfd 2334.0 ft	1059.9 hm^3 711.40 m	1930 Jan	
		389.3 ksfd 2330.0 ft	952.5 hm^3 710.18 m	1930 Feb	
		348.5 ksfd 2326.0 ft	852.6 hm^3 708.96 m	1930 Mar	
		297.4 ksfd 2321.0 ft	727.6 hm^3 707.44 m	1930 Apr 15	
		444.2 ksfd 2335.0 ft	1086.8 hm^3 711.71 m	1930 Apr 30	
		499.1 ksfd 2340.0 ft	1221.1 hm^3 713.23 m	1930 May	
		1344.6 ksfd 2402.0 ft	3289.7 hm^3 732.13 m	1930 Jun	
		1771.9 ksfd 2425.0 ft	4335.1 hm^3 739.14 m	1930 Jul	
		317.8 ksfd 2323.0 ft	777.5 hm^3 708.05 m	1931 Dec	
		192.2 ksfd 2310.0 ft	470.2 hm^3 704.09 m	1931 Jan	
		103.1 ksfd 2300.0 ft	252.2 hm^3 701.04 m	1931 Feb-Apr 30	
		192.2 ksfd 2310.0 ft	470.2 hm^3 704.09 m	1931 May	
		676.5 ksfd 2355.0 ft	1655.1 hm^3 717.80 m	1931 Jun	
		868.0 ksfd 2370.0 ft	2123.6 hm^3 722.38 m	1931 Jul	
		174.4 ksfd 2308.0 ft	426.7 hm^3 703.48 m	1932 Dec	
		103.1 ksfd 2300.0 ft	252.2 hm^3 701.04 m	1932 Jan	
		0.0 ksfd 2287.0 ft	0.0 hm^3 697.08 m	Empty at end of CP***	
		776.9 ksfd 2363.0 ft	1900.7 hm^3 720.24 m	All Dec	
			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.

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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 Oct-May and meets target operation Jun-Sep to obtain uniform ouflows Jul-Aug			2-1-05 PNCA submittal
	Target Operation:	779.3 ksfd	1906.6 hm^3	Jul	2-1-05 PNCA submittal Jul-Aug 15 and Sep based on 60 Median .
		1573.2 ft	479.51 m		
		642.4 ksfd	1571.7 hm^3	Aug 15	
		1555.4 ft	474.09 m		
		490.1 ksfd	1199.1 hm^3	Aug 31	
		1534 ft	467.56 m		
		392.9 ksfd	961.26 hm^3	Sep	
		1519.6 ft	463.16 m		
		1016 ksfd	2485.7 hm^3	Jun	
		1600 ft	487.68 m		
	Other Spill	100 cfs	2.8 m^3/s	All periods	
Lower Granite (520)	Bypass Date			None	
	Other Spill	500 cfs	14.2 m^3/s	Jul - Oct	2-1-05 PNCA submittal
		400 cfs	11.3 m^3/s	Nov - Dec	
		100 cfs	2.8 m^3/s	Jan	
		200 cfs	5.7 m^3/s	Feb- Mar	
		460 cfs	13.0 m^3/s	Apr 15 - Jun	
	Incremental Spill			Removed	
	Fish Spill Trigger	70000 cfs	1982.2 m^3/s	No fish spill if seasonal average regulated outflow at LWG is less-than this flow.	2-3-04 PNCA submittal
	Trigger	85000 cfs	2406.9 m^3/s	When seasonal average regulated outflow at LWG is between targets, spill thru April 20, if greater than 85 kcfs spill thru Jun 20.	
		17267 cfs	488.9 m^3/s	Apr 15 [19 kcfs or 20 kcfs alternating for 13 days]	Variable RSW+BiOp spill regimes for Apr 3 thru Jun 20.
	19000	6300 cfs	538.0 178.4 m^3/s	Apr 30 (trigger)	Spill ending Apr 20 or Jun 20 dependent on LWG runoff triggers.
		19032 cfs	538.9 m^3/s	May	
		13333 cfs	377.5 m^3/s	June [19 kcfs or 20 kcfs alternating for 20 days]	
	Maximum Fish Spill	40000 cfs	1132.7 m^3/s	Instantaneous	
	Minimum Flow	11500 cfs	325.6 m^3/s	Mar-Nov	

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	Other		224.9 ksfd		550.2 hm^3	On MOP Apr - Oct 31.	
			733.0 ft 245.8 ksfd 738.0 ft		223.42 m 601.4 hm^3 224.94 m	On full pool Nov 30 - Mar 31.	
Little Goose (518)	Bypass Date					None	
	Other Spill		600 cfs 450 cfs 150 cfs 300 cfs 600 cfs		17.0 m^3/s 12.7 m^3/s 4.2 m^3/s 8.5 m^3/s 17.0 m^3/s	Jul - Nov Dec Jan Feb - Mar Apr 15 - Jun	2-1-05 PNCA submittal
	Incremental Spill					Removed	
	Fish Spill		70000 cfs		1982.2 m^3/s	No fish spill if seasonal average regulated outflow at LWG is less-than this flow.	2-1-04 PNCA submittal
			85000 cfs		2406.9 m^3/s	When seasonal average regulated outflow at LWG is between targets, spill thru April 20, if greater than 85 kcfs spill thru Jun 20.	
			16467 cfs		466.3 m^3/s	Apr 15 [(38000/2)*13/15]	Variable nighttime spill regimes for Apr 3 thru Jun 20.
		19000	6333 cfs	538.0	179.3 m^3/s	Apr 30	Spill ending Apr 20 or Jun 20 dependent on seasonal average regulated outflow @ LWG.
			19000 cfs 12677 cfs		538.0 m^3/s 359.0 m^3/s	May 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 633.0 ft 285.0 ksfd 638.0 ft		106.5 hm^3 192.94 m 697.3 hm^3 194.46 m	On MOP Apr - Aug 31. On full pool Sep 30 - Mar 31.	
Lower Monumental (504)	Bypass Date					A bypass date of 2010 was assumed.	
	Other Spill		850 cfs 750 cfs 600 cfs 300 cfs 500 cfs 850 cfs		24.1 m^3/s 21.2 m^3/s 17.0 m^3/s 8.5 m^3/s 14.2 m^3/s 24.1 m^3/s	Jul - Oct Nov Dec Jan - Feb Mar Apr 15 - Jun	2-1-05 PNCA submittal
	Fish Spill		70000 cfs		1982.2 m^3/s	No fish spill if regulated flow at LWG is less than 70 kcfs.	2-1-04 PNCA submittal Duration of spill dependent on LWG seasonal average regulated outflow.
			85000 cfs		2406.9 m^3/s	When seasonal average regulated outflow at LWG is between targets, spill thru April 20, if greater than 85 kcfs spill thru Jun 20.	

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		75000 cfs	2123.8 m^3/s	If regulated outflow @ LMN < 75 kcfs or >100 kcfs, spill is 50% of LMN regulated ouflow.	Monthly spill amounts dependent on total river flow @ LMN.
		100000 cfs	2831.7 m^3/s	If regulated outflow @ LMN is between 75 & 100 kcfs, spill is 45% of LMN regulated outflow.	
	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 537.0 ft	441.6 hm^3 163.68 m	On MOP Apr - Aug 31.	
		190.1 ksfd 540.0 ft	465.1 hm^3 164.59 m	On full pool Sep 30 - Mar 31.	
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	
Lower Baker (2025)	Max Storage Limits	67.0 ksfd 442.4 ft	163.9 hm^3 134.84 m	Jul - Aug 31	2-1-05 PNCA submittal
		40.1 ksfd 415.9 ft	98.1 hm^3 126.77 m	Sep	
		34.7 ksfd 409.8 ft	84.9 hm^3 124.91 m	Oct - Dec	
		45.2 ksfd 421.4 ft	110.6 hm^3 128.44 m	Jan - Mar	
		46.7 ksfd 423.0 ft	114.3 hm^3 128.93 m	Apr 15	
		67.0 ksfd 442.4 ft	163.9 hm^3 134.84 m	Apr 30 - Jun	
		11.2 ksfd 378.8 ft	27.4 hm^3 115.46 m	All periods	
Upper Baker (2028)	Max Storage Limits	107.4 ksfd 727.8 ft	262.8 hm^3 221.83 m	Jul - Sep	2-1-05 PNCA submittal
		82.3 ksfd 717.0 ft	201.4 hm^3 218.54 m	Oct	
		70.9 ksfd 711.7 ft	173.5 hm^3 216.93 m	Nov - Feb	
		107.4 ksfd 727.8 ft	262.8 hm^3 221.83 m	Mar - Jun	
	Min Storage Limits	69.3 ksfd 710.8 ft	169.5 hm^3 216.65 m	Jul - Aug 31	
		65.6 ksfd 708.8 ft	160.5 hm^3 216.04 m	Sep - Oct	
		16.6 ksfd 677.8 ft	40.6 hm^3 206.59 m	Nov - Mar	
		38.0 ksfd 693.8 ft	93.0 hm^3 211.47 m	Apr 15 - Apr 30	
		69.3 ksfd 710.8 ft	169.5 hm^3 216.65 m	May - Jun	
Timothy (117)	Minimum Content	24.5 ksfd 3180.0 ft	59.9 hm^3 969.26 m	Oct - May	3-6-01 PNCA submittal
		31.1 ksfd 3190.0 ft	76.1 hm^3 972.31 m	Jun - Aug 31	
		27.8 ksfd 3185.0 ft	68.0 hm^3 970.79 m	Sep	
Long Lake (1305)	Minimum Content	50.1 ksfd 1535.0 ft	122.6 hm^3 467.87 m	Apr - Nov	2-5-02 PNCA submittal
		19.7 ksfd 1522.0 ft	48.2 hm^3 463.9 m	Dec - Mar	
	Draft Rate Limit	1.0 ft/day	0.30 m/day		2-1-03 PNCA submittal

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Priest Lake (1470)	Maximum Content	0.0 ksfd 0.0 ft	0.0 hm^3 0.00 m	Oct	2-1-03 PNCA submittal
	Max/Min Content	35.5 ksfd 3.0 ft	86.9 hm^3 0.91 m	Maintain at or near after runoff through Sep.	
Ross (2070)	Minimum Content/			Dependent on Skagit Fisheries.	2-1-05 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 2010-11

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DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB) FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2010-11

January 2006

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 2010-11 Determination of Downstream Power Benefits (DDPB11) developed from the 2010-11 Assured Operating Plan (AOP11).

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 DDPB, the Entities have agreed to the following changes from the procedures in POP:

- Use only the first of the three Streamline Procedures, "Forecasting Loads and Resources," as defined in Appendix 6 of the POP;

- Revise adjustment for Canadian critical rule curve crossovers (see AOP11 subsection 3a);

- Implement the Arrow Project Operating Criteria (see AOP11 subsection 4c(2)); and
- Do not adjust Variable Refill Curve Lower Limits for crossovers as defined in POP Appendix 1 (see AOP11 subsection 7d).

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 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 base hydro system operated for flood control and optimum power generation in the United States.

As part of the DDPB11, 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 2010-11 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	= 1316.4 megawatts (MW)
Average Annual Usable Energy	= 535.7 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 2.0 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 DDPB11, 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 AOP11.

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 Steps 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) 2004 White Book (WB04) load forecast, as updated through 21 April 2005. The Grand Coulee pumping load is included in this estimate. The method for computing the firm load for the Steps II and III studies is described in the 1988 Entity agreements and in the POP.

Table 4 Summary of Power Regulations from 2010-11 Assured Operating Plan:

This table summarizes the results of the Steps I, II, and III power regulation studies for each project and the total system. The determination of the Steps 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 2010-11 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 Steps 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, plus the remaining usable energy. 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 the 2009-10 AOP 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 DDPB11 studies follows.

a) Loads

Loads for the AOP11 are based on Bonneville Power Administration's (BPA) 21 April 2005 Draft 2004 White Book (WB04) medium-case load forecast. The Draft WB04 regional load forecast for the AOP11 is 361 annual aMW (1.6%) less than the WB02 forecast used in the AOP10. However, because only a portion of the Utah Power & Light load is excluded in the AOP11 (explained below) the net PNWA firm load from the AOP10 to AOP11 goes down by only 235 annual aMW (1%). The Draft WB04 forecast includes reductions to Generating Public and Investor-owned entity loads. The Draft WB04 forecast of the 2011 average annual firm load is 22,293 MW, and is based on a 1.25% annual load growth from the 2010 operating year. Other load assumptions and changes include:

- The Utah Power & Light (UP&L) load in eastern Idaho that was excluded from White Book totals in the AOP10 and prior AOPs has been modified to reflect 1) the updated WB04 UP&L Idaho load forecast, 2) the exclusion of only the smaller area served by UP&L in 1964, and 3) the removal of the transfer loads to other utilities included in UP&L's service area. Annex B, paragraph 7, of the Treaty requires the area served by UP&L in 1964 to be excluded from the PNWA firm load. All of the UP&L load and import supporting it, were excluded from previous AOPs. The AOP11 will exclude 57.3 % of the UP&L load in Idaho from the PNWA firm load, and all of the import from Utah will continue to be excluded, although now only the portion serving the AOP load area for UP&L will be classified as a thermal installation. The net effect of these UP&L Idaho load changes on the AOP11 Step I loads is a 125 annual aMW increase in the PNWA firm load compared to AOP10.
- The WB04 does not include transmission losses in the firm load forecast, but instead decreases all resources (including imports) by 2.67% energy and 3.20% peak to account for transmission grid and step-up transformer power losses. Transmission losses are no longer included White Book loads because the load forecast in most cases is for the point of delivery at the utility's connection to the grid. This procedure began with the WB99 and should have been included in the 2006-07 and later AOPs. Those AOP Step I studies did include a reduction for federal hydro generation step-up transformer losses, but not the grid losses and step-up transformer losses for some other resources. The AOP11 calculation assumes that 68% of the resources (based on federal and Mid-C hydro, large thermal, and import thermal) are measured at the grid connection and therefore should not include the estimated 0.22% step-up transformer losses. The effect on the AOP11 Step I study, compared to the AOP10, of including the additional transmission losses is to increase the Step I System load by 637 annual aMW.
- The average critical period load factor increased from 73.85% in AOP10 (from WB02) to 75.89% in AOP11 (from WB04). This was mainly due to a change in forecast procedure, with more collaboration on development of public and investor owned utilities loads in the WB04 and changes to the commercial loads. Excluding a smaller portion of the UP&L load in Idaho (92% load factor) also contributed to the increase in the system load factor.
- Updated irrigation pumping loads for the Grand Coulee are included in the Regional Firm Load. Both these irrigation loads and the pumping amounts were obtained from the February 2005 Pacific Northwest Coordination Agreement (PNCA) data submittal from the Bureau of Reclamation which was based on the previous five year average discharge into Banks Lake.

Differences from the WB04 vary from -68 aMW in Apr2 to 48 aMW in Sept., with a net annual difference of 0.5 aMW.

- 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 2010-11 Energy Entitlement from BPA's WB04. The estimated and the computed Canadian Entitlement are shown below:

During 1 August 2010 – 31July 2011

Canadian Entitlement	Energy (aMW)		Capacity (MW)	
Return	Estimated	Computed	Estimated	Computed
Export to BC (1/2)	269.0	267.9	676.0	658.2
Retained in PNW (1/2)	269.0	267.9	676.0	658.2
Total	538.0	535.7	1352.0	1316.4

Iterative studies to update the Canadian Entitlement in the load estimate were not performed because the effect on the amount of the thermal installations would not significantly affect the results of the studies.

- Compared to the AOP10, Flows-Out (exports that are mostly to the southwest) increased by 12 annual aMW, and Flows-In (imports) decreased by 146 annual 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 is an 80 annual aMW increase 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 and later 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 CGS, to meet the Step I System Load minus Step I Hydro capability. The annual shape of the generic Thermal Installation was based on the sum of WB04 thermal resources, 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 included in the 2010-11 study. The total Thermal Installations increased by 478 annual aMW compared to the AOP10, mainly due to the impact of additional transmission losses.

The TDM increased by 275 annual aMW due to the combination of increased thermal installations explained above (478 annual aMW), an increase in system sales (189 annual aMW), and a slight increase (15 aMW) in Minimum Thermal Generation.

c) Hydro Project Modified Streamflows

The base unregulated streamflows used in the System Regulation Studies are 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. Forecasts of Grand Coulee pumping estimates were updated from the February 2005 PNCA data submittal, but the Grand Coulee return flows were not updated, because return flow is assumed in the 2000 Modified Streamflow record and the update volumes are minimal.

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 used since the AOP07. 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 Steps II and III studies were the same as the AOP11 Step I study. The Grand Coulee URC in the 2006-07 through 2010-11 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 the Grand Coulee flood control rule curve for this operating year on a "without prejudice" basis.

- The procedure for adjusting Canadian CRCs for crossovers was revised as described in AOP11 subsection 3a.

- The past practice of raising the 80 Maf VRCLL to the CRC1 was not used in the AOP11 studies after it was determined that it adversely affected optimum power generation.

- Brownlee's critical rule curves and operating rule curves were updated for AOP11 to approximate the historic operation of Brownlee during 1975 through 1985 (prior to modern fishery constraints), except for modifications needed by the 1988 and 1996 Entity Agreements that allow starting the critical period full and ending the critical period empty.

- The VarQ flood control rule curves are used for Hungry Horse, and has been the same since the AOP07.

e) Other 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. Other changes and notable assumptions include:

- Brownlee minimum flow requirements were 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.
- Cabinet Gorge generation vs discharge and spill vs discharge tables are updated.
- Rock Island generation vs discharge table is updated.

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

Step II and Step III critical period regulation studies for the 2010-11 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 decreased from 1352.3 MW in the 2009-10 DDPB (DDPB10) to 1316.4 MW in the DDPB11, a decrease of 35.9 MW. The change was mainly due to a 2.04% increase in the average critical period load factor, from 73.85% to 75.89%.

The Canadian Energy Entitlement decreased from 567.1 aMW in the DDPB10 to 535.7 aMW in the DDPB11 for a decrease of 31.4 aMW. The change was mainly due to the 275 annual aMW increase in the TDM and the change in the annual shape of the thermal installation generation due to maintenance at the CGS nuclear power plant and use of WB04 thermal resource shape for the Generic Thermal Installations.

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

TABLE 1A
2010-11 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 Avg.	CP Avg. 2/
1. **Pacific Northwest Area (PNWA) Firm Load**																
a) White Book Regional Firm Load 3/	21606	21544	20295	20639	22635	24785	25228	24109	22415	21392	21452	20925	21416	22144	22293	22377
b) Exclude 57% of UPL's Idaho load 4/	-297	-297	-266	-238	-231	-241	-229	-235	-238	-231	-231	-261	-312	-348	-261	-258
c) Updates to Coulee pumping 5/	-60	-22	48	-34	15	30	8	6	29	-39	-68	27	-7	-21	1	2
d) ....Total PNWA Firm Loads	21249	21225	20077	20367	22419	24574	25007	23880	22206	21122	21153	20691	21097	21775	22033	22120
e) Annual Load Shape in Percent	96.44	96.33	91.12	92.44	101.75	111.53	113.50	108.38	100.78	95.86	96.00	93.91	95.75	98.83	100	100
2. **Flows-Out of firm power from PNWA**																
a) WB04 Exports 6/	931	932	939	891	875	885	882	881	874	892	884	782	958	951	895	895
b) Remove WB04 Canadian Entitle.	-527	-527	-527	-527	-527	-527	-527	-527	-527	-527	-527	-527	-527	-527	-527	-527
c) Add estimated Canadian Entitle. 7/	269	269	269	269	269	269	269	269	269	269	269	269	269	269	269	269
d) Added Seasonal Exch. export 8/	482	471	1474	189	0	0	0	0	0	0	502	454	2604	1502	578	534
e) Thermal install.used outside region 9/	200	227	215	151	97	0	234	274	263	237	212	168	307	309	204	198
f) ... Subtotal for Table 2	1356	1372	2370	972	714	627	858	897	879	871	1339	1146	3611	2505	1419	1369
g) Remove Plant Sales	-173	-173	-173	-173	-173	-173	-173	-173	-173	-173	-165	-36	-173	-173	-161	-163
h) Remove Flow-through-transfer	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75	-60	-59
i) ... Total	1108	1124	2122	754	496	409	640	679	661	623	1099	1035	3363	2257	1198	1148
3. **Flows-In of firm power to PNWA, except from coordinated thermal installations**																
a) WB04 Imports 10/	-914	-885	-875	-877	-985	-1111	-875	-849	-771	-723	-717	-674	-785	-856	-857	-867
b) Exclude UP&L imports for 1(b)	297	297	266	238	231	241	229	235	238	231	231	261	312	348	261	258
c) Remove Thermal Install Imports 11/	506	478	497	557	606	705	468	427	366	353	372	309	358	391	462	474
d) Add Seasonal Exchange Imports 8/	0	0	0	0	-402	-561	-1695	-1923	-1631	-1651	0	0	0	0	-578	-596
e) Remove Flow-Through-Transfer	75	75	75	45	45	45	45	45	45	75	75	75	75	75	60	59
f) ... Total	-36	-35	-37	-37	-505	-681	-1828	-2065	-1753	-1715	-39	-29	-40	-42	-652	-673
4. **PNWA Non-Step I Hydro and Non-thermal Resources**																
a) Hydro Independents (1929 water)	-1282	-1255	-1175	-1201	-1231	-1159	-1102	-924	-1045	-1281	-1327	-1772	-1727	-1426	-1280	-1144
b) Non-Step I Coord.Hydro (1929)	-502	-450	-558	-933	-899	-944	-947	-478	-702	-761	-733	-709	-1300	-636	-779	-813
c) Misc. Resources (Wind) 12/	-335	-335	-329	-337	-346	-317	-248	-242	-548	-380	-380	-389	-386	-378	-354	-346
d) Misc. WB04 Resc.(NUG Hydro)	-167	-167	-141	-116	-125	-113	-104	-112	-132	-180	-179	-221	-232	-203	-154	-149
e) Misc. WB04 Resc.(Renewables)	-80	-80	-80	-81	-82	-84	-85	-84	-84	-83	-83	-58	-80	-80	-80	-80
f) ... Total (1929)	-2365	-2286	-2282	-2669	-2683	-2616	-2485	-1840	-2511	-2684	-2701	-3149	-3725	-2723	-2646	-2533
5. **Transmission System Losses** 13/	613	613	609	579	629	685	704	674	627	597	610	596	671	659	637	638
6. **Net Step I System Loads (1929)** 14/	20569	20641	20488	18995	20357	22371	22038	21329	19230	17942	20122	19144	21366	21926	20570	20701
7. **Step I Coordinated Thermal Installations** 15/																
a) Columbia Generating Station (CGS)	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	355	167	1000	877	896
b) Generic Thermal Installations	8963	8949	9030	8978	8927	8946	8908	8905	7970	7469	7388	6026	8433	8886	8446	8523
c) ...Total	9963	9949	10030	9978	9927	9946	9908	9905	8970	8469	8388	6381	8600	9886	9322	9418
8. **Step I Hydro Load (1929 water)** 16/	10606	10692	10459	9017	10430	12425	12130	11424	10260	9473	11734	12763	12766	12040	11248	11283
a) Hydro Maintenance from WB04	30	25	9	9	4	0	0	0	5	7	8	20	14	49	12	11
b) Coord. Hydro Model Load(1929) 17/	11138	11167	11025	9958	11333	13369	13076	11902	10967	10241	12475	13493	14080	12725	12039	12107
c) Coord. Hydro Load Shape(1929) 18/	92.5%	92.8%	91.6%	82.7%	94.1%	111.0%	108.6%	98.9%	91.1%	85.1%	103.6%	112.1%	117.0%	105.7%	100.0%	

Notes:

1/ Step I Loads and Resources for the Step I System as defined by Treaty Annex B-7 and clarified by the 1988 Entity Agreements.
2/ The Step I critical period is the 42.5 months beginning 16 August 1928 and ending 29 February 1932.
3/ Draft BPA 2004 White Book total regional firm load estimate on April 21, 2005, which includes estimated Coulee pumping and Idaho loads served by Utah Power & Light.
4/ Annex B requires exclusion of Idaho load (and corresponding import) from area served by Utah Power Light in 1964.
5/ Coulee pumping loads and flows in the WB04 were updated based on Feb. 1, 2005, PNCA data submittal.
6/ White Book exports include Firm Seasonal Exchanges, Flow-Through Transfers, Plant Sales, and an estimate of the Canadian Entitlement.
7/ Includes uniform export of 1/2 Canadian Entitlement, 1/2 remained in region.
8/ Added Seasonal Exchange which balances annually. See lines 2(d) and 3(d).
9/ Added thermal export to balance difference between thermal import and equivalent thermal installation based on generic annual shape.
10/ White Book Imports include coordinated thermal installations, seasonal & capacity exchanges, flow-through-transfers, and Skagit Treaty power.
11/ Imports supported by coordinated thermal installations are excluded, to be replaced by a portion of the Generic Thermal Installations. Line 2e balances annual shape difference.
12/ Wind resources based on Feb.2005 BPA forecast of 2011 regional wind resources installed capacity times average Jan.2002 thru Feb.2005 BPA actual wind generation plant factors.
13/ Transmission losses are 2.67% of all resources including imports.
14/ Line 1(d)+ line 2(i) + line 3(f) + line 4(f) + line 5.
15/ Thermal installations are CGS, plus a generic thermal installation, that together with Step I Hydro resources meet the Step 1 System load.
16/ Step I Hydro load for U.S. projects located at or upstream of Bonneville Dam (except hydro independents), line 6 minus line 7(c).
17/ The Coordinated Hydro Model Load is the Step I Hydro Load plus Non-Step I Coordinated Hydro and hydro maintenance, lines 8 + 8a - 4(b).
18/ The Coordination Hydro Model Load Shape shows the net effect of loads and nonhydro resources on the coordinated system hydro resources.

Table 1B
2010-11 ASSURED OPERATING PLAN
DETERMINATION OF FIRM PEAK HYDRO LOADS FOR STEP I STUDIES 1/
(MW)

	Aug15	Aug31	Sept	Oct	Nov	Dec	Jan	Feb	March	Apr15	Apr30	May	June	July
1. Pacific Northwest Area (PNWA) Firm Load														
a) White Book Regional Firm Load	28152	28132	26611	28567	31309	33953	34860	33477	30670	28336	28394	27978	28380	28955
b) Exclude 57% of UPL's Idaho load	-328	-328	-286	-255	-250	-255	-244	-250	-253	-247	-247	-283	-363	-385
c) Remove Federal Peak Diversity 1/	-870	-865	-846	-873	-771	-573	-601	-582	-773	-728	-735	-823	-847	-867
d) Updates to Coulee pumping forec.	-60	-22	48	-104	0	0	0	0	-10	-39	-68	27	-7	-21
e) ....Total PNWA Firm Loads	26894	26917	25527	27335	30288	33125	34015	32645	29634	27322	27344	26899	27163	27682
f) Monthly Load Factors in Percent	79.01	78.85	78.65	74.51	74.02	74.19	73.52	73.15	74.93	77.31	77.36	76.92	77.67	78.66
2. Flows-Out of firm power from PNWA														
a) WB04 Exports	1978	1978	1974	1889	1817	1828	1825	1825	1818	1831	1831	1744	1981	1989
b) Remove WB04 Canadian Entitle.	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350
c) Add estimated Canadian Entitle.	676	676	676	676	676	676	676	676	676	676	676	676	676	676
d) Added Seasonal Exch. Export	482	471	1474	189	0	0	0	0	0	0	502	454	2604	1502
e) Thermal Install. Used outside region 2/	238	273	-225	-215	-319	-447	-160	-141	-99	-137	-152	-274	-309	-281
f) ... Subtotal for Table 2	2024	2048	2550	1189	824	707	991	1010	1045	1020	1507	1250	3603	2537
g) Remove Plant Sales	-191	-191	-191	-191	-191	-191	-191	-191	-191	-191	-191	-45	-191	-191
h) Remove Flow-through-transfer	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75
i) ... Total	1758	1782	2284	953	588	471	755	774	809	754	1241	1130	3337	2271
3. Flows-In of firm power to PNWA, except from coordinated thermal installations														
a) WB04 Imports	-1136	-1101	-1075	-1063	-1162	-1328	-1092	-1091	-995	-887	-901	-889	-1067	-1068
b) Exclude UP&L imports for 1(b)	328	328	286	255	250	255	244	250	253	247	247	283	363	385
c) Remove Thermal Install Imports	367	332	854	871	960	1083	817	782	694	654	668	667	845	847
d) Add Seasonal Exch. Imports	0	0	0	0	-402	-561	-1695	-1923	-1631	-1651	0	0	0	0
e) Remove Flow-Through-Transfer	75	75	75	45	45	45	45	45	45	75	75	75	75	75
f) ... Total	-366	-366	140	108	-309	-506	-1681	-1937	-1635	-1561	89	137	216	239
4. PNWA Non-Step I Hydro and Non-thermal Resources														
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)	-2509	-2430	-2530	-2466	-2366	-2293	-1503	-1334	-2028	-2046	-2096	-2189	-2352	-2530
c) Miscellaneous resources (Wind)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d) Misc. Resources (NUG small Hydro)	-1386	-1386	-1302	-1197	-1150	-1132	-1112	-1140	-1178	-1333	-1333	-1212	-1478	-1437
e) Misc. Resources (Renewables)	-185	-282	-195	-119	-52	-50	-47	-51	-91	-232	-232	-366	-383	-334
f) ... Total (1937)	-6131	-6126	-5965	-5570	-5201	-5069	-4211	-4189	-5084	-5607	-5664	-5937	-6422	-6417
5. Transmission Losses 3/	905	907	894	909	978	1061	1118	1082	975	900	918	901	983	966
6. Net Step I Firm Loads (1937) 4/	23061	23113	22880	23735	26344	29082	29997	28376	24701	21807	23928	23130	25276	24741
7. Step I Coordinated Thermal Installations														
a) Columbia Generating Station(cgs)	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	0	0	1150
b) Generic Thermal Installations	10459	10463	10632	10676	10447	10440	10612	10448	9886	8833	8830	7565	9857	10466
c) ...Total	11609	11613	11782	11826	11597	11590	11762	11598	11036	9983	9980	7565	9857	11616
8. Step I Hydro Load (1937) 5/	11452	11500	11099	11908	14747	17492	18235	16777	13665	11824	13948	15565	15419	13125
a) Hydro Maintenance	4595	4032	3787	3208	2935	2037	1561	2286	2626	2751	2483	2360	2202	3720
b) Reserves (11% of 1e and 2i) 6/	3224	3217	3085	3119	3454	3778	3829	3712	3459	3099	3159	3259	3431	3345
b) Coord.Hydro Model Load (1937) 7/	21779	21179	20500	20702	23501	25601	25129	24110	21777	19720	21686	23373	23404	22720

Notes:

1/ Federal peak diversity is a reduction in peak load to reflect the fact that not all peak loads occur simultaneously across the region.

2/ Export or import to balance difference between excluded thermal imports and generic thermal installation. This concept will be reexamined in AOP12.

3/ Transmission losses are 3.2% of peak load, including absolute value of exports minus imports.

4/ Total Step I Firm Peak Load is the sum of lines 1c + 2i + 3f + 4f + 5.

5/ Step I hydro load = line 6 minus line 7c.

6/ Reserves are same percent of total load, including exports, as WB04 (approximately 11%). This will be reexamined in AOP12.

7/ Coordinated hydro model load = Line 8, plus line 8a, minus line 4b.

TABLE 2

2010-11 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 7(c)	9963	9949	10030	9978	9927	9946	9908	9905	8970	8469	8388	6381	8600	9886	9322.5	9418.4
2. DISPLACEABLE THERMAL RESOURCES																
a) Min.Generation as % of Thermal Inst.	223	223	225	224	222	223	222	222	198	186	184	150	210	221	210.3	212.2
b) Net Displaceable Thermal Resources	**9739**	**9727**	**9805**	**9755**	**9704**	**9723**	**9686**	**9683**	**8772**	**8283**	**8204**	**6231**	**8390**	**9665**	**9112.2**	**9206.2**
3. SYSTEM SALES																
a) Flows-Out (Table 1A, Line 2(f))	1356	1372	2370	972	714	627	858	897	879	871	1339	1146	3611	2505	1419.2	1369.5
b) Exclude Firm Seasonal Exchanges	-28	-28	-39	-14	0	0	0	0	0	0	0	-27	-67	-39	-17.9	-16.7
c) Exclude Added Seasonal Exchanges	-482	-471	-1474	-189	0	0	0	0	0	0	-502	-454	-2604	-1502	-578.5	-534.4
d) Exclude Plant Sales	-173	-173	-173	-173	-173	-173	-173	-173	-173	-173	-165	-36	-173	-173	-161.0	-162.9
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	-269	-269	-269	-269	-269	-269	-269	-269	-269	-269	-269	-269	-269	-269	-269.0	-269.0
g) ...Total System Sales	**328**	**356**	**340**	**283**	**227**	**140**	**371**	**410**	**392**	**354**	**329**	**285**	**423**	**446**	**332.8**	**327.6**
h) Uniform Average Annual System Sales	333	333	333	333	333	333	333	333	333	333	333	333	333	333	332.8	332.8
4. THERMAL DISPLACEMENT MARKET	**9407**	**9394**	**9472**	**9422**	**9372**	**9390**	**9354**	**9350**	**8439**	**7950**	**7872**	**5898**	**8058**	**9332**	**8779.4**	**8873.4**

Notes:

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

3a Flows-Out include firm seasonal exchange exports; added export to flatten thermal import, plant sales, flow-through-transfers, and Canadian Entitlement Exports.

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

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

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

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.

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

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).

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

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
2010-11 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	21249	96.44	26894	79.01	9963	17652.2	7689.7	15089.4	5126.8	Aug. 1-15
Aug. 16-31	21225	96.33	26917	78.85	9949	17632.3	7682.9	15072.3	5122.9	Aug. 16-31
September	20077	91.12	25527	78.65	10030	16678.5	6648.7	14257.0	4227.2	September
October	20367	92.44	27335	74.51	9978	16919.5	6941.2	14463.0	4484.8	October
November	22419	101.75	30288	74.02	9927	18624.5	8697.9	15920.5	5993.9	November
December	24574	111.53	33125	74.19	9946	20414.5	10468.6	17450.6	7504.7	December
January	25007	113.50	34015	73.52	9908	20774.3	10866.0	17758.1	7849.8	January
February	23880	108.38	32645	73.15	9905	19838.2	9933.5	16958.0	7053.2	February
March	22206	100.78	29634	74.93	8970	18447.2	9477.2	15768.9	6799.0	March
April 1-15	21122	95.86	27322	77.31	8469	17546.6	9077.7	14999.1	6530.2	April 1-15
April 16-30	21153	96.00	27344	77.36	8388	17572.4	9183.9	15021.1	6632.6	April 16-30
May	20691	93.91	26899	76.92	6381	17188.7	10807.7	14693.2	8312.1	May
June	21097	95.75	27163	77.67	8600	17526.0	8925.6	14981.5	6381.0	June
July	21775	98.83	27682	78.66	9886	18089.2	8202.8	15462.9	5576.5	July
Annual Avg. 7/ =	22033.0	100.00		76.05	9322.5	18303.7	8981.3	15646.3	6323.8	Annual Avg
SI CP avg(42.5) =	22120.3			**75.89**	9418.4					<==Au2-Feb
S2 CP avg(20) =	22204.5				9448.0	18446.2	8998.2			<==Sep-Ap30
S3 CP avg(5.5) =	23394.2				9612.8			16612.9	7000.1	<==Nov-Ap15
						Input 5/=	**8998.2**	Input 6/=	**7000.1**	
August 1-31	21236.4	96.4	26917.4	78.93	9955.7	17641.9	7686.2	15080.6	5124.8	Aug. 1-31
April 1-30	21137.1	95.9	27343.6	77.33	8428.7	17559.5	9130.8	15010.1	6581.4	Apr. 1-30

Notes:

1/ The PNW Area load does not include the exports, but does include pumping. The computation of the Step II/III load shape uses this load.

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 2010-11 operating year. The critical period (CP) averages are for the historic water years.

TABLE 4
(English Units)
SUMMARY OF POWER REGULATIONS
FROM 2010-11 ASSURED OPERATING PLAN

	BASIC DATA		STEP I			STEP II				STEP III			
	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE kaf	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE kaf	JANUARY 1945 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE kaf	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW
1. HYDRO RESOURCES													
a) CANADIAN STORAGE													
Mica			7000			7000							
Arrow			7100			7100							
Duncan			1400			1400							
Subtotal			15500			15500							
b) BASE SYSTEM													
Hungry Horse	4	428	3072	279	101	3008	167	115	104	3008	330	238	104
Kerr	3	160	1219	178	124	1219	175	112	129	1219	174	152	122
Thompson Falls	6	85	0	85	56	0	85	52	58	0	85	66	57
Noxon Rapids	5	554	231	524	148	0	528	130	197	0	528	175	196
Cabinet Gorge	4	239	0	276	108	0	276	96	128	0	276	121	127
Albeni Falls	3	50	1155	21	23	1155	20	22	21	1155	12	16	19
Box Canyon	4	74	0	71	46	0	70	44	48	0	69	57	47
Grand Coulee	24+3SS	6684	5185	6365	2056	5072	6364	1845	2398	5072	5703	1223	2291
Chief Joseph	27	2535	0	2535	1066	0	2535	968	1307	0	2535	701	1234
Wells	10	840	0	840	420	0	840	388	490	0	840	287	441
Chelan	2	54	677	51	38	676	51	37	44	676	51	51	43
Rocky Reach	11	1267	0	1267	573	0	1267	529	693	0	1267	384	643
Rock Island	18	513	0	547	263	0	547	246	314	0	547	182	289
Wanapum	10	986	0	986	517	0	986	479	605	0	986	338	536
Priest Rapids	10	912	0	912	508	0	912	474	576	0	912	344	507
Brownlee	5	675	975	675	243	974	675	301	318	974	675	263	317
Oxbow	4	220	0	220	101	0	220	126	130	0	220	116	130
Ice Harbor	6	693	0	693	215	0	693	231	303	0	693	163	303
McNary	14	1127	0	1127	626	0	1127	602	770	0	1127	442	716
John Day	16	2484	535	2484	942	0	2484	918	1254	0	2484	683	1214
The Dalles	22+2F	2074	0	2074	750	0	2074	732	994	0	2074	564	970
Bonneville	18+2F	1088	0	1047	566	0	1047	550	682	0	1047	432	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 System 1/		23742	29445	23255	9490	28500	23142	8998	11565	13000	22634	7000	10945
c) ADDITIONAL STEP I PROJECTS						NOT APPLICABLE TO STEP II & III							
Libby	5	600	4980	536	199								
Boundary	6	1055	0	855	367								
Spokane River Plants 2/	24	173	104	169	98								
Hells Canyon	3	450	0	379	199								
Dworshak	3	450	2015	445	157								
Lower Granite	6	932	0	930	217								
Little Goose	6	932	0	928	213								
Lower Monumental	6	932	0	923	218								
Pelton, Rereg., & RB	7	423	274	419	136								
Total added Step I		5947	7373	5583	1804								
2. THERMAL INSTALLATIONS 3/				11762	9418		11762	9448	9322		11762	9613	9322
3. HYDRO MAINT. & PEAK RESERVES 4/				-5390	-11		-4302	0	0		-3825	0	0
4. TOTAL RESOURCES (1b + 1c + 2 + 3)				35210	20701		30601	18446	20887		30571	16613	20268
5. STEP I, II, & III SYSTEM LOADS 5/				29997	20701		28258	18446	18304		24155	16613	15646
6. SURPLUS (4 - 5)				5213	0		2344	0	2583		6416	0	4622
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		11-41			11-42				11-13			

Notes

1/ The above totals may not exactly equal the sum of the above values due to rounding. The total Base System Storage for Steps I and II includes Canadian storage.

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

3/ From Tables 1 and 3.

4/ Step I peak hydro maintenance and reserves are from Table 1b, lines 8a & 8b. Steps II & III Peak Reserves & Maintenance are based on same percent as WB04, i.e. approximately 11% of load for reserves and 5.1% of hydro capability for maintenance. Hydro maintenance energy losses are not included in Steps II & III. Energy reserves for thermal installations are included in the thermal installation energy forecast.

5/ Step I energy load from Table 1A, line 6, and January peak load from Table 1B, line 6. Steps II & III energy load from Table 3. Steps II & III peak loads are equal to Steps II and III January energy load divided by the PNWA January load factor from Table 3.

TABLE 4M
(Metric Units)
SUMMARY OF POWER REGULATIONS
FROM 2010-11 ASSURED OPERATING PLAN

	BASIC DATA		STEP I			STEP II				STEP III 4/			
	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE hm^3	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE hm^3	JANUARY 1945 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE hm^3	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW
1. HYDRO RESOURCES													
a) CANADIAN STORAGE													
Mica			8635			8635							
Arrow			8758			8758							
Duncan			1727			1727							
Subtotal			19119			19119							
b) BASE SYSTEM													
Hungry Horse	4	428	3789	279	101	3710	167	115	104	3710	330	238	104
Kerr	3	160	1504	178	124	1504	175	112	129	1504	174	152	122
Thompson Falls	6	85	0	85	56	0	85	52	58	0	85	66	57
Noxon Rapids	5	554	285	524	148	0	528	130	197	0	528	175	196
Cabinet Gorge	4	239	0	276	108	0	276	96	128	0	276	121	127
Albeni Falls	3	50	1425	21	23	1425	20	22	21	1425	12	16	19
Box Canyon	4	74	0	71	46	0	70	44	48	0	69	57	47
Grand Coulee	24+3SS	6684	6396	6365	2056	6256	6364	1845	2398	6256	5703	1223	2291
Chief Joseph	27	2535	0	2535	1066	0	2535	968	1307	0	2535	701	1234
Wells	10	840	0	840	420	0	840	388	490	0	840	287	441
Chelan	2	54	835	51	38	834	51	37	44	834	51	51	43
Rocky Reach	11	1267	0	1267	573	0	1267	529	693	0	1267	384	643
Rock Island	18	513	0	547	263	0	547	246	314	0	547	182	289
Wanapum	10	986	0	986	517	0	986	479	605	0	986	338	536
Priest Rapids	10	912	0	912	508	0	912	474	576	0	912	344	507
Brownlee	5	675	1203	675	243	1201	675	301	318	1201	675	263	317
Oxbow	4	220	0	220	101	0	220	126	130	0	220	116	130
Ice Harbor	6	693	0	693	215	0	693	231	303	0	693	163	303
McNary	14	1127	0	1127	626	0	1127	602	770	0	1127	442	716
John Day	16	2484	660	2484	942	0	2484	918	1254	0	2484	683	1214
The Dalles	22+2F	2074	0	2074	750	0	2074	732	994	0	2074	564	970
Bonneville	18+2F	1088	0	1047	566	0	1047	550	682	0	1047	432	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 System 1/		23742	36320	23255	9490	35155	23142	8998	11565	16036	22634	7000	10945
c) ADDITIONAL STEP I PROJECTS						NOT APPLICABLE TO STEP II & III							
Libby	5	600	6143	536	199								
Boundary	6	1055	0	855	367								
Spokane River Plants 2/	24	173	128	169	98								
Hells Canyon	3	450	0	379	199								
Dworshak	3	450	2486	445	157								
Lower Granite	6	932	0	930	217								
Little Goose	6	932	0	928	213								
Lower Monumental	6	932	0	923	218								
Pelton, Rereg., & RB	7	423	338	419	136								
Total added step 1		5947	9095	5583	1804								
2. THERMAL INSTALLATIONS 3/				11762	9418		11762	9448	9322		11762	9613	9322
3. HYDRO MAINT. & PEAK RESERVES 4/				-5390	-11		-4302	0	0		-3825	0	0
4. TOTAL RESOURCES (1b + 1c + 2 + 3)				35210	20701		30601	18446	20887		30571	16613	20268
5. STEP I, II, & III SYSTEM LOADS 5/				29997	20701		28258	18446	18304		24155	16613	15646
6. SURPLUS (4 - 5)				5213	0		2344	0	2583		6416	0	4622
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			11-41			11-42				11-13		

Notes

1/ The above totals may not exactly equal the sum of the above values due to rounding. The total Base System Storage for Steps I and II includes Canadian storage.

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

3/ From Tables 1 and 3

4/ Step I peak hydro maintenance and reserves are from Table 1b, lines 8a & 8b. Steps II & III Peak Reserves & Maintenance are based on same percent as WB04, i.e. approximately 11% of load for reserves and 5.1% of hydro capability for maintenance. Hydro maintenance energy losses are not included in Steps II & III. Energy reserves for thermal installations are included in the thermal installation energy forecast.

5/ Step I energy load from Table 1A, line 6, and January peak load from Table 1B, line 6. Steps II & III energy load from Table 3. Steps II & III peak loads are equal to Steps II and III January energy load divided by Step I January load factor from Table 3.

TABLE 5
(English & Metric Units)
COMPUTATION OF CANADIAN ENTITLEMENT FOR
2010-11 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S. (From 11-42)
B. Optimum Power Generation in the U.S. Only (From 11-12)
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 11-22). 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/	8998.2	8998.2	8963.7
Step III - Critical Period Average Generation 2/	7000.1	7000.1	7000.1
Gain Due to Canadian Storage	1998.1	1998.1	1963.6
Average Critical Period Load Factor in percent 3/	75.89	75.89	75.89
Dependable Capacity Gain 4/	2632.9	2632.9	2587.4
Canadian Share of Dependable Capacity 5/	1316.4	1316.4	1293.7

Determination of Increase in Average Annual Usable Hydro Energy (aMW)	**ENERGY ENTITLEMENT**		
Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Firm Energy 6/	8981.9	8981.9	8947.7
Thermal Displacement Energy 7/	2414.7	2410.1	2423.0
Remaining Usable Energy 8/	67.2	67.7	70.7
System Average Annual Usable Energy	11463.8	11459.7	11441.4
Step III (without Canadian Storage) 2/			
Firm Energy 6/	6324.3	6324.3	6324.3
Thermal Displacement Energy 7/	3699.3	3699.3	3699.3
Remaining Usable Energy 8/	368.7	368.7	368.7
System Average Annual Usable Energy	10392.3	10392.3	10392.3
Average Annual Usable Energy Gain 9/	1071.5	1067.4	1049.1
Canadian Share of Average Annual Energy Gain 5/	535.7	533.7	524.6

1/ Step II values were obtained from the 11-42, 11-12, and 11-22 studies, respectively.
2/ Step III values were obtained from the 11-13 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

	2006-07	2007-08	2008-09	2009-10	2010-11
AVERAGE PNWA ENERGY LOAD					
Annual Load (MW)	23734.4	24111.7	24495.5	22268.2	22033.0
Annual/January Load (%)	87.4	87.4	87.3	87.5	88.1
Critical Period (CP) Load Factor (%)	75.7	75.8	75.7	73.9	75.9
Annual Firm Exports 1/	867.6	718.7	704.7	639.6	636.7
Annual Firm Surplus (MW) 2/	701.2	798.2	747.3	762.4	578.5
THERMAL INSTALLATIONS (MW) 3/					
January Peak Capability	11946	11856	12417	9756	11762
CP Energy	10587	10819	11228	8891	9418
CP Minimum Generation	231	237	245	196	212
Average Annual System Export Sales	353	255	259	144	333
Average Annual Displaceable Market	9926	10270	10643	8504	8779
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	175663	175663
Step I CP Average	114401	114401	114401	115061	115061
Step II CP Average	101525	101525	101525	101961	101961
Step III CP Average	57184	57184	57184	56558	56558
BASE STREAMFLOWS AT THE DALLES (m^3/s) 4/					
Step I 30-yr. Average Streamflow	5003.64	5003.64	5003.64	4974.22	4974.22
Step I CP Average	3239.47	3239.47	3239.47	3258.17	3258.17
Step II CP Average	2874.87	2874.87	2874.87	2887.22	2887.22
Step III CP Average	1619.26	1619.26	1619.27	1601.55	1601.55
CAPACITY BENEFITS (MW)					
Step II CP Generation	9020.0	9015.2	9018.7	9018.1	8998.2
Step III CP Generation	7135.1	7134.3	7132.2	7020.8	7000.1
Step II Gain over Step III	1884.9	1880.9	1886.5	1997.3	1998.1
CANADIAN ENTITLEMENT	1244.3	1240.9	1245.2	1352.3	1316.4
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	8928.2	8870.6	8921.2	8907.7	8981.9
Step II Thermal Displacement	2512.3	2586.5	2558.9	2444.1	2414.7
Step II Remaining Usable Secondary	41.2	34.6	25.4	87.6	67.2
Step II System Average Annual Usable	11481.7	11491.7	11505.5	11439.4	11463.8
Step III Annual Firm	6286.9	6150.8	6243.5	6174.1	6324.3
Step III Thermal Displacement	3922.6	4094.4	4084.5	3707.8	3699.3
Step III Remaining Usable Secondary	295.2	280.8	247.7	423.2	368.7
Step III System Average Annual Average	10504.7	10526.0	10575.7	10305.1	10392.3
CANADIAN ENTITLEMENT	488.5	482.8	464.9	567.1	535.7
Change due to Mica Reoperation	1.5	1.7	1.9	3.9	2.0
ENTITLEMENT in Sales Agreement	0.0	0.0	0.0	0.0	0.0
STEP II PEAK CAPABILITY (MW)	32607	32501	33008	30530	30601
STEP II PEAK LOAD (MW)	30550	30884	31564	28996	28258
STEP III PEAK CAPABILITY (MW)	32488	32381	32882	30371	30571
STEP III PEAK LOAD (MW)	24874	25063	25758	23142	24155

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)
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.
2010-11	482 Aug 15, 471 Aug 31, 1474 Sep, 189 Oct, 502 April 30, 454 May, 2604 June, and 1502 July.

3. 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 DDPB with an adjustment for the Grand Coulee pumping and return flow. Beginning with the 2009-10 DDPB, the updated 2000 level modified flows and updated the Grand Coulee pumping were used. The 2009-10 included adjusted return flow; while 2010-11 did not.

CHART 1
2010-11 DDBP STUDIES
DURATION CURVES OF 30 YEARS MONTHLY HYDRO GENERATION (aMW)