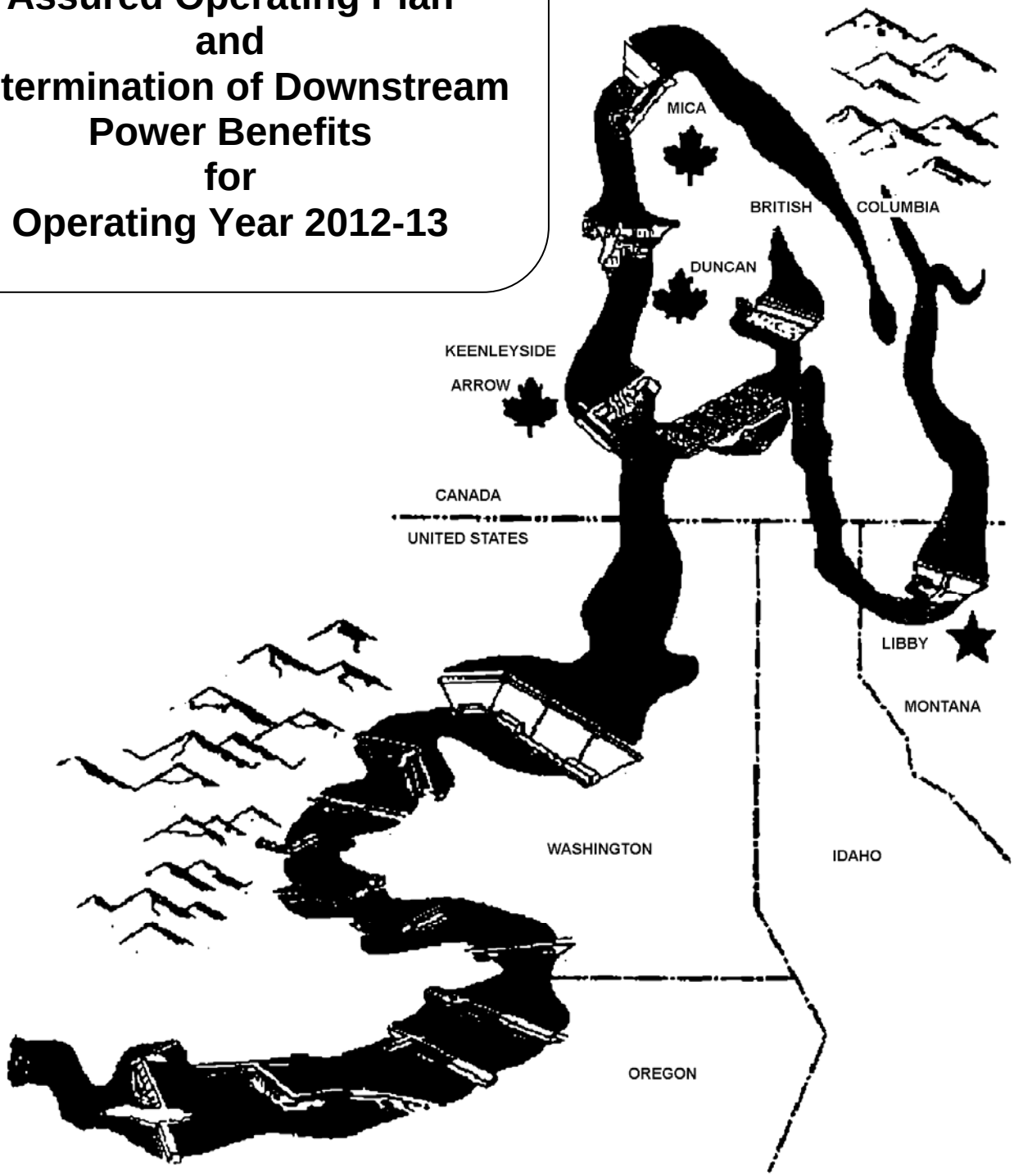
COLUMBIA RIVER TREATY
Assured Operating Plan
and
Determination of Downstream Power Benefits
for
Operating Year 2012-13



Columbia River Treaty Operating Committee January 2008

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COLUMBIA RIVER TREATY ENTITY AGREEMENT ON THE ASSURED OPERATING PLAN AND DETERMINATION OF DOWNSTREAM POWER BENEFITS FOR THE 2012-13 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 2012-13" and "Columbia River Treaty Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2012-13," both dated January 2008, shall be the Assured Operating Plan and Determination of Downstream Power Benefits for the 2012-13 Operating Year.

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

Executed for the Canadian Entity this 18 day of February, 2008.

By: _____
Robert G. Elton
Chair

Executed for the United States Entity this 12th day of February, 2008.

By: _____
Stephen J. Wright
Chairman

By: _____
COL Steven R. Miles
Member

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COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
FOR OPERATING YEAR 2012-13

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HYDROELECTRIC OPERATING PLAN
ASSURED OPERATING PLAN
FOR OPERATING YEAR 2012-13

January 2008

1. Introduction

The "Treaty between Canada and the United States of America relating to the cooperative development of the water resources of the Columbia River Basin" (Treaty), dated 17 January 1961, 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 2012-13 AOP (AOP13) 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 Treaty, the "Protocol - Annex to Exchange of Notes, Dated January 22, 1964 Between the Governments of Canada And the United States Regarding the Columbia River Treaty" (Protocol), and 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, and except for changes noted below, 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 Stream flows.

The POP is based on criteria contained in Annex A and Annex B of the Treaty, the Protocol, and the Columbia River Treaty Flood Control Operating Plan (FCOP), dated May 2003. For this AOP, the Entities have agreed to use the three streamline methods defined in Appendix 6 of the POP together with the following assumptions and modifications:

  - "Forecasting Loads and Resources" for determining the thermal installations with a modification to allocate available uncommitted PNWA

resources and available uncommitted imports from Canada and California, together with a seasonal exchange, to balance the White Book deficit, as described in Subsection 7(b) of this document;

- "Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage" based on the AOP12 US and Joint Optimum Step I System Regulation studies, as explained in Subsection 2(a); and

- "Monthly Hydro Energy Reshaping for Steps II and III 30-year System Regulation Studies", as described in Subsection 6(f) of the DDPB12.

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 (AOP12-41) System Regulation Study.[1]

This AOP includes both metric (International Standard) and English units.[2] 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 2012-13 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. As part of the Streamline Method, the Entities have agreed to adjust the estimated added

seasonal exchange imports and exports so that the Step I System regulated hydro loads are similar to the AOP12. With the same regulated hydro load, the AOP12 Step I System Regulation Studies can serve as the basis for the AOP13.

In accordance with Protocol VIII, the AOP13 is based on a 30-year stream flow 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[3] 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 AOP13, 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 1.5 aMW increase in the Canadian Entitlement for average annual usable energy and no change in the dependable capacity compared to the operation for optimum generation in the USA alone. (See Table 5 from the DDPB12, columns A and B.)

Since there is no reduction in entitlement, the Entities have determined in Section 3 of the 2012-13 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 2012-13 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 project 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 any of the lower numbered CRC's, and past practice was for the hydro regulation model to lower the storage amounts in the higher numbered CRC's at

all projects as needed to eliminate the crossover. For the Canadian Treaty projects, this adjustment is applied 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, 5, and 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 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 stream flows at The Dalles, Oregon, during the 30-year (1928-58) stream flow 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 31 July based on the 95% confidence forecasted inflow volume. The upstream storage refill requirements and PDRs 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 forecast inflows. The PDRs 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 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 values for 98.68 km^3 and 135.69 km^3 (80 Maf and 110 Maf), respectively, were used. For AOP13, as in the AOP12, the VRC Lower Limit (VRCLL) was applied as a fixed rule curve for Grand Coulee only.

Tables 4-6 illustrate the range of VRCs for Mica, Arrow, and Duncan for the 30-year stream flow period. In actual operation in 2012-13, 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 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 stream flows at The Dalles during the 30-year stream flow period. The ORCLLs for Mica, Arrow, and Duncan are shown in Tables 4, 5, and 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 stream flow period are shown in Tables 7, 8, and 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 (limited by the VRCLL) is lower, then the VRC 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 stream flow period are included in Table 10 to illustrate the probable future range of these curves based on historical water conditions.

4. Operating Rules

Under the Streamline Procedure "Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage", the AOP12-41 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 stream flow 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 Appendix A.

The following rules and other operating criteria included in the AOP12-41 System Regulation Study will apply to the operation of Canadian Treaty Storage in the 2012-13 Operating Year, subject to the provisions under Section 5.

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 project 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 AOP13 is not intended to set a 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 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 Arrow Project Operating Criteria (APOC).

The APOC is shown in Table 1.1a and consists of maximum storage limits, maximum outflow limits and minimum outflow limits at Arrow. The maximum storage limits apply from February to June depending on the forecast for The Dalles residual unregulated runoff for the current month through July. The maximum and minimum outflow limits apply under all water conditions, subject to flood control requirements and a maximum combined draft of 17.39 km^3 (14.1 Maf) at Mica + Arrow, respectively. In no circumstance shall the minimum outflow be reduced below the Treaty specified minimum of 142 m^3/s (5,000 cfs).

The implementation of the APOC storage limits in the Detailed Operating Plan 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 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 AOP12 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 2012-13 DOP (DOP13) will reflect the latest available load, resource, and other pertinent data to the extent the Entities agree that this 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 DOP13. Failing agreement on updating the data and/or criteria, the DOP13 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 2012-13 Operating Year shall be guided by the DOP13.

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 stream flow 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 2012-13."

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.[4] This arrangement covers the full 1 August 2012 through

31 July 2013 period covered by this AOP, and includes transmission losses and scheduling guidelines for delivery of the Canadian Entitlement.

7. Summary of Changes from the 2011-12 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) Pacific Northwest Area (PNWA) Firm Load

Loads for the AOP13 are based on Bonneville Power Administration's (BPA) March 2007 White Book (WB07)[5] expected load forecast. The WB07 forecast for the 2012-13 regional firm load is 23,079 annual aMW, and is based on a 1.45% annual load growth from the 2012 to 2013 operating year. This forecast for the AOP13 is 913 aMW (4.1%) higher than the WB06 forecast used in the AOP12. This increase is primarily due to additional industrial load in the PNWA and to the correction of some previously under-reported utility loads. As there were only minor changes to the Idaho portion of the Utah Power & Light load and to the Coulee pumping requirements, the net PNWA firm load increased by 904 annual aMW (4.2%) from the AOP12 to AOP13.

The average critical period load factor decreased from 76.07% in AOP12 (WB06) to 74.85% in AOP13 (WB07). This was mainly due to changes in the peak load forecast.

b) Flows of Power at Points of Interconnection

The Step I System Load includes the net effect of flows of power at points of interconnection which are all imports and exports, except those classified as thermal installations, plant sales, and flow-through-transfers.

- For the AOP13, a new procedure was developed to estimate the amount of Canadian Entitlement energy and uncommitted resources that would be assumed to serve load in the PNWA. This procedure assumes all of the Canadian Entitlement is returned to Canada, but that same power is then available as an uncommitted import for the PNWA. The procedure uses a two-step pro rata approach to allocate uncommitted PNWA resources (including unreported combustion turbine (CT) capability) and available uncommitted imports from Canada and California, together with a seasonal exchange, to eliminate WB surpluses and deficits calculated without the uncommitted resources. The first step reduces or eliminates the monthly deficits based on the proportion of available uncommitted PNWA resources (without unreported CT capability) and available Canadian imports. Any remaining deficits are then allocated based on the proportion of available unreported CT capability and assumed available California imports. The resulting amount of allocated imports are included in the Step I load/resource balance. This procedure results in an estimated Canadian import of about 53% (265 annual aMW) of the assumed available Canadian Entitlement (500

annual aMW). Compared to AOP12, this is equivalent to a 140 annual aMW increase in Entitlement energy remaining in the U.S.

- The estimated Canadian Entitlement included in export loads was 500 average annual MW of energy and 1350 MW of capacity. The amount computed for the DDPB13 is 504.5 average annual MW of energy and 1320.8 MW of capacity. Iterative studies to update the Canadian Entitlement assumed in the load estimate (see DDPB Table 1) were not performed because the effect on the amount of thermal installations would not significantly affect the results of the studies.
- Compared to the AOP12, Flows-Out (exports that are mostly to the southwest but also include the Entitlement) increased by 175 annual aMW, and Flows-In (imports) increased by 334 annual aMW. These differences are primarily due to changes in WB imports/exports and in the manner in which the amount of Canadian Entitlement returned to the PNWA is accounted for.

c) Non-Step I Hydro and Other Non-Thermal Resources

The Step I System Load is reduced by Hydro Independent generation, Non-Step I Coordinated Hydro, and Miscellaneous Non-Thermal Resources. For the AOP13, these resources have increased by 223 annual aMW over the AOP12. This is primarily due to the addition of several large wind projects and other renewable resources.

d) Thermal Installations

Because of increasing difficulty in forecasting Thermal Installations, the Entities again used the Streamline Procedure for "Loads and Resources" for determining Thermal Installations, as used in the 2006-07 and all later AOPs. The procedure includes the Columbia Generating Station (CGS, formerly called Washington Public Power Supply System #2 nuclear power plant) plus one generic Thermal Installation, sized as needed to balance loads and resources in the critical period. The CGS annual average generation decreased by 122 aMW from AOP12 to AOP13, due to the inclusion of a maintenance outage. The total thermal installations increased by 572 annual aMW from AOP12 to AOP13 due to a combination of all changes in loads and resources explained above.

e) Hydro Project Modified Stream flows

The unregulated base stream flows for the Step I System Regulation Studies were the same as the AOP12 studies which were based on the 2000 Level Modified Stream flows with updates to Grand Coulee pumping.

f) Hydro Project Rule Curves

In accordance with the Streamline Procedure "Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage", the AOP13 System Regulation studies use the same hydro project rule curves as the AOP12. Some notable assumptions include:

- The use of a fixed VRCLL at Grand Coulee only, equal to the ORCLL for January and February, and based on historic minimum elevations for firm power operation for March to June (1225 ft for March-April, 1240 ft for May and 1285 ft for June).

- 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 use of the AOP12, 30-year URC data developed by the Corps of Engineers.

- Hedges (also called forecast errors) for Mica, Arrow, Duncan, Libby, and Dworshak were updated from new studies, with large increases at Canadian projects and Dworshak.

g) Other Hydro Project Operating Procedures, Constraints, and Plant Data

In accordance with the Streamline Procedure "Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage", the AOP13 hydro project operating procedures, constraints and plant data are the same as in the AOP12.

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. Some notable assumptions include:

- Brownlee minimum flow requirements are 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, and a target operation June through September to obtain uniform outflows July through August.

- Grand Coulee, which is normally drafted 0.61 m (2 ft) at the beginning of the critical period, is held full through August 31, 1928 to avoid a surplus.

- The 30-year storage operation at Mossyrock, Cushman 1, Alder, Swift #1, Merwin, Yale, and Timothy was set to a fixed operation (first coded) from the 2006 AOP because they are no longer coordinated resources in PNCA Planning. Although included in the Step I hydroregulation model, these projects are now essentially the same as a hydro-independent project.

- Ross and Gorge operating data were inadvertently not fully updated to the 2006 PNCA data submittal. The Operating Committee expects to update this data in the next full AOP.

- Hydro-independent projects are not yet updated for the 2000 Modified Flows.

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1 "BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 12-41," dated 20 February 2007.

2 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).

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

4 "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.

5 "2007 Pacific Northwest Loads & Resources Study, Operating Years 2008 through 2017", dated March 2007, and expected to be published early in 2008.

TABLE 1
(English Units)
MICA PROJECT OPERATING CRITERIA
2012-13 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	3,300 - FULL	-	3,364.2	-	34,000	15,000
	2,170 - 3,300	25,000	-	0	-	15,000
	1,500 - 2,170	20,000	-	0	-	15,000
	0 - 1,500	32,000	-	0		15,000
August 16-31	2,710 - FULL	-	3,529.2	-	34,000	15,000
	1,950 - 2,710	25,000	-	0	-	15,000
	0 - 1,950	32,000	-	0	-	15,000
September	3,530 - FULL	-	3,529.2	-	34,000	10,000
	3,400 - 3,530	24,000	-	0	-	10,000
	2,800 - 3,400	27,000	-	0	-	10,000
	0 - 2,800	32,000	-	0	-	10,000
October	3,440 - FULL	-	3,428.4	-	34,000	10,000
	2,600 - 3,440	19,000	-	0	-	10,000
	2,000 - 2,600	22,000	-	0	-	10,000
	0 - 2,000	32,000	-	0	-	10,000
November	3,340 - FULL	21,000	-	0	-	10,000
	3,130 - 3,340	19,000	-	0	-	10,000
	420 - 3,130	25,000	-	0	-	10,000
	0 - 420	32,000	-	0	-	10,000
December	2,740 - FULL	25,000	-	204.1	-	10,000
	1,800 - 2,740	22,000	-	204.1	-	10,000
	300 - 1,800	27,000	-	204.1	-	10,000
	0 - 300	32,000	-	204.1	-	10,000
January	2,640 - FULL	24,000	-	204.1	-	12,000
	2,180 - 2,640	27,000	-	204.1	-	12,000
	1,350 - 2,180	25,000	-	204.1	-	12,000
	0 - 1,350	29,000	-	204.1	-	12,000
February	1,370 - FULL	21,000	-	0	-	12,000
	900 - 1,370	26,000	-	0	-	12,000
	500 - 900	21,000	-	0	-	12,000
	0 - 500	26,000	-	0	-	12,000
March	800 - FULL	17,000	-	0	-	12,000
	770 - 800	26,000	-	0	-	12,000
	510 - 770	22,000	-	0	-	12,000
	0 - 510	25,000	-	0	-	12,000
April 1-15	890 - FULL	20,000	-	0	-	12,000
	350 - 890	10,000	-	0	-	12,000
	220 - 350	12,000	-	0	-	12,000
	0 - 220	22,000	-	0	-	12,000
April 16-30	570 - FULL	10,000	-	0	-	10,000
	110 - 570	15,000	-	0	-	10,000
	20 - 110	10,000	-	0	-	10,000
	0 - 20	15,000	-	0	-	10,000
May	640 - FULL	8,000	-	0	-	8,000
	520 - 640	12,000	-	0	-	8,000
	220 - 520	8,000	-	0	-	8,000
	0 - 220	10,000		0	-	8,000
June	1,610 - FULL	8,000	-	0	-	8,000
	1,020 - 1,610	10,000	-	0	-	8,000
	810 - 1,020	14,000		0	-	8,000
	0 - 810	18,000	-	0	-	8,000
July	3,180 - FULL	-	3,467.2	-	34,000	10,000
	2,670 - 3,180	-	3,405.2	-	34,000	10,000
	1,160 - 2,670	20,000	-	0	-	10,000
	0 - 1,160	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
DEFINITION
2012-13 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)
August 15 - December	-		URC	-	10,000
January	-		URC	70,000	10,000
February	1 Feb - 31 Jul	≤ 70	URC	60,000	20,000
		>70 to <80	URC to 1800		
		≥ 80	1800		
March	1 Mar - 31 Jul	≤ 65	URC	-	20,000
		>65 to <75	URC to 900		
		≥ 75	900		
April 15	1 Apr - 31 Jul	≤ 61	URC	-	15,000
		>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 2100		
		≥ 70	2100		
June	1 Jun - 31 Jul	≤ 33	URC	-	5,000
		>33 to <35	URC to 3400		
		≥ 35	3400		
July	-		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.

TABLE 1.1b
(English Units)
ARROW PROJECT OPERATING CRITERIA
30 YEAR OPERATING DATA
FOR 2012-13 ASSURED OPERATING PLAN

	AUG15-DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
Maximum Average Monthly Flow Limits (cfs)									
	-	70,000	60,000	-	-	-	-	-	-
Minimum Average Monthly Flow Limits (cfs)									
	10,000	10,000	20,000	20,000	15,000	10,000	10,000	5,000	10,000
End-of-Period Maximum Storage Limits (ksfd)									
1928-29	-	-	URC	URC	URC	URC	URC	3500.3	-
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	2100.0	3400.0	-
1932-33	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1933-34	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1934-35	-	-	1800.0	900.0	900.0	1000.0	URC	3400.0	-
1935-36	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1936-37	-	-	URC	URC	URC	URC	URC	3478.6	-
1937-38	-	-	1800.0	900.0	900.0	1000.0	URC	3400.0	-
1938-39	-	-	1928.8	930.4	1163.2	1241.8	URC	URC	-
1939-40	-	-	1987.4	1202.8	1933.1	1970.2	URC	URC	-
1940-41	-	-	URC	URC	URC	URC	URC	URC	-
1941-42	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1942-43	-	-	1800.0	900.0	900.0	1000.0	2100.0	3400.0	-
1943-44	-	-	URC	URC	URC	URC	URC	URC	-
1944-45	-	-	1852.7	966.9	1024.5	1114.2	URC	3400.0	-
1945-46	-	-	1800.0	900.0	900.0	1000.0	URC	3400.0	-
1946-47	-	-	1800.0	900.0	900.0	1000.0	2100.0	3400.0	-
1947-48	-	-	1800.0	900.0	900.0	1000.0	URC	3400.0	-
1948-49	-	-	1800.0	900.0	900.0	1000.0	2944.2	URC	-
1949-50	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1950-51	-	-	1800.0	900.0	900.0	1000.0	2100.0	3400.0	-
1951-52	-	-	1800.0	900.0	900.0	1000.0	2100.0	3400.0	-
1952-53	-	-	1800.0	900.0	900.0	1000.0	URC	3400.0	-
1953-54	-	-	1800.0	900.0	900.0	1000.0	2100.0	URC	-
1954-55	-	-	1800.0	900.0	900.0	1000.0	URC	URC	-
1955-56	-	-	1800.0	900.0	900.0	1000.0	2100.0	3400.0	-
1956-57	-	-	1800.0	900.0	900.0	1000.0	2100.0	3400.0	-
1957-58	-	-	1800.0	900.0	900.0	1000.0	2100.0	3400.0	-

TABLE 1.1c
APOC IMPLEMENTATION
DISTRIBUTION FACTORS FOR THE DALLES
2012-13 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 DOP13 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)	Month-Jul Volume Runoff (km^3)	The Dalles Volume Runoff (Maf)	The Dalles Volume Runoff (km^3)	Maximum Storage Limit (ksfd)	Maximum Storage Limit (hm^3)
May	1.0000	65.0	80.2	$\leq$ 68	$\leq$ 83.9	URC	URC
June	0.6123	39.8	49.1	$\geq$ 35	$\geq$ 43.2	3400	8318.4

TABLE 2
COMPARISON OF 2012-13 ASSURED OPERATING PLAN
STUDY RESULTS

Study 13-41 provides Optimum Generation in Canada and in the United States.
Study 13-11 provides Optimum Generation in the United States only.

	Study No. 13-41	Study No. 13-11	Net Gain	Weight	Value
1. Firm Energy Capability (aMW)					
U.S. System 1/	11936.0	11935.9	0.1		
Canada 2/, 3/	2952.6	2909.1	43.6		
Total	14888.6	14845.0	43.6	3	130.8
2. Dependable Peaking Capacity (MW)					
U.S. System 4/	29995.9	30018.8	-22.9		
Canada 2/, 5/	5787.5	5745.8	41.7		
Total	35783.4	35764.6	18.8	1	18.8
3. Average Annual Usable Secondary Energy (aMW)					
U.S. System 6/	3100.3	3078.7	21.6		
Canada 2/, 7/	288.5	302.4	-13.9		
Total	3388.8	3381.1	7.7	2	15.4
			Net Change in Value =		165.0

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)
2012 - 13 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	3529.2	3529.2	3522.6	3409.0	3002.9	2274.1	1526.8	783.7	505.1	258.7	173.5	469.0	2114.7	3101.2
1929-30	3396.4	3504.2	3328.0	2470.9	1956.8	1431.0	512.8	160.5	0.0	0.0	220.2	623.7	1169.2	2474.4
1930-31	2862.9	3176.4	3182.0	2452.1	2087.7	1236.3	746.5	67.4	0.0	0.0	0.0	267.4	945.5	2093.9
1931-32	2004.5	1834.3	1157.3	1064.2	612.5	0.0	0.0	0.0						
							ARROW							
1928-29	3579.6	3579.4	3322.8	3032.9	2770.8	2489.7	1532.6	932.1	599.2	685.7	739.2	1666.4	3203.6	3552.9
1929-30	3539.1	3535.9	3001.3	2950.1	2015.1	1460.9	471.2	171.8	0.0	70.0	447.6	1453.4	2562.9	3268.6
1930-31	3369.1	3298.5	2800.1	2730.4	1851.9	1247.5	279.3	144.9	0.0	0.0	1.4	774.7	1820.5	1729.9
1931-32	1778.5	1889.7	1681.5	1129.7	749.7	226.1	2.1	0.0						
							DUNCAN							
1928-29	705.8	705.8	698.8	685.2	621.0	440.2	357.0	259.5	164.8	140.0	151.3	268.8	543.6	675.7
1929-30	675.4	652.1	593.4	590.6	543.1	402.4	219.4	45.1	0.0	1.1	34.2	109.0	315.2	429.6
1930-31	468.3	523.1	581.1	539.2	550.1	333.6	143.3	0.0	0.0	0.2	0.0	157.2	150.8	139.2
1931-32	171.4	96.6	84.6	113.7	69.2	0.0	0.0	0.0						
							COMPOSITE							
1928-29	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3416.4	1975.3	1269.1	1084.4	1064.0	2404.2	5861.9	7329.8
1929-30	7610.9	7692.2	6922.7	6011.6	4515.0	3294.3	1203.4	377.4	0.0	71.1	702.0	2186.1	4047.3	6172.6
1930-31	6700.3	6998.0	6563.2	5721.7	4489.7	2817.4	1169.1	212.3	0.0	0.2	1.4	1199.3	2916.8	3963.0
1931-32	3954.4	3820.6	2923.4	2307.6	1431.4	226.1	2.1	0.0						

Note: These rule curves are input to the AOP 2013 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, AND OPERATING RULE CURVE LOWER LIMITS
2012 - 13 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	51.4	634.3	1236.7	1415.3	1480.6	1497.1	1491.9	1480.4	1487.2	1512.2	1575.4	2352.5	3486.0	3529.2
VARIABLE REFILL CURVES (KSFD)														
1928-29							2759.4	2581.8	2521.5	2513.1	2554.0	3055.4	3353.0	3529.2
1929-30							1737.1	1520.3	1450.3	1459.9	1616.4	2449.2	3069.2	"
1930-31							1994.9	1787.1	1712.6	1700.5	1790.8	2468.2	3143.9	"
1931-32							951.3	750.7	682.8	671.5	788.8	1577.3	2847.6	"
1932-33							857.9	692.6	642.1	628.6	706.3	1476.2	2685.0	"
1933-34							40.5	0.0	0.0	0.0	0.8	1222.2	2936.5	"
1934-35							1238.9	1054.9	1016.6	1023.2	1093.3	1793.7	2796.3	"
1935-36							1084.9	901.4	851.8	838.0	933.0	1803.6	3074.7	"
1936-37							2746.1	2548.0	2472.8	2453.5	2542.5	3067.5	3384.5	"
1937-38							1230.2	1046.3	978.5	971.7	1064.7	1801.5	2939.4	"
1938-39							1705.0	1565.5	1504.9	1518.6	1629.8	2396.6	3348.0	"
1939-40							1493.2	1317.0	1273.8	1281.5	1411.0	2200.0	3110.4	"
1940-41							2180.0	1992.7	1937.7	1945.0	2122.0	2846.5	3366.7	"
1941-42							1749.6	1566.2	1503.0	1487.1	1563.2	2222.1	3128.1	"
1942-43							1867.2	1661.0	1594.8	1578.7	1731.1	2429.0	3177.5	"
1943-44							2851.8	2637.9	2576.3	2566.1	2634.7	3177.2	3524.2	"
1944-45							2628.4	2451.5	2403.8	2404.2	2453.8	2952.8	3398.7	"
1945-46							651.6	437.4	367.8	344.0	435.6	1275.5	2843.5	"
1946-47							765.3	604.8	564.0	562.0	678.8	1536.2	2911.7	"
1947-48							714.2	533.1	477.2	449.0	529.3	1331.7	2798.4	"
1948-49							2410.8	2204.2	2121.3	2104.9	2182.4	2707.6	3529.2	"
1949-50							1069.7	849.1	769.6	746.2	831.0	1552.9	2609.7	"
1950-51							1060.9	888.0	840.5	834.9	948.7	1672.0	2971.2	"
1951-52							1467.7	1252.2	1179.2	1150.1	1231.9	1967.4	3118.5	"
1952-53							1749.0	1551.3	1487.8	1471.6	1531.3	2122.6	3085.5	"
1953-54							624.7	439.3	400.5	390.2	474.1	1247.9	2581.8	"
1954-55							1384.5	1215.0	1168.0	1164.4	1250.9	1893.6	2776.3	"
1955-56							932.9	745.8	678.1	657.2	746.0	1570.0	2885.8	"
1956-57							1101.5	907.1	854.0	845.4	934.8	1656.1	3216.3	"
1957-58							935.2	753.8	707.1	703.9	809.3	1552.9	2978.9	"
DISTRIBUTION FACTORS							0.9750	0.9770	0.9740	0.9812	0.9650	0.7950	0.4950	N/A
FORECAST ERRORS (KSFD)							728.1	521.9	455.3	420.3	420.3	401.5	397.1	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	22350	55100
VARIABLE REFILL CURVES					80	MAF	3000	3000	3000	3000	3000	3000	32000	38000
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	3000	3000	3000	3000	3000	3000	18000	32300
					110	MAF	3000	3000	3000	3000	3000	3000	18000	32300
OPERATING RULE CURVE LOWER LIMITS (KSFD)							279.8	28.5	0.0	0.0				

TABLE 5
(English Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2012 - 13 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	696.5	1488.8	1556.4	1638.0	1718.7	1887.5	3096.6	3579.6	3579.6
VARIABLE REFILL CURVES (KSFD)														
1928-29							3579.6	3479.2	3362.0	3284.8	3402.6	3579.6	3541.1	3579.6
1929-30							2106.2	1826.6	1830.5	1827.7	2128.8	3343.8	3579.6	"
1930-31							2609.4	2301.3	2204.6	2160.3	2363.1	3197.7	3560.1	"
1931-32							0.0	0.0	0.0	0.0	0.0	486.5	2703.8	"
1932-33							"	"	"	"	"	437.3	2592.8	"
1933-34							"	"	"	"	"	867.9	3077.9	"
1934-35							926.5	855.8	965.1	981.2	1156.4	2253.3	3093.4	"
1935-36							1079.8	912.3	866.6	826.0	984.2	2336.0	3397.0	"
1936-37							3579.6	3579.6	3579.6	3510.0	3579.6	3579.6	3579.6	"
1937-38							0.0	0.0	0.0	0.0	0.0	1048.2	2928.4	"
1938-39							2166.1	1907.2	1821.8	1777.3	2057.6	3117.5	3579.6	"
1939-40							1735.2	1629.0	1678.2	1758.0	2026.4	3060.0	"	"
1940-41							3242.9	2984.4	2925.5	3003.6	3431.7	3579.6	"	"
1941-42							2361.1	2107.3	2056.6	2005.3	2261.2	3289.0	3503.0	"
1942-43							1127.9	806.1	729.7	663.4	1013.0	2297.1	3463.4	"
1943-44							3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	"
1944-45							"	3440.9	3361.6	3312.9	3426.5	"	"	"
1945-46							0.0	0.0	0.0	0.0	0.0	377.9	2788.1	"
1946-47							"	"	"	"	"	1056.0	2944.4	"
1947-48							"	"	"	"	"	493.7	2814.6	"
1948-49							1496.4	1207.0	1152.5	1112.1	1371.6	2124.0	3416.8	"
1949-50							0.0	0.0	0.0	0.0	0.0	496.2	2460.3	"
1950-51							"	"	"	"	"	772.1	2958.4	"
1951-52							"	"	"	"	"	820.1	2929.8	"
1952-53							452.5	174.6	132.8	93.1	294.3	1391.6	2976.0	"
1953-54							0.0	0.0	0.0	0.0	0.0	117.9	2708.4	"
1954-55							488.9	418.0	457.5	424.9	627.8	2097.0	2709.0	"
1955-56							0.0	0.0	0.0	0.0	0.0	489.8	2818.2	"
1956-57							"	"	"	"	"	345.9	2949.6	"
1957-58							"	"	"	"	"	553.4	2895.7	"
DISTRIBUTION FACTORS							0.9710	0.9747	0.9691	0.9741	0.9530	0.7483	0.4631	N/A
FORECAST ERRORS (KSFD)							1485.5	1095.5	954.5	809.9	809.9	723.4	679.5	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	60550	89140
VARIABLE REFILL CURVES					80	MAF	5000	5000	5000	5000	5000	5000	66200	69200
(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	46300
OPERATING RULE CURVE LOWER LIMITS (KSFD)							157.9	27.6	0.0	0.0				

TABLE 6
(English Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES
DISTRIBUTION FACTORS AND FORECAST ERRORS
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2012 - 13 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (KSFD)														
	36.9	97.3	163.6	194.2	211.8	222.9	233.1	242.3	256.4	267.3	282.8	434.0	555.0	705.8
VARIABLE REFILL CURVES (KSFD)														
1928-29							368.7	351.1	360.0	356.8	373.4	435.4	578.8	705.8
1929-30							367.1	349.1	357.7	354.2	378.4	455.9	590.3	"
1930-31							311.6	294.9	307.1	308.6	331.3	405.4	578.8	"
1931-32							0.0	0.0	0.0	0.0	0.0	161.5	466.5	"
1932-33							"	"	"	"	"	0.0	331.4	"
1933-34							"	"	"	"	38.2	241.0	536.7	"
1934-35							22.9	12.7	36.4	36.7	60.9	212.9	468.5	"
1935-36							10.0	0.0	6.4	5.2	32.8	215.9	526.0	"
1936-37							304.5	286.0	296.8	293.6	314.6	390.4	560.5	"
1937-38							0.0	0.0	4.1	11.1	41.3	210.7	494.4	"
1938-39							134.0	122.7	136.2	138.2	170.0	302.6	560.9	"
1939-40							122.1	115.6	136.8	148.4	182.8	306.2	547.6	"
1940-41							220.6	211.4	228.4	241.8	287.3	394.7	573.4	"
1941-42							136.8	130.0	146.9	149.2	178.5	312.0	537.2	"
1942-43							125.7	111.7	127.2	127.9	166.7	319.0	522.5	"
1943-44							374.9	361.9	375.3	374.1	397.7	462.6	609.1	"
1944-45							272.9	260.1	274.7	274.0	292.2	376.5	563.0	"
1945-46							0.0	0.0	0.0	0.0	0.0	102.0	463.8	"
1946-47							"	"	"	"	"	147.0	473.8	"
1947-48							"	"	"	"	"	164.0	487.8	"
1948-49							186.3	169.4	181.5	179.2	204.5	337.7	588.9	"
1949-50							0.0	0.0	0.0	0.0	8.0	167.8	424.7	"
1950-51							"	"	"	"	0.0	132.0	456.1	"
1951-52							16.2	1.6	19.8	18.7	44.6	225.4	505.7	"
1952-53							13.9	2.1	18.3	"	41.7	200.3	469.7	"
1953-54							0.0	0.0	0.0	0.0	0.0	61.3	400.3	"
1954-55							"	"	"	"	"	146.8	402.6	"
1955-56							"	"	"	"	"	112.4	456.9	"
1956-57							"	"	"	"	"	162.6	523.5	"
1957-58							"	"	"	"	"	102.3	476.9	"
DISTRIBUTION FACTORS							0.9720	0.9790	0.9740	0.9790	0.9570	0.7580	0.4690	N/A
FORECAST ERRORS (KSFD)							127.7	104.3	105.0	93.8	93.8	86.9	78.0	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	100	100	100	100	100	100	100	100	100	100	100	293	3997	2456
VARIABLE REFILL CURVES					80	MAF	100	100	100	100	100	1400	1800	1800
(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
OPERATING RULE CURVE LOWER LIMITS (KSFD)							78.2	19.0	0.0	0.0				

TABLE 7
(English Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2012 - 13 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	3203.0	3086.0	2958.9	2958.9	2958.9	3068.3	3529.2	3529.2
1929-30	"	"	"	"	"	"	3147.0	2979.3	2791.2	2791.2	2791.2	2823.2	3248.4	"
1930-31	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3331.6	3529.2	"
1931-32	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	2299.1	3387.3	"
1932-33	"	"	"	"	"	"	"	"	"	"	"	1661.4	2868.9	"
1933-34	"	"	"	"	"	"	"	"	"	"	1838.3	2743.4	3216.5	"
1934-35	"	"	"	"	"	"	"	"	"	"	1472.2	1918.6	2873.0	"
1935-36	"	"	"	"	"	"	"	"	"	"	1556.5	2718.7	3529.2	"
1936-37	"	"	"	"	"	"	3111.5	2908.1	2689.7	2689.7	2689.7	2800.6	3382.0	"
1937-38	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1513.3	2307.3	3253.6	"
1938-39	"	"	"	"	"	"	2836.9	2385.3	1894.2	1894.2	1961.6	3164.1	3305.7	"
1939-40	"	"	"	"	"	"	2994.5	2679.5	2339.7	2339.7	2339.7	3114.5	3335.3	"
1940-41	"	"	"	"	"	"	3320.1	3309.8	3299.6	3299.6	3299.6	3339.5	3396.4	"
1941-42	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	1955.6	3280.3	"
1942-43	"	"	"	"	"	"	"	"	"	"	"	1754.0	2831.9	"
1943-44	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3410.6	3529.2	"
1944-45	"	"	"	"	"	"	2826.7	2375.2	1874.0	1874.0	1874.0	2395.8	,,	"
1945-46	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	2710.5	3296.8	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	2535.7	3529.2	"
1947-48	"	"	"	"	"	"	"	"	"	"	"	2327.9	"	"
1948-49	"	"	"	"	"	"	"	"	"	"	1498.9	2430.8	3525.1	"
1949-50	"	"	"	"	"	"	"	"	"	"	1472.2	1472.2	2727.0	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	2469.8	3119.9	"
1951-52	"	"	"	"	"	"	"	"	"	"	1546.2	2498.6	3249.4	"
1952-53	"	"	"	"	"	"	"	"	"	"	1472.2	1953.5	3109.6	"
1953-54	"	"	"	"	"	"	"	"	"	"	,,	1863.0	2342.3	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	1472.2	2926.5	3516.9
1955-56	"	"	"	"	"	"	"	"	"	"	"	2284.7	3282.4	3529.2
1956-57	"	"	"	"	"	"	"	"	"	"	"	3000.5	3529.2	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	2574.7	"	"

TABLE 8
(English Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2012 - 13 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	3188.4	3156.6	3121.4	3121.4	3121.4	3220.9	3579.6	3579.6
1929-30	"	"	"	"	"	"	3134.4	3053.8	2964.6	2964.6	2964.6	2964.6	"	"
1930-31	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3579.6	"	"
1931-32	"	"	"	"	"	"	2726.5	2261.7	1764.6	1764.6	1764.6	2359.9	"	"
1932-33	"	"	"	"	"	"	2721.0	2267.2	"	"	"	1764.6	3211.2	"
1933-34	"	"	"	"	"	"	"	"	"	"	2151.2	2445.2	3579.6	"
1934-35	"	"	"	"	"	"	"	"	"	"	1764.6	2036.8	,,	"
1935-36	"	"	"	"	"	"	2726.5	2261.7	"	"	2180.2	2889.9	"	"
1936-37	"	"	"	"	"	"	3100.7	2989.8	2866.8	2866.8	2866.8	2879.8	"	"
1937-38	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	2073.1	"	"
1938-39	"	"	"	"	"	"	2846.0	2504.8	2127.1	2127.1	2127.1	2267.4	"	"
1939-40	"	"	"	"	"	"	2988.4	2776.0	2540.8	2540.8	2540.8	3121.0	"	"
1940-41	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3331.7	"	"
1941-42	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	2004.2	2908.0	"
1942-43	"	"	"	"	"	"	"	"	"	"	2289.1	2612.2	3579.6	"
1943-44	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3297.0	"	"
1944-45	"	"	"	"	"	"	2840.2	2493.8	2110.3	2110.3	2110.3	2184.5	"	"
1945-46	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	1933.4	"	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	2231.0	"	"
1947-48	"	"	"	"	"	"	2726.5	2261.7	"	"	"	2080.4	"	"
1948-49	"	"	"	"	"	"	2721.0	2267.2	"	"	"	2991.5	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	1764.6	2621.3	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	2107.6	3579.6	"
1951-52	"	"	"	"	"	"	2726.5	2261.7	"	"	1949.7	2724.7	"	"
1952-53	"	"	"	"	"	"	2721.0	2267.2	"	"	1764.6	1764.6	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	2180.2	2675.7	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	1770.0	2741.1	"
1955-56	"	"	"	"	"	"	2726.5	2261.7	"	"	1918.9	2626.7	3579.6	"
1956-57	"	"	"	"	"	"	2721.0	2267.2	"	"	1764.6	2664.8	"	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	2697.5	"	"

TABLE 9
(English Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2012 - 13 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	432.4	705.8	705.8
1929-30	"	"	"	"	"	"	408.7	322.6	322.6	322.6	322.6	436.0	655.1	"
1930-31	"	"	"	"	"	"	390.7	288.3	288.3	288.3	292.9	434.2	656.2	"
1931-32	"	"	"	"	"	"	273.7	65.5	65.5	65.5	65.5	275.6	626.7	"
1932-33	"	"	"	"	"	"	"	"	"	"	"	133.0	492.4	689.5
1933-34	"	"	"	"	"	"	"	"	"	"	509.3	605.2	687.2	705.8
1934-35	"	"	"	"	"	"	"	"	"	"	65.5	167.7	485.6	"
1935-36	"	"	"	"	"	"	"	"	"	"	104.3	336.7	660.2	"
1936-37	"	"	"	"	"	"	374.8	258.1	258.1	258.1	258.1	377.7	621.4	"
1937-38	"	"	"	"	"	"	290.1	96.8	96.8	96.8	117.0	293.8	631.4	"
1938-39	"	"	"	"	"	"	285.1	87.2	87.2	87.2	112.1	337.8	558.5	"
1939-40	"	"	"	"	"	"	297.8	111.4	111.4	111.4	111.4	305.6	582.5	"
1940-41	"	"	"	"	"	"	344.4	200.1	200.1	200.1	216.2	371.9	619.9	"
1941-42	"	"	"	"	"	"	326.1	165.3	165.3	165.3	165.3	316.8	541.0	"
1942-43	"	"	"	"	"	"	329.3	171.4	171.4	171.4	171.4	242.1	444.0	"
1943-44	"	"	"	"	"	"	411.1	327.2	327.2	327.2	327.2	440.4	672.2	"
1944-45	"	"	"	"	"	"	381.5	270.7	270.7	270.7	270.7	393.7	653.5	"
1945-46	"	"	"	"	"	"	273.7	65.5	65.5	65.5	73.2	327.0	677.9	"
1946-47	"	"	"	"	"	"	"	"	"	"	83.1	313.8	637.8	"
1947-48	"	"	"	"	"	"	"	"	"	"	65.5	250.0	658.3	"
1948-49	"	"	"	"	"	"	368.0	245.0	245.0	245.0	264.6	485.8	705.8	"
1949-50	"	"	"	"	"	"	273.7	65.5	65.5	65.5	65.5	181.5	533.9	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	527.9	606.7	"
1951-52	"	"	"	"	"	"	"	"	"	"	95.4	295.2	595.3	"
1952-53	"	"	"	"	"	"	"	"	"	"	65.5	188.5	489.6	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	189.7	435.9	688.8
1954-55	"	"	"	"	"	"	"	"	"	"	"	72.3	"	694.6
1955-56	"	"	"	"	"	"	"	"	"	"	"	321.2	636.6	705.8
1956-57	"	"	"	"	"	"	"	"	"	"	71.7	376.5	691.9	"
1957-58	"	"	"	"	"	"	"	"	"	"	65.5	334.7	683.1	"

TABLE 10
(English Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN TREATY STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2012 - 13 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3416.4	3296.3	3381.6	3498.2	3745.7	5881.5	7449.1	7814.6
1929-30	"	"	"	"	"	"	"	"	3344.7	3445.9	"	5751.1	7203.8	"
1930-31	"	"	"	"	"	"	3371.0	"	3381.6	3498.2	"	5854.5	7259.0	"
1931-32	"	"	"	"	"	"	1187.4	797.3	682.8	671.5	788.8	2225.3	6017.9	"
1932-33	"	"	"	"	"	"	1094.0	739.2	642.1	628.6	706.3	1913.5	5609.2	7798.3
1933-34	"	"	"	"	"	"	515.9	75.1	0.0	0.0	39.0	2331.1	6551.1	7814.6
1934-35	"	"	"	"	"	"	2243.6	1929.7	2018.1	2041.1	2310.6	3998.2	6358.2	"
1935-36	"	"	"	"	"	"	2242.9	1832.7	1724.8	1669.2	1950.0	4355.5	6997.7	"
1936-37	"	"	"	"	"	"	3363.9	3294.9	3381.6	3489.0	3721.0	5610.0	7516.6	"
1937-38	"	"	"	"	"	"	1466.3	1092.9	982.6	982.8	1106.0	3060.4	6362.2	"
1938-39	"	"	"	"	"	"	3193.4	3124.0	3212.4	3318.1	3575.0	4922.5	7440.3	"
1939-40	"	"	"	"	"	"	3147.9	2984.8	3023.2	3111.6	3409.9	5565.6	7237.6	"
1940-41	"	"	"	"	"	"	3280.0	3236.9	3325.3	3431.0	3679.1	5821.0	7501.3	"
1941-42	"	"	"	"	"	"	3196.2	3166.8	3257.1	3340.1	3402.1	4271.8	6573.3	"
1942-43	"	"	"	"	"	"	2780.4	2398.2	2329.1	2263.5	2651.9	4293.2	6739.3	"
1943-44	"	"	"	"	"	"	3416.4	3296.3	3381.6	3498.2	3745.7	5883.1	7620.6	"
1944-45	"	"	"	"	"	"	3332.3	"	"	"	3733.6	4913.5	7533.3	"
1945-46	"	"	"	"	"	"	887.7	484.0	367.8	344.0	435.6	1755.4	6095.4	"
1946-47	"	"	"	"	"	"	1001.4	651.4	564.0	562.0	678.8	2739.2	6329.9	"
1947-48	"	"	"	"	"	"	950.3	579.7	477.2	449.0	529.3	1989.4	6100.8	"
1948-49	"	"	"	"	"	"	3209.5	2856.8	2806.2	2763.5	3075.0	4814.2	7457.8	"
1949-50	"	"	"	"	"	"	1305.8	895.7	769.6	746.2	839.0	2136.2	5494.7	"
1950-51	"	"	"	"	"	"	1297.0	934.6	840.5	834.9	948.7	2576.1	6385.7	"
1951-52	"	"	"	"	"	"	1703.8	1298.8	1199.0	1168.8	1276.5	3012.9	6554.0	"
1952-53	"	"	"	"	"	"	2057.5	1674.0	1623.3	1583.4	1808.2	3533.6	6531.2	"
1953-54	"	"	"	"	"	"	860.8	485.9	400.5	390.2	474.1	1427.1	5418.3	7797.6
1954-55	"	"	"	"	"	"	1951.6	1652.0	1625.5	1589.3	1878.7	3314.5	5887.9	7791.1
1955-56	"	"	"	"	"	"	1169.0	792.4	678.1	657.2	746.0	2172.2	6160.9	7814.6
1956-57	"	"	"	"	"	"	1337.6	953.7	854.0	845.4	934.8	2164.6	6689.4	"
1957-58	"	"	"	"	"	"	1171.3	800.4	707.1	703.9	809.3	2208.6	6351.5	"

TABLE 11
(English Units)
COMPOSITE END STORAGE
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2012 - 13 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3416.4	1975.3	1269.1	1084.4	1064.0	2404.2	5861.9	7329.8
1929-30	7610.9	7692.2	6922.7	6011.6	4515.0	3294.3	1203.4	377.4	0.0	71.1	702.0	2186.1	4047.3	6172.6
1930-31	6700.3	6998.0	6563.2	5721.7	4489.7	2817.4	1169.1	212.3	0.0	0.2	1.4	1199.3	2916.8	3963.0
1931-32	3954.5	3820.7	2923.4	2307.6	1431.4	226.1	2.1	0.0	0.0	102.0	357.7	2225.3	5801.9	7640.5
1932-33	7797.1	7814.4	6977.4	6300.4	6075.2	5204.0	3097.6	1452.0	642.1	577.4	706.3	1918.5	5609.2	7674.3
1933-34	7814.6	7814.4	7544.2	7127.1	6394.7	5251.1	3240.4	1623.3	466.9	312.1	887.5	2582.1	4548.2	6115.6
1934-35	6484.1	6707.2	6017.4	5355.0	5415.6	4460.8	2365.0	1936.1	1109.8	861.5	994.8	2593.3	5787.1	7752.6
1935-36	7814.6	7796.7	7416.1	6675.0	5461.1	3978.1	2349.6	1690.8	1272.1	1153.5	1439.5	4355.5	6985.1	7814.6
1936-37	7814.6	7761.2	7157.3	6298.6	4805.4	3310.0	1313.8	498.5	60.7	30.4	31.6	1367.7	3519.7	5262.0
1937-38	5382.3	5428.2	4712.0	4150.5	3778.9	3013.7	1527.6	1045.1	638.2	535.7	670.3	2566.7	5775.0	7629.8
1938-39	7580.6	7589.7	7129.3	6548.3	5576.2	4587.5	3254.6	2758.1	1703.5	1726.4	1886.0	4164.1	5188.2	7288.1
1939-40	7585.0	7681.1	6965.8	6380.2	5388.6	4600.4	3221.2	2813.4	2004.9	2088.1	2428.6	4780.2	5589.4	6715.9
1940-41	6917.9	6985.1	6626.5	6408.7	5325.5	4098.2	2570.1	2194.2	1939.4	2150.6	1507.5	3195.1	3470.1	4565.0
1941-42	4596.3	4597.7	4279.1	4730.2	4329.1	4503.7	3247.8	2156.5	993.7	877.3	983.0	2720.2	5025.0	7444.0
1942-43	7649.6	7733.6	7105.1	6420.4	5757.3	5134.0	2911.4	2398.2	1320.3	1165.4	1407.2	2565.3	4962.2	7452.1
1943-44	7683.6	7814.4	7482.2	7052.8	6200.0	5157.7	3416.4	2161.5	1274.2	1174.8	1174.8	2399.3	3352.1	4118.8
1944-45	4386.1	4406.3	3605.2	3186.2	2397.2	1115.7	603.6	157.3	0.0	0.1	0.3	1673.2	4638.2	6049.2
1945-46	6045.1	5817.5	5098.5	4519.5	3926.7	3044.1	952.7	446.3	48.9	13.7	326.6	1755.4	5845.2	7690.6
1946-47	7814.6	7814.4	7544.2	7074.2	6394.7	5204.0	3013.4	1370.8	564.0	562.0	678.8	2739.2	6319.6	7752.6
1947-48	7814.6	7794.8	7544.2	7127.1	6394.7	5204.0	3062.7	1334.8	477.2	370.6	529.3	1989.4	6100.8	7685.0
1948-49	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3228.9	2826.4	1652.1	1425.4	1536.5	4084.5	6178.1	7139.9
1949-50	7479.1	7553.6	6932.7	6321.3	5966.3	5204.0	3011.8	1341.9	769.6	706.2	811.8	2086.8	5003.3	7814.6
1950-51	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3161.9	1516.7	906.0	900.4	1014.2	2576.1	5576.9	7690.6
1951-52	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3012.9	1309.1	880.2	813.1	1193.0	3012.9	6203.2	7752.6
1952-53	7814.6	7785.7	7302.6	6573.4	5393.0	4163.6	2167.2	1644.3	1206.4	951.4	998.3	2455.8	5726.2	7554.4
1953-54	7649.6	7814.4	7544.2	7127.1	6394.7	5204.0	3072.2	1516.0	400.5	319.7	382.2	1427.1	4935.7	7673.6
1954-55	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3120.1	1667.3	1242.8	1206.5	885.3	1941.1	5052.4	7679.4
1955-56	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3133.7	1380.0	678.3	645.3	746.2	2172.2	6144.3	7752.6
1956-57	7807.9	7814.4	7544.2	7127.1	6394.7	5204.0	3033.1	1384.3	854.0	819.4	934.8	2210.5	5765.8	7118.1
1957-58	7329.9	7421.3	6828.7	6389.2	5440.1	4649.1	2509.1	915.1	595.8	643.4	809.3	2208.6	6348.2	7621.2
Max	7814.6	7814.4	7544.2	7127.1	6394.7	5251.1	3416.4	2826.4	2004.9	2150.6	2428.6	4780.2	6985.1	7814.6
Median	7666.6	7773.5	7143.3	6484.4	5666.8	4891.6	3013.2	1484.0	811.8	759.7	886.4	2401.8	5599.3	7587.8
Average	7147.2	7178.1	6701.0	6189.9	5400.5	4328.5	2513.0	1470.1	832.4	776.3	903.0	2518.5	5275.9	6997.1
Min	3954.5	3820.7	2923.4	2307.6	1431.4	226.1	2.1	0.0	0.0	0.1	0.3	1199.3	2916.8	3963.0

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	2011-12 2012-13 /3
MICA TARGET OPERATION						
(ksfd[xxxx.x] or cfs [xxxxx])						
AUG 15	3499.2	3499.1	3454.2	3454.2	3439.2	3364.2
AUG 31	FULL	FULL	FULL	FULL	FULL	FULL
SEP	FULL	3524.1	FULL	FULL	FULL	FULL
OCT	3374.1	3344.1	3428.4	3428.4	3428.4	3428.4
NOV	20000	23000	20000	22000	21000	21000
DEC	23000	25000	25000	25000	25000	25000
JAN	25000	26000	24000	23000	27000	24000
FEB	21000	22000	21000	20000	21000	21000
MAR	19000	20000	18000	17000	21000	17000
APR 15	204.1	16000	18000	18000	22000	20000
APR 30	15000	13000	12000	11000	10000	10000
MAY	10000	10000	10000	10000	8000	8000
JUN	10000	10000	10000	10000	8000	8000
JUL	3449.2	3449.1	3379.2	3436.2	3467.2	3467.2
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (ksfd)						
1928 AUG 31	7808.9	7678.3	7786.1	7811.6	7794.1	7814.4
1928 DEC	5213.8	4938.9	5133.8	5110.5	5086.0	5204.0
1929 APR15	1598.5	927.1	839.3	671.5	1048.2	1084.4
1929 JUL	7280.7	7222	7147.7	7168.9	7233.2	7329.8
COMPOSITE CANADIAN TREATY STORAGE CONTENT (ksfd)						
60-Yr Average						
AUG 31	7415.0	7238.3	7360.7	7455.5	7438.0	7362.8
DEC	4759.5	4437.3	4634.9	4640.3	4612.9	4630.0
APR15	1097.7	1085.8	1178.5	877.8	842.6	908.6
JUL	7262.0	7215.5	7193.7	7277.6	7268.9	7147.1
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)						
U.S. Firm Energy	-1.2	-0.1	-0.2	-0.3	-0.3	0.1
U.S. Dependable Peaking Capacity	16.0	-51.0	-21.0	-2.7	-19.1	-22.9
U.S. Average Annual Usable Secondary Energy	12.9	10.5	0.3	13.8	16.0	21.6
BCH Firm Energy	43.1	97.7	90.3	50.2	34.4	43.6
BCH Dependable Peaking Capacity	8.0	2.0	11.0	44.9	43.8	41.7
BCH Average Annual Usable Secondary Energy	-24.3	-55.7	-29.3	-28.2	-20.8	-13.9
COORDINATED HYDRO MODEL LOAD (MW)						
AUG 15	10439	11097	11137	11138	11138	10969
AUG 31	10435	11125	11165	11166	11167	11104
SEP	10101	10809	10849	10850	11025	11081
OCT	10186	9742	9782	9783	9958	9920
NOV	11807	10817	11157	11157	11333	11458
DEC	13377	12853	13192	13193	13369	13316
JAN	13122	12735	13075	13076	13076	12878
FEB	12240	11561	11901	11901	11902	11721
MAR	11175	11275	11315	11316	10967	10501
APR 15	10541	10550	10589	10590	10241	9786
APR 30	13065	14061	12822	12823	12475	11502
MAY	13752	14729	13491	13491	13493	13287
JUN	13114	14039	14079	14079	14080	13867
JUL	12079	12383	12723	12724	12725	12531
ANNUAL AVERAGE	11933	12034	12037	12038	12039	11855

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.
3/ The AOP/DDPB 2012-13 utilize the same system regulation studies as the 2011-12 AOP/DDPB.

TABLE 1M
(Metric Units)
MICA PROJECT OPERATING CRITERIA
2012-13 ASSURED OPERATING PLAN

		Target Operation		Target Operation Limits		
Month	End of Previous Month **Arrow** Storage Content (hm3)	Month Average Outflow (m^3/s)	End-of-Month Treaty Storage Content 1/ (hm3)	Minimum Treaty Storage Content 2/ (hm^3)	Maximum Outflow 1/ (m^3/s)	Minimum Outflow (m^3/s)
August 1-15	8,073.7 - FULL	-	8,230.8	-	962.77	424.75
	5,309.1 - 8,073.7	707.92	-	0.0	-	424.75
	3,669.9 - 5,309.1	566.34	-	0.0	-	424.75
	0.0 - 3,669.9	906.14	-	0.0	0.00	424.75
August 16-31	6,630.2 - FULL	-	8,634.5	-	962.77	424.75
	4,770.8 - 6,630.2	707.92	-	0.0	-	424.75
	0.0 - 4,770.8	906.14	-	0.0	-	424.75
September	8,636.4 - FULL	-	8,634.5	-	962.77	283.17
	8,318.4 - 8,636.4	679.60	-	0.0	-	283.17
	6,850.4 - 8,318.4	764.55	-	0.0	-	283.17
	0.0 - 6,850.4	906.14	-	0.0	-	283.17
October	8,416.2 - FULL	-	8,387.8	-	962.77	283.17
	6,361.1 - 8,416.2	538.02	-	0.0	-	283.17
	4,893.2 - 6,361.1	622.97	-	0.0	-	283.17
	0.0 - 4,893.2	906.14	-	0.0	-	283.17
November	8,171.6 - FULL	594.65	-	0.0	-	283.17
	7,657.8 - 8,171.6	538.02	-	0.0	-	283.17
	1,027.6 - 7,657.8	707.92	-	0.0	-	283.17
	0.0 - 1,027.6	906.14	-	0.0	-	283.17
December	6,703.6 - FULL	707.92	-	499.3	-	283.17
	4,403.8 - 6,703.6	622.97	-	499.3	-	283.17
	734.0 - 4,403.8	764.55	-	499.3	-	283.17
	0.0 - 734.0	906.14	-	499.3	-	283.17
January	6,459.0 - FULL	679.60	-	499.3	-	339.80
	5,333.5 - 6,459.0	764.55	-	499.3	-	339.80
	3,302.9 - 5,333.5	707.92	-	499.3	-	339.80
	0.0 - 3,302.9	821.19	-	499.3	-	339.80
February	3,351.8 - FULL	594.65	-	0.0	-	339.80
	2,201.9 - 3,351.8	736.24	-	0.0	-	339.80
	1,223.3 - 2,201.9	594.65	-	0.0	-	339.80
	0.0 - 1,223.3	736.24	-	0.0	-	339.80
March	1,957.3 - FULL	481.39	-	0.0	-	339.80
	1,883.9 - 1,957.3	736.24	-	0.0	-	339.80
	1,247.8 - 1,883.9	622.97	-	0.0	-	339.80
	0.0 - 1,247.8	707.92	-	0.0	-	339.80
April 1-15	2,177.5 - FULL	566.34	-	0.0	-	339.80
	856.3 - 2,177.5	283.17	-	0.0	-	339.80
	538.2 - 856.3	339.80	-	0.0	-	339.80
	0.0 - 538.2	622.97	-	0.0	-	339.80
April 16-30	1,394.5 - FULL	283.17	-	0.0	-	283.17
	269.1 - 1,394.5	424.75	-	0.0	-	283.17
	48.9 - 269.1	283.17	-	0.0	-	283.17
	0.0 - 48.9	424.75	-	0.0	-	283.17
May	1,565.8 - FULL	226.53	-	0.0	-	226.53
	1,272.2 - 1,565.8	339.80	-	0.0	-	226.53
	538.2 - 1,272.2	226.53	-	0.0	-	226.53
	0.0 - 538.2	283.17	0	0.0	-	226.53
June	3,939.0 - FULL	226.53	-	0.0	-	226.53
	2,495.5 - 3,939.0	283.17	-	0.0	-	226.53
	1,981.7 - 2,495.5	396.44	0	0.0	-	226.53
	0.0 - 1,981.7	509.70	-	0.0	-	226.53
July	7,780.1 - FULL	-	8,482.8	-	962.77	283.17
	6,532.4 - 7,780.1	-	8,331.1	-	962.77	283.17
	2,838.0 - 6,532.4	566.34	-	0.0	-	283.17
	0.0 - 2,838.0	877.82	-	0.0	-	283.17

1/ If the Mica target end-of-month storage content is less than 8634.5 hm^3, then a maximum outflow of 962.77 m^3/s will apply.
2/ Mica outflows will be reduced to minimum to maintain the reservoir above the minimum Treaty storage content. This will override any flow target.

TABLE 1.1aM
(Metric Units)
ARROW PROJECT OPERATING CRITERIA
DEFINITION
2012-13 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)
August 15 - December	-		URC	-	283.2
January	-		URC	1,982	283.2
February	1 Feb - 31 Jul	≤ 86	URC	1,699	566.3
		>86 to <99	URC to 4404		
		≥ 99	4404		
March	1 Mar - 31 Jul	≤ 80	URC	-	566.3
		>80 to <93	URC to 2202		
		≥ 93	2202		
April 15	1 Apr - 31 Jul	≤ 75	URC	-	424.8
		>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 5138		
		≥ 86	5138		
June	1 Jun - 31 Jul	≤ 41	URC	-	141.6
		>41 to <43	URC to 8318		
		≥ 43	8318		
July	-		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.

TABLE 1.1bM
(Metric Units)
ARROW PROJECT OPERATING CRITERIA
30 YEAR OPERATING DATA
FOR 2012-13 ASSURED OPERATING PLAN

	AUG15-DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
Maximum Average Monthly Flow Limits (m^3/s)									
	-	1,982	1,699	-	-	-	-	-	-
Minimum Average Monthly Flow Limits (m^3/s)									
	283.2	283.2	566.3	566.3	424.8	283.2	283.2	141.6	283.2
End-of-Period Maximum Storage Limits (hm^3)									
1928-29	-	-	URC	URC	URC	URC	URC	8563.7	-
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	5137.8	8318.4	-
1932-33	-	-	4403.8	2201.9	2201.9	2446.6	URC	URC	-
1933-34	-	-	4403.8	2201.9	2201.9	2446.6	URC	URC	-
1934-35	-	-	4403.8	2201.9	2201.9	2446.6	URC	8318.4	-
1935-36	-	-	4403.8	2201.9	2201.9	2446.6	URC	URC	-
1936-37	-	-	URC	URC	URC	URC	URC	8510.7	-
1937-38	-	-	4403.8	2201.9	2201.9	2446.6	URC	8318.4	-
1938-39	-	-	4719.0	2276.3	2845.9	3038.2	URC	URC	-
1939-40	-	-	4862.3	2942.7	4729.5	4820.2	URC	URC	-
1940-41	-	-	URC	URC	URC	URC	URC	URC	-
1941-42	-	-	4403.8	2201.9	2201.9	2446.6	URC	URC	-
1942-43	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-
1943-44	-	-	URC	URC	URC	URC	URC	URC	-
1944-45	-	-	4532.8	2365.6	2506.5	2726.0	URC	8318.4	-
1945-46	-	-	4403.8	2201.9	2201.9	2446.6	URC	8318.4	-
1946-47	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-
1947-48	-	-	4403.8	2201.9	2201.9	2446.6	URC	8318.4	-
1948-49	-	-	4403.8	2201.9	2201.9	2446.6	7203.2	URC	-
1949-50	-	-	4403.8	2201.9	2201.9	2446.6	URC	URC	-
1950-51	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-
1951-52	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-
1952-53	-	-	4403.8	2201.9	2201.9	2446.6	URC	8318.4	-
1953-54	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	URC	-
1954-55	-	-	4403.8	2201.9	2201.9	2446.6	URC	URC	-
1955-56	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-
1956-57	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-
1957-58	-	-	4403.8	2201.9	2201.9	2446.6	5137.8	8318.4	-

TABLE 3M
(Metric Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (hm3)
2012 - 13 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
							MICA							
1928-29	8634.5	8634.5	8618.3	8340.4	7346.8	5563.8	3735.4	1917.4	1235.8	632.9	424.5	1147.4	5173.8	7587.3
1929-30	8309.5	8573.3	8142.2	6045.2	4787.5	3501.0	1254.6	392.7	0.0	0.0	538.7	1525.9	2860.5	6053.8
1930-31	7004.3	7771.3	7785.0	5999.2	5107.7	3024.7	1826.4	164.9	0.0	0.0	0.0	654.2	2313.2	5122.9
1931-32	4904.2	4487.8	2831.4	2603.6	1498.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							ARROW							
1928-29	8757.8	8757.3	8129.5	7420.2	6779.0	6091.2	3749.6	2280.5	1466.0	1677.6	1808.5	4077.0	7837.8	8692.4
1929-30	8658.7	8650.8	7342.9	7217.6	4930.1	3574.2	1152.8	420.3	0.0	171.3	1095.1	3555.9	6270.3	7996.9
1930-31	8242.8	8070.0	6850.7	6680.1	4530.8	3052.1	683.3	354.5	0.0	0.0	3.4	1895.4	4454.0	4232.3
1931-32	4351.2	4623.3	4113.9	2763.9	1834.2	553.2	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							DUNCAN							
1928-29	1726.8	1726.8	1709.7	1676.4	1519.3	1077.0	873.4	634.9	403.2	342.5	370.2	657.6	1330.0	1653.2
1929-30	1652.4	1595.4	1451.8	1444.9	1328.7	984.5	536.8	110.3	0.0	2.7	83.7	266.7	771.2	1051.0
1930-31	1145.7	1279.8	1421.7	1319.2	1345.9	816.2	350.6	0.0	0.0	0.5	0.0	384.6	368.9	340.6
1931-32	419.3	236.3	207.0	278.2	169.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
							COMPOSITE							
1928-29	19119.0	19118.5	18457.5	17437.0	15645.1	12732.0	8358.5	4832.7	3104.9	2653.1	2603.2	5882.1	14341.6	17932.9
1929-30	18620.6	18819.5	16936.9	14707.8	11046.3	8059.8	2944.2	923.3	0.0	174.0	1717.5	5348.5	9902.0	15101.7
1930-31	16392.8	17121.1	16057.4	13998.6	10984.4	6893.0	2860.3	519.4	0.0	0.5	3.4	2934.2	7136.2	9695.8
1931-32	9674.7	9347.4	7152.3	5645.7	3502.0	553.2	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Note: These rule curves are input to the AOP 2013 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, AND OPERATING RULE CURVE LOWER LIMITS
2012 - 13 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	125.8	1551.9	3025.7	3462.6	3622.4	3662.8	3650.0	3621.9	3638.5	3699.7	3854.3	5755.6	8528.8	8634.5
VARIABLE REFILL CURVES (hm^3)														
1928-29							6751.1	6316.6	6169.0	6148.5	6248.6	7475.3	8203.4	8634.5
1929-30							4249.9	3719.5	3548.3	3571.8	3954.6	5992.2	7509.0	"
1930-31							4880.7	4372.3	4190.0	4160.4	4381.3	6038.6	7691.8	"
1931-32							2327.4	1836.6	1670.5	1642.9	1929.9	3859.0	6966.9	"
1932-33							2098.9	1694.5	1570.9	1537.9	1728.0	3611.6	6569.1	"
1933-34							99.1	0.0	0.0	0.0	2.0	2990.2	7184.4	"
1934-35							3031.1	2580.9	2487.2	2503.3	2674.8	4388.4	6841.4	"
1935-36							2654.3	2205.3	2084.0	2050.2	2282.7	4412.6	7522.5	"
1936-37							6718.5	6233.9	6049.9	6002.7	6220.4	7504.9	8280.4	"
1937-38							3009.8	2559.9	2394.0	2377.3	2604.9	4407.5	7191.5	"
1938-39							4171.4	3830.1	3681.9	3715.4	3987.4	5863.5	8191.1	"
1939-40							3653.2	3222.1	3116.4	3135.3	3452.1	5382.5	7609.8	"
1940-41							5333.5	4875.3	4740.7	4758.6	5191.6	6964.2	8236.9	"
1941-42							4280.5	3831.8	3677.2	3638.3	3824.5	5436.5	7653.1	"
1942-43							4568.2	4063.8	3901.8	3862.4	4235.3	5942.7	7774.0	"
1943-44							6977.1	6453.8	6303.1	6278.2	6446.0	7773.3	8622.2	"
1944-45							6430.6	5997.8	5881.1	5882.1	6003.4	7224.2	8315.2	"
1945-46							1594.2	1070.1	899.9	841.6	1065.7	3120.6	6956.8	"
1946-47							1872.4	1479.7	1379.9	1375.0	1660.7	3758.4	7123.7	"
1947-48							1747.3	1304.3	1167.5	1098.5	1295.0	3258.1	6846.5	"
1948-49							5898.2	5392.7	5189.9	5149.8	5339.4	6624.3	8634.5	"
1949-50							2617.1	2077.4	1882.9	1825.6	2033.1	3799.3	6384.8	"
1950-51							2595.6	2172.6	2056.3	2042.6	2321.1	4090.7	7269.3	"
1951-52							3590.8	3063.6	2885.0	2813.8	3013.9	4813.4	7629.6	"
1952-53							4279.1	3795.4	3640.0	3600.4	3746.4	5193.1	7548.9	"
1953-54							1528.4	1074.8	979.9	954.7	1159.9	3053.1	6316.6	"
1954-55							3387.3	2972.6	2857.6	2848.8	3060.4	4632.8	6792.4	"
1955-56							2282.4	1824.7	1659.0	1607.9	1825.1	3841.1	7060.3	"
1956-57							2694.9	2219.3	2089.4	2068.3	2287.1	4051.8	7868.9	"
1957-58							2288.0	1844.2	1730.0	1722.1	1980.0	3799.3	7288.1	"
DISTRIBUTION FACTORS							0.9750	0.9770	0.9740	0.9812	0.9650	0.7950	0.4950	N/A
FORECAST ERRORS (hm^3)							1781.4	1276.9	1113.9	1028.3	1028.3	982.3	971.5	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	632.9	1560.3
VARIABLE REFILL CURVES					98.68	km^3	84.95	84.95	84.95	84.95	84.95	84.95	906.14	1076.04
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	84.95	84.95	84.95	84.95	84.95	84.95	509.70	914.63
					135.69	km^3	84.95	84.95	84.95	84.95	84.95	84.95	509.70	914.63
OPERATING RULE CURVE LOWER LIMITS (hm^3)							684.6	69.7	0.0	0.0				

TABLE 5M
(Metric Units)
ARROW
ASSURED AND VARIABLE REFILL CURVES,
DISTRIBUTION FACTORS AND FORECAST ERRORS,
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2012 - 13 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	0.0	0.0	0.0	0.0	0.0	1704.0	3642.5	3807.9	4007.5	4204.9	4617.9	7576.1	8757.8	8757.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							8757.8	8512.1	8225.4	8036.5	8324.7	8757.8	8663.6	8757.8
1929-30							5153.0	4468.9	4478.5	4471.6	5208.3	8180.9	8757.8	"
1930-31							6384.1	5630.3	5393.7	5285.3	5781.5	7823.4	8710.1	"
1931-32							0.0	0.0	0.0	0.0	0.0	1190.3	6615.1	"
1932-33							"	"	"	"	"	1069.9	6343.5	"
1933-34							"	"	"	"	"	2123.4	7530.3	"
1934-35							2266.8	2093.8	2361.2	2400.6	2829.2	5512.9	7568.2	"
1935-36							2641.8	2232.0	2120.2	2020.9	2407.9	5715.2	8311.0	"
1936-37							8757.8	8757.8	8757.8	8587.5	8757.8	8757.8	8757.8	"
1937-38							0.0	0.0	0.0	0.0	0.0	2564.5	7164.6	"
1938-39							5299.5	4666.1	4457.2	4348.3	5034.1	7627.2	8757.8	"
1939-40							4245.3	3985.5	4105.8	4301.1	4957.7	7486.5	"	"
1940-41							7934.0	7301.6	7157.5	7348.5	8395.9	8757.8	"	"
1941-42							5776.6	5155.7	5031.6	4906.1	5532.2	8046.8	8570.4	"
1942-43							2759.5	1972.2	1785.3	1623.1	2478.4	5620.0	8473.5	"
1943-44							8757.8	8757.8	8757.8	8757.8	8757.8	8757.8	8757.8	"
1944-45							"	8418.4	8224.4	8105.3	8383.2	"	"	"
1945-46							0.0	0.0	0.0	0.0	0.0	924.6	6821.3	"
1946-47							"	"	"	"	"	2583.6	7203.7	"
1947-48							"	"	"	"	"	1207.9	6886.1	"
1948-49							3661.1	2953.0	2819.7	2720.8	3355.7	5196.5	8359.5	"
1949-50							0.0	0.0	0.0	0.0	0.0	1214.0	6019.3	"
1950-51							"	"	"	"	"	1889.0	7237.9	"
1951-52							"	"	"	"	"	2006.4	7168.0	"
1952-53							1107.1	427.2	324.9	227.8	720.0	3404.7	7281.0	"
1953-54							0.0	0.0	0.0	0.0	0.0	288.5	6626.3	"
1954-55							1196.1	1022.7	1119.3	1039.5	1536.0	5130.5	6627.8	"
1955-56							0.0	0.0	0.0	0.0	0.0	1198.3	6894.9	"
1956-57							"	"	"	"	"	846.3	7216.4	"
1957-58							"	"	"	"	"	1353.9	7084.5	"
DISTRIBUTION FACTORS							0.9710	0.9747	0.9691	0.9741	0.9530	0.7483	0.4631	N/A
FORECAST ERRORS (hm^3)							3634.4	2680.2	2335.3	1981.5	1981.5	1769.9	1662.4	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	1714.59	2524.16
VARIABLE REFILL CURVES					98.68	km^3	141.58	141.58	141.58	141.58	141.58	141.58	1874.58	1959.53
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	141.58	141.58	141.58	141.58	141.58	141.58	1217.62	1614.06
					135.69	km^3	141.58	141.58	141.58	141.58	141.58	141.58	141.58	1311.07
OPERATING RULE CURVE LOWER LIMITS (hm^3)							386.3	67.5	0.0	0.0				

TABLE 6M
(Metric Units)
DUNCAN
ASSURED AND VARIABLE REFILL CURVES,
DISTRIBUTION FACTORS AND FORECAST ERRORS,
POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2012 - 13 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm^3)														
	90.3	238.1	400.3	475.1	518.2	545.3	570.3	592.8	627.3	654.0	691.9	1061.8	1357.8	1726.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							902.1	859.0	880.8	872.9	913.6	1065.2	1416.1	1726.8
1929-30							898.1	854.1	875.1	866.6	925.8	1115.4	1444.2	"
1930-31							762.4	721.5	751.3	755.0	810.6	991.8	1416.1	"
1931-32							0.0	0.0	0.0	0.0	0.0	395.1	1141.3	"
1932-33							"	"	"	"	"	0.0	810.8	"
1933-34							"	"	"	"	93.5	589.6	1313.1	"
1934-35							56.0	31.1	89.1	89.8	149.0	520.9	1146.2	"
1935-36							24.5	0.0	15.7	12.7	80.2	528.2	1286.9	"
1936-37							745.0	699.7	726.1	718.3	769.7	955.1	1371.3	"
1937-38							0.0	0.0	10.0	27.2	101.0	515.5	1209.6	"
1938-39							327.8	300.2	333.2	338.1	415.9	740.3	1372.3	"
1939-40							298.7	282.8	334.7	363.1	447.2	749.1	1339.7	"
1940-41							539.7	517.2	558.8	591.6	702.9	965.7	1402.9	"
1941-42							334.7	318.1	359.4	365.0	436.7	763.3	1314.3	"
1942-43							307.5	273.3	311.2	312.9	407.8	780.5	1278.3	"
1943-44							917.2	885.4	918.2	915.3	973.0	1131.8	1490.2	"
1944-45							667.7	636.4	672.1	670.4	714.9	921.1	1377.4	"
1945-46							0.0	0.0	0.0	0.0	0.0	249.6	1134.7	"
1946-47							"	"	"	"	"	359.6	1159.2	"
1947-48							"	"	"	"	"	401.2	1193.4	"
1948-49							455.8	414.4	444.1	438.4	500.3	826.2	1440.8	"
1949-50							0.0	0.0	0.0	0.0	19.6	410.5	1039.1	"
1950-51							"	"	"	"	0.0	322.9	1115.9	"
1951-52							39.6	3.9	48.4	45.8	109.1	551.5	1237.2	"
1952-53							34.0	5.1	44.8	"	102.0	490.0	1149.2	"
1953-54							0.0	0.0	0.0	0.0	0.0	150.0	979.4	"
1954-55							"	"	"	"	"	359.2	985.0	"
1955-56							"	"	"	"	"	275.0	1117.8	"
1956-57							"	"	"	"	"	397.8	1280.8	"
1957-58							"	"	"	"	"	250.3	1166.8	"
DISTRIBUTION FACTORS							0.9720	0.9790	0.9740	0.9790	0.9570	0.7580	0.4690	N/A
FORECAST ERRORS (hm^3)							312.4	255.2	256.9	229.5	229.5	212.6	190.8	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	8.30	113.18	69.55
VARIABLE REFILL CURVES					98.68	km^3	2.83	2.83	2.83	2.83	2.83	39.64	50.97	50.97
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	2.83	2.83	2.83	2.83	2.83	2.83	16.99	31.15
					135.69	km^3	2.83	2.83	2.83	2.83	2.83	2.83	16.99	28.32
OPERATING RULE CURVE LOWER LIMITS (hm^3)							191.3	46.5	0.0	0.0				

TABLE 7M
(Metric Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm3)
2012 - 13 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8634.5	8634.5	8634.5	8387.8	8387.8	8151.0	7836.4	7550.1	7239.2	7239.2	7239.2	7506.8	8634.5	8634.5
1929-30	"	"	"	"	"	"	7699.4	7289.1	6828.9	6828.9	6828.9	6907.2	7947.5	"
1930-31	"	"	"	"	"	"	8151.0	8151.0	8151.0	8151.0	8151.0	8151.0	8634.5	"
1931-32	"	"	"	"	"	"	6584.5	5168.4	3601.8	3601.8	3601.8	5624.9	8287.3	"
1932-33	"	"	"	"	"	"	"	"	"	"	"	4064.7	7019.0	"
1933-34	"	"	"	"	"	"	"	"	"	"	4497.5	6711.9	7869.4	"
1934-35	"	"	"	"	"	"	"	"	"	"	3601.8	4694.0	7029.0	"
1935-36	"	"	"	"	"	"	"	"	"	"	3808.1	6651.5	8634.5	"
1936-37	"	"	"	"	"	"	7612.5	7114.9	6580.6	6580.6	6580.6	6851.9	8274.3	"
1937-38	"	"	"	"	"	"	6584.5	5168.4	3601.8	3601.8	3702.4	5645.0	7960.2	"
1938-39	"	"	"	"	"	"	6940.7	5835.8	4634.3	4634.3	4799.2	7741.2	8087.6	"
1939-40	"	"	"	"	"	"	7326.3	6555.6	5724.3	5724.3	5724.3	7619.9	8160.1	"
1940-41	"	"	"	"	"	"	8122.9	8097.7	8072.7	8072.7	8072.7	8170.3	8309.5	"
1941-42	"	"	"	"	"	"	6584.5	5168.4	3601.8	3601.8	3601.8	4784.5	8025.5	"
1942-43	"	"	"	"	"	"	"	"	"	"	"	4291.3	6928.5	"
1943-44	"	"	"	"	"	"	8151.0	8151.0	8151.0	8151.0	8151.0	8344.3	8634.5	"
1944-45	"	"	"	"	"	"	6915.7	5811.1	4584.9	4584.9	4584.9	5861.5	,,	"
1945-46	"	"	"	"	"	"	6584.5	5168.4	3601.8	3601.8	3601.8	6631.4	8065.9	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	6203.8	8634.5	"
1947-48	"	"	"	"	"	"	"	"	"	"	"	5695.4	"	"
1948-49	"	"	"	"	"	"	"	"	"	"	3667.2	5947.1	8624.4	"
1949-50	"	"	"	"	"	"	"	"	"	"	3601.8	3601.8	6671.8	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	6042.6	7633.1	"
1951-52	"	"	"	"	"	"	"	"	"	"	3782.9	6113.0	7949.9	"
1952-53	"	"	"	"	"	"	"	"	"	"	3601.8	4779.4	7607.9	"
1953-54	"	"	"	"	"	"	"	"	"	"	,,	4558.0	5730.6	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	3601.8	7159.9	8604.4
1955-56	"	"	"	"	"	"	"	"	"	"	"	5589.7	8030.6	8634.5
1956-57	"	"	"	"	"	"	"	"	"	"	"	7340.9	8634.5	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	6299.2	"	"

TABLE 8M
(Metric Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm3)
2012 - 13 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8757.8	8757.8	8757.8	8449.5	8449.5	7887.0	7800.7	7722.9	7636.7	7636.7	7636.7	7880.2	8757.8	8757.8
1929-30	"	"	"	"	"	"	7668.5	7471.4	7253.1	7253.1	7253.1	7253.1	"	"
1930-31	"	"	"	"	"	"	7887.0	7887.0	7887.0	7887.0	7887.0	8757.8	"	"
1931-32	"	"	"	"	"	"	6670.6	5533.4	4317.2	4317.2	4317.2	5773.7	"	"
1932-33	"	"	"	"	"	"	6657.1	5546.9	"	"	"	4317.2	7856.4	"
1933-34	"	"	"	"	"	"	"	"	"	"	5263.1	5982.4	8757.8	"
1934-35	"	"	"	"	"	"	"	"	"	"	4317.2	4983.2	,,	"
1935-36	"	"	"	"	"	"	6670.6	5533.4	"	"	5334.0	7070.4	"	"
1936-37	"	"	"	"	"	"	7586.1	7314.8	7013.8	7013.8	7013.8	7045.6	"	"
1937-38	"	"	"	"	"	"	6657.1	5546.9	4317.2	4317.2	4317.2	5072.0	"	"
1938-39	"	"	"	"	"	"	6963.0	6128.2	5204.1	5204.1	5204.1	5547.4	"	"
1939-40	"	"	"	"	"	"	7311.3	6791.7	6216.3	6216.3	6216.3	7635.8	"	"
1940-41	"	"	"	"	"	"	7887.0	7887.0	7887.0	7887.0	7887.0	8151.3	"	"
1941-42	"	"	"	"	"	"	6657.1	5546.9	4317.2	4317.2	4317.2	4903.4	7114.6	"
1942-43	"	"	"	"	"	"	"	"	"	"	5600.5	6390.9	8757.8	"
1943-44	"	"	"	"	"	"	7887.0	7887.0	7887.0	7887.0	7887.0	8066.4	"	"
1944-45	"	"	"	"	"	"	6948.8	6101.3	5163.0	5163.0	5163.0	5344.5	"	"
1945-46	"	"	"	"	"	"	6657.1	5546.9	4317.2	4317.2	4317.2	4730.2	"	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	5458.3	"	"
1947-48	"	"	"	"	"	"	6670.6	5533.4	"	"	"	5089.9	"	"
1948-49	"	"	"	"	"	"	6657.1	5546.9	"	"	"	7318.9	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	"	4317.2	6413.2	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	5156.4	8757.8	"
1951-52	"	"	"	"	"	"	6670.6	5533.4	"	"	4770.1	6666.2	"	"
1952-53	"	"	"	"	"	"	6657.1	5546.9	"	"	4317.2	4317.2	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	5334.0	6546.3	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	4330.4	6706.3	"
1955-56	"	"	"	"	"	"	6670.6	5533.4	"	"	4694.7	6426.4	8757.8	"
1956-57	"	"	"	"	"	"	6657.1	5546.9	"	"	4317.2	6519.6	"	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	6599.6	"	"

TABLE 9M
(Metric Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm3)
2012 - 13 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	1726.8	1726.8	1726.8	1726.8	1726.8	1233.3	1022.7	832.6	832.6	832.6	832.6	1057.9	1726.8	1726.8
1929-30	"	"	"	"	"	"	999.9	789.3	789.3	789.3	789.3	1066.7	1602.8	"
1930-31	"	"	"	"	"	"	955.9	705.3	705.3	705.3	716.6	1062.3	1605.4	"
1931-32	"	"	"	"	"	"	669.6	160.3	160.3	160.3	160.3	674.3	1533.3	"
1932-33	"	"	"	"	"	"	"	"	"	"	"	325.4	1204.7	1686.9
1933-34	"	"	"	"	"	"	"	"	"	"	1246.0	1480.7	1681.3	1726.8
1934-35	"	"	"	"	"	"	"	"	"	"	160.3	410.3	1188.1	"
1935-36	"	"	"	"	"	"	"	"	"	"	255.2	823.8	1615.2	"
1936-37	"	"	"	"	"	"	917.0	631.5	631.5	631.5	631.5	924.1	1520.3	"
1937-38	"	"	"	"	"	"	709.8	236.8	236.8	236.8	286.2	718.8	1544.8	"
1938-39	"	"	"	"	"	"	697.5	213.3	213.3	213.3	274.3	826.5	1366.4	"
1939-40	"	"	"	"	"	"	728.6	272.5	272.5	272.5	272.5	747.7	1425.1	"
1940-41	"	"	"	"	"	"	842.6	489.6	489.6	489.6	528.9	909.9	1516.6	"
1941-42	"	"	"	"	"	"	797.8	404.4	404.4	404.4	404.4	775.1	1323.6	"
1942-43	"	"	"	"	"	"	805.7	419.3	419.3	419.3	419.3	592.3	1086.3	"
1943-44	"	"	"	"	"	"	1005.8	800.5	800.5	800.5	800.5	1077.5	1644.6	"
1944-45	"	"	"	"	"	"	933.4	662.3	662.3	662.3	662.3	963.2	1598.8	"
1945-46	"	"	"	"	"	"	669.6	160.3	160.3	160.3	179.1	800.0	1658.5	"
1946-47	"	"	"	"	"	"	"	"	"	"	203.3	767.7	1560.4	"
1947-48	"	"	"	"	"	"	"	"	"	"	160.3	611.6	1610.6	"
1948-49	"	"	"	"	"	"	900.3	599.4	599.4	599.4	647.4	1188.5	1726.8	"
1949-50	"	"	"	"	"	"	669.6	160.3	160.3	160.3	160.3	444.1	1306.2	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	1291.5	1484.3	"
1951-52	"	"	"	"	"	"	"	"	"	"	233.4	722.2	1456.4	"
1952-53	"	"	"	"	"	"	"	"	"	"	160.3	461.2	1197.8	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	464.1	1066.5	1685.2
1954-55	"	"	"	"	"	"	"	"	"	"	"	176.9	"	1699.4
1955-56	"	"	"	"	"	"	"	"	"	"	"	785.8	1557.5	1726.8
1956-57	"	"	"	"	"	"	"	"	"	"	175.4	921.1	1692.8	"
1957-58	"	"	"	"	"	"	"	"	"	"	160.3	818.9	1671.3	"

TABLE 10M
(Metric Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN TREATY STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (hm3)
2012 - 13 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.0	19118.5	18457.5	17437.0	15645.1	12732.0	8358.5	8064.6	8273.3	8558.6	9164.1	14389.5	18224.8	19119.0
1929-30	"	"	"	"	"	"	"	"	8183.1	8430.7	"	14070.5	17624.6	"
1930-31	"	"	"	"	"	"	8247.4	"	8273.3	8558.6	"	14323.5	17759.7	"
1931-32	"	"	"	"	"	"	2905.1	1950.7	1670.5	1642.9	1929.9	5444.4	14723.2	"
1932-33	"	"	"	"	"	"	2676.6	1808.5	1570.9	1537.9	1728.0	4681.5	13723.3	19079.1
1933-34	"	"	"	"	"	"	1262.2	183.7	0.0	0.0	95.4	5703.2	16027.8	19119.0
1934-35	"	"	"	"	"	"	5489.1	4721.2	4937.4	4993.7	5653.1	9781.9	15555.8	"
1935-36	"	"	"	"	"	"	5487.4	4483.8	4219.9	4083.8	4770.8	10656.1	17120.4	"
1936-37	"	"	"	"	"	"	8230.0	8061.2	8273.3	8536.1	9103.7	13725.3	18389.9	"
1937-38	"	"	"	"	"	"	3587.4	2673.9	2404.0	2404.5	2705.9	7487.5	15565.6	"
1938-39	"	"	"	"	"	"	7812.9	7643.1	7859.4	8118.0	8746.5	12043.3	18203.3	"
1939-40	"	"	"	"	"	"	7701.6	7302.5	7396.5	7612.8	8342.6	13616.7	17707.3	"
1940-41	"	"	"	"	"	"	8024.8	7919.3	8135.6	8394.2	9001.2	14241.5	18352.5	"
1941-42	"	"	"	"	"	"	7819.7	7747.8	7968.7	8171.8	8323.5	10451.3	16082.1	"
1942-43	"	"	"	"	"	"	6802.5	5867.4	5698.3	5537.8	6488.1	10503.6	16488.2	"
1943-44	"	"	"	"	"	"	8358.5	8064.6	8273.3	8558.6	9164.1	14393.4	18644.4	"
1944-45	"	"	"	"	"	"	8152.7	"	"	"	9134.5	12021.2	18430.8	"
1945-46	"	"	"	"	"	"	2171.8	1184.1	899.9	841.6	1065.7	4294.7	14912.9	"
1946-47	"	"	"	"	"	"	2450.0	1593.7	1379.9	1375.0	1660.7	6701.7	15486.6	"
1947-48	"	"	"	"	"	"	2325.0	1418.3	1167.5	1098.5	1295.0	4867.2	14926.1	"
1948-49	"	"	"	"	"	"	7852.3	6989.4	6865.6	6761.1	7523.2	11778.3	18246.1	"
1949-50	"	"	"	"	"	"	3194.7	2191.4	1882.9	1825.6	2052.7	5226.4	13443.2	"
1950-51	"	"	"	"	"	"	3173.2	2286.6	2056.3	2042.6	2321.1	6302.6	15623.1	"
1951-52	"	"	"	"	"	"	4168.5	3177.6	2933.4	2859.6	3123.1	7371.3	16034.9	"
1952-53	"	"	"	"	"	"	5033.8	4095.6	3971.5	3873.9	4423.9	8645.2	15979.1	"
1953-54	"	"	"	"	"	"	2106.0	1188.8	979.9	954.7	1159.9	3491.5	13256.3	19077.4
1954-55	"	"	"	"	"	"	4774.7	4041.7	3976.9	3888.3	4596.4	8109.2	14405.2	19061.5
1955-56	"	"	"	"	"	"	2860.0	1938.7	1659.0	1607.9	1825.1	5314.5	15073.1	19119.0
1956-57	"	"	"	"	"	"	3272.5	2333.3	2089.4	2068.3	2287.1	5295.9	16366.1	"
1957-58	"	"	"	"	"	"	2865.7	1958.2	1730.0	1722.1	1980.0	5403.5	15539.4	"

TABLE 11M
(Metric Units)
COMPOSITE END STORAGE
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2012 - 13 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.2	19118.7	18457.6	17437.2	15645.3	12732.1	8358.6	4832.8	3105.0	2653.1	2603.2	5882.1	14341.7	17933.1
1929-30	18620.8	18819.7	16937.1	14708.0	11046.4	8059.8	2944.2	923.3	0.0	174.0	1717.5	5348.5	9902.1	15101.9
1930-31	16393.0	17121.3	16057.5	13998.7	10984.5	6893.1	2860.3	519.4	0.0	0.5	3.4	2934.2	7136.2	9695.9
1931-32	9675.1	9347.7	7152.4	5645.8	3502.1	553.2	5.1	0.0	0.0	249.6	875.1	5444.4	14194.9	18693.2
1932-33	19076.4	19118.7	17070.9	15414.6	14863.6	12732.1	7578.6	3552.5	1571.0	1412.7	1728.0	4693.8	13723.5	18775.9
1933-34	19119.2	19118.7	18457.6	17437.2	15645.3	12847.3	7928.0	3971.6	1142.3	763.6	2171.4	6317.4	11127.6	14962.4
1934-35	15864.0	16409.8	14722.2	13101.5	13249.8	10913.8	5786.2	4736.9	2715.2	2107.7	2433.9	6344.8	14158.7	18967.5
1935-36	19119.2	19075.4	18144.2	16331.1	13361.1	9732.8	5748.5	4136.7	3112.3	2822.2	3521.9	10656.2	17089.7	19119.2
1936-37	19119.2	18988.6	17511.1	15410.2	11756.9	8098.2	3214.3	1219.6	148.5	74.4	77.3	3346.2	8611.3	12874.0
1937-38	13168.3	13280.6	11528.4	10154.6	9245.5	7373.3	3737.4	2556.9	1561.4	1310.6	1640.0	6279.7	14129.1	18667.1
1938-39	18546.7	18569.0	17442.5	16021.1	13642.7	11223.8	7962.7	6748.0	4167.8	4223.8	4614.3	10187.9	12693.5	17831.1
1939-40	18557.5	18792.6	17042.5	15609.8	13183.7	11255.3	7881.0	6883.3	4905.2	5108.7	5941.8	11695.2	13675.0	16431.1
1940-41	16925.3	17089.7	16212.4	15679.5	13029.4	10026.7	6288.0	5368.3	4744.9	5261.7	3688.2	7817.1	8489.9	11168.7
1941-42	11245.3	11248.7	10469.2	11572.9	10591.6	11018.8	7946.1	5276.1	2431.2	2146.4	2405.0	6655.2	12294.2	18212.5
1942-43	18715.5	18921.0	17383.3	15708.2	14085.8	12560.8	7123.0	5867.4	3230.2	2851.3	3442.9	6276.3	12140.5	18232.3
1943-44	18798.7	19118.7	18306.0	17255.4	15168.9	12618.8	8358.6	5288.3	3117.5	2874.3	2874.3	5870.1	8201.2	10077.1
1944-45	10731.0	10780.5	8820.5	7795.4	5865.0	2729.7	1476.8	384.9	0.0	0.2	0.7	4093.7	11347.8	14800.0
1945-46	14789.9	14233.1	12474.0	11057.4	9607.1	7447.7	2330.9	1091.9	119.6	33.5	799.1	4294.8	14300.9	18815.8
1946-47	19119.2	19118.7	18457.6	17307.7	15645.3	12732.1	7372.6	3353.8	1379.9	1375.0	1660.8	6701.7	15461.5	18967.5
1947-48	19119.2	19070.8	18457.6	17437.2	15645.3	12732.1	7493.2	3265.7	1167.5	906.7	1295.0	4867.3	14926.2	18802.1
1948-49	19119.2	19118.7	18457.6	17437.2	15645.3	12732.1	7899.8	6915.1	4042.0	3487.4	3759.2	9993.1	15115.3	17468.5
1949-50	18298.4	18480.6	16961.5	15465.7	14597.1	12732.1	7368.7	3283.1	1882.9	1727.8	1986.1	5105.6	12241.1	19119.2
1950-51	19119.2	19118.7	18457.6	17437.2	15645.3	12732.1	7735.9	3710.8	2216.6	2202.9	2481.3	6302.7	13644.4	18815.8
1951-52	19119.2	19118.7	18457.6	17437.2	15645.3	12732.1	7371.4	3202.8	2153.5	1989.3	2918.8	7371.4	15176.7	18967.5
1952-53	19119.2	19048.5	17866.5	16082.5	13194.5	10186.7	5302.3	4022.9	2951.6	2327.7	2442.4	6008.4	14009.7	18482.6
1953-54	18715.5	19118.7	18457.6	17437.2	15645.3	12732.1	7516.4	3709.0	979.9	782.2	935.1	3491.5	12075.7	18774.2
1954-55	19119.2	19118.7	18457.6	17437.2	15645.3	12732.1	7633.6	4079.2	3040.6	2951.8	2166.0	4749.1	12361.2	18788.4
1955-56	19119.2	19118.7	18457.6	17437.2	15645.3	12732.1	7666.9	3376.3	1659.5	1578.8	1825.7	5314.5	15032.6	18967.5
1956-57	19102.8	19118.7	18457.6	17437.2	15645.3	12732.1	7420.8	3386.8	2089.4	2004.7	2287.1	5408.2	14106.6	17415.1
1957-58	17933.3	18157.0	16707.1	15631.8	13309.7	11374.5	6138.8	2238.9	1457.7	1574.1	1980.0	5403.6	15531.5	18646.0
Max	19119.2	19118.7	18457.6	17437.2	15645.3	12847.3	8358.6	6915.1	4905.2	5261.7	5941.8	11695.2	17089.7	19119.2
Median	18757.1	19018.5	17476.8	15864.6	13864.3	11967.7	7372.0	3630.8	1986.1	1858.6	2168.7	5876.1	13699.2	18564.3
Average	17486.3	17562.0	16394.8	15144.1	13212.8	10590.0	6148.3	3596.7	2036.4	1899.2	2209.2	6161.8	12908.0	17119.1
Min	9675.1	9347.7	7152.4	5645.8	3502.1	553.2	5.1	0.0	0.0	0.2	0.7	2934.2	7136.2	9695.9

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	2011-12 2012-13 /3
MICA TARGET OPERATION						
(hm^3 [xxxx.x] or m^3/s [xxx.xx])						
AUG 15	8561.1	8560.9	8451.0	8451.0	8414.3	8230.9
AUG 31	FULL	FULL	FULL	FULL	FULL	FULL
SEP	FULL	8622.1	FULL	FULL	FULL	FULL
OCT	8255.1	8181.7	8387.9	8387.9	8387.9	8387.9
NOV	566.34	651.29	566.34	622.97	594.65	594.65
DEC	651.29	707.92	707.92	707.92	707.92	707.92
JAN	707.92	736.24	679.60	651.29	764.55	679.60
FEB	594.65	622.97	594.65	566.34	594.65	594.65
MAR	538.02	566.34	509.70	481.39	594.65	481.39
APR 15	499.35	453.07	509.70	509.70	622.97	566.34
APR 30	424.75	368.12	339.80	311.49	283.17	283.17
MAY	283.17	283.17	283.17	283.17	226.53	226.53
JUN	283.17	283.17	283.17	283.17	226.53	226.53
JUL	8438.8	8438.6	8267.6	8407.0	8482.9	8482.9
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (hm^3)						
1928 AUG 31	19105.3	18785.7	19049.5	19111.9	19069.0	19118.7
1928 DEC	12756.1	12083.5	12560.4	12503.3	12443.4	12732.1
1929 APR15	3910.9	2268.2	2053.4	1642.9	2564.5	2653.1
1929 JUL	17813.0	17669.3	17487.6	17539.4	17696.7	17933.1
COMPOSITE CANADIAN TREATY STORAGE CONTENT (hm^3)						
60-Yr Average						
AUG 31	18141.5	17709.2	18008.7	18240.6	18197.7	18013.8
DEC	11644.6	10856.3	11339.7	11353.0	11286.0	11327.8
APR15	2685.6	2656.5	2883.3	2147.6	2061.6	2222.9
JUL	17767.2	17653.4	17600.1	17805.4	17784.1	17486.1
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)						
U.S. Firm Energy	-1.2	-0.1	-0.2	-0.3	-0.3	0.1
U.S. Dependable Peaking Capacity	16.0	-51.0	-21.0	-2.7	-19.1	-22.9
U.S. Average Annual Usable Secondary Energy	12.9	10.5	0.3	13.8	16.0	21.6
BCH Firm Energy	43.1	97.7	90.3	50.2	34.4	43.6
BCH Dependable Peaking Capacity	8.0	2.0	11.0	44.9	43.8	41.7
BCH Average Annual Usable Secondary Energy	-24.3	-55.7	-29.3	-28.2	-20.8	-13.9
COORDINATED HYDRO MODEL LOAD (MW)						
AUG 15	10439	11097	11137	11138	11138	10969
AUG 31	10435	11125	11165	11166	11167	11104
SEP	10101	10809	10849	10850	11025	11081
OCT	10186	9742	9782	9783	9958	9920
NOV	11807	10817	11157	11157	11333	11458
DEC	13377	12853	13192	13193	13369	13316
JAN	13122	12735	13075	13076	13076	12878
FEB	12240	11561	11901	11901	11902	11721
MAR	11175	11275	11315	11316	10967	10501
APR 15	10541	10550	10589	10590	10241	9786
APR 30	13065	14061	12822	12823	12475	11502
MAY	13752	14729	13491	13491	13493	13287
JUN	13114	14039	14079	14079	14080	13867
JUL	12079	12383	12723	12724	12725	12531
ANNUAL AVERAGE	11933	12034	12037	12038	12039	11855

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.
3/ The AOP/DDPB 2012-13 utilize the same system regulation studies as the 2011-12 AOP/DDPB.

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Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Canadian Projects					
Mica (1890)	Minimum Flow	3000 cfs	85.0 m^3/s		Treaty
Arrow (1831)	Minimum Flow	5000 cfs	141.6 m^3/s		Treaty
	Draft Rate Limit	1.0 ft/day	0.30 m/day		CRTOC Agreement
Duncan (1681)	Minimum Flow	100 cfs	2.8 m^3/s		CRTOC Agreement
	Maximum Flow	10000 cfs	283.2 m^3/s		CRTOC Agreement
	Draft Rate Limit	1.0 ft/day	0.30 m/day		CRTOC Agreement
	Other			Operate to meet IJC orders for Corra Linn.	CRTOC agreement on procedures to implement 1938 IJC order.
Base System					
Hungry Horse (1530)	Minimum Flow	400 cfs	11.3 m^3/s	Minimum project discharge.	In place in AOP79, AOP80, AOP84.
	Maximum Flow			None	
	Minimum Content			None	
	Other			No VECC limit.	VECC limit not in place in AOP79.
Kerr (1510)	Minimum Flow	1500 cfs	42.5 m^3/s	All periods	In place in AOP80, AOP84.
	Maximum Flow			None	
	Minimum Content	614.7 ksfd	1503.9 hm^3	Jun - Sep	MPC 2-1-92, PNCA submittal similar operation, Jun-Aug 15, in AOP80.
		2893.0 ft	881.79 m		
		426.3 ksfd	1043 hm^3	May	
		2890.0 ft	880.9 m		
		0.0 ksfd	0 hm^3	Empty Apr 15	FERC, AOP80.
		2883.0 ft	878.74 m		
	Maximum Content	58.6 ksfd	143.37 hm^3	March	In place in AOP80, AOP84.
		2884.0 ft	879.04 m	(Included to help meet the Apr 15 FERC requirement.)	
	Other	0.0 ksfd	0 hm^3	Conditions permitted, should be on or about, empty Mar and Apr 15.	FERC, AOP80.
		2883.0 ft	878.74 m		
Thompson Falls (1490)				None Noted	

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Noxon Rapids (1480)	Minimum Content				
	For Step I:	116.3 ksfd	284.54 hm^3	May - Aug 31,	In place in AOP84, similar operation in AOP80.
		2331.0 ft	710.49 m		
		112.3 ksfd	274.75 hm^3	Sep - Jan,	
		2330.0 ft	710.18 m		
		78.7 ksfd	192.55 hm^3	Feb,	
		2321.0 ft	707.44 m		
		26.5 ksfd	64.834 hm^3	Mar,	
		2305.0 ft	702.56 m		
		0.0 ksfd	0 hm^3	Empty Apr 15, Apr 30, and for end of CP.	
		2295.0 ft	699.52 m		
	Minimum & Maximum Content				
	For Steps II & III:	116.3 ksfd	284.54 hm^3	All periods	In place in AOP79, AOP84.
		2331.0 ft	710.49 m		
Cabinet Gorge (1475)				None Noted	
Albeni Falls (1465)	Minimum Flow	4000 cfs	113.3 m^3/s	All periods	In place in AOP80, AOP84.
	Minimum Content	(Dec may fill on restriction, note below)			
		582.4 ksfd	1424.9 hm^3	Jun - Aug 31	In place in AOP80, AOP84.
		2062.5 ft	628.65 m		
		465.7 ksfd	1139.4 hm^3	Sep	
		2060.0 ft	627.89 m		
		190.4 ksfd	465.83 hm^3	Oct	
		2054.0 ft	626.06 m		
		57.6 ksfd	140.92 hm^3	Nov-Apr 15	
		2051.0 ft	625.14 m		
		190.4 ksfd	465.83 hm^3	Apr 30 (empty at end of CP)	
		2054.0 ft	626.06 m		
		279.0 ksfd	682.59 hm^3	May	
		2056.0 ft	626.67 m		
	For Steps I & II:	Optimum to run CP & LT to Jun-Oct SMINs.			
	For Step III:	Keep full at beginning of CP. Often (not always) optimum to run higher than SMIN in CP & LT (except when occasionally drafting below SMIN to meet load).			
		57.6 ksfd	140.9 hm^3	Nov - Mar	
		2051.0 ft	625.14 m		
		458.4 ksfd	1121.5 hm^3	May	
		2059.8 ft	627.8 m		
		582.4 ksfd	1424.9 hm^3	Sep	
		2062.5 ft	628.7 m		
		465.7 ksfd	1139.4 hm^3	Oct	
		2060.0 ft	627.89 m		

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	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	
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	0.0 hm^3	Empty at end of CP.	
		1208.0 ft	368.20 m		
	Step I only:	843.9 ksfd	2064.7 hm^3	May and June	Retain as a power operation (for pumping).
		1240.0 ft	377.95 m		
	Steps II & III only:	857.9 ksfd	2098.9 hm^3	May and June	
		1240.0 ft	378.0 m		
	Maximum Content				
	Step I only:	2.0 ft	0.61 m	Operating room Sep - Nov	In place in AOP89
		3.0 ft	0.91 m	Operating room Dec - Feb	Retain as a power operation.
	Steps II & III only:	2557.1 ksfd	6256.1 hm^3	Aug-Nov	
		1288.0 ft	392.58 m		
		2518.3 ksfd	6161.2 hm^3	Dec-Feb	
		1287.0 ft	392.28 m		
	Draft Rate Limit	1.3 ft/day	0.40 m/day	(bank sloughage)	
		1.5 ft/day	0.46 m/day	(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

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Priest Rapids (1160)	Minimum Flow			Limit removed	
	Fish Spill/Bypass			None	
	Other Spill	2200 cfs	62.3 m^3/s	All periods	With fish ladder
Brownlee (767)	Minimum Flow	5850 cfs	165.7 m^3/s	All years, all periods in CP & LT studies.	4-04 C. Henriksen
	Downstream Minimum Flow	13000 cfs	368.1 m^3/s	July-Sep in all years for navigation requirement downstream at Lime Point (project #760). Draft Brownlee to help meet this requirement in CP and LT studies.	4-04 C. Henriksen
	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	

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	Other				
	Step I:	269.7 ksfd	659.8 hm^3	June - Aug 15	In place AOP80
		268.0 ft	81.69 m		
		242.5 ksfd	593.3 hm^3	Aug 31 - Sep	
		267.0 ft	81.38 m		
		153.7 ksfd	376.0 hm^3	Oct - Mar	
		263.6 ft	80.35 m		
		114.9 ksfd	281.1 hm^3	Apr - May	
		262.0 ft	79.86 m		
	Steps II & III:	190.0 ksfd	464.8 hm^3	Use JDA as run-of-river plant.	
		265.0 ft	80.77 m		
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	1415.8 m^3/s	Mar - Nov	
		12500 cfs	354.0 m^3/s	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	275.2 hm^3	May - Aug	
		2128.0 ft	648.6 m	Flood control may override these minimum contents.	2-1-00 PNCA submittal
Post Falls (1340)	Minimum Flow	50 cfs	1.4 m^3/s	All periods	In place in AOP79, AOP80, AOP84.
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	

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Minimum Content	By contract year: Aug-Jul i.e., 1929 = Aug 1928 - Jul 1929			
	776.9 ksfd	1900.7 hm^3	1929 Dec	2-1-93 PNCA submittal, in place in AOP99.
	2363.0 ft	720.24 m		
	676.5 ksfd	1655.1 hm^3	1929 Jan	
	2355.0 ft	717.80 m		
	603.6 ksfd	1476.8 hm^3	1929 Feb	
	2349.0 ft	715.98 m		
	2147.7 ksfd	5254.5 hm^3	1929 Jul	
	2443.0 ft	744.63 m		
	652.0 ksfd	1595.2 hm^3	1930 Dec	
	2353.0 ft	717.19 m		
	433.2 ksfd	1059.9 hm^3	1930 Jan	
	2334.0 ft	711.40 m		
	389.3 ksfd	952.5 hm^3	1930 Feb	
	2330.0 ft	710.18 m		
	348.5 ksfd	852.6 hm^3	1930 Mar	
	2326.0 ft	708.96 m		
	297.4 ksfd	727.6 hm^3	1930 Apr 15	
	2321.0 ft	707.44 m		
	444.2 ksfd	1086.8 hm^3	1930 Apr 30	
	2335.0 ft	711.71 m		
	499.1 ksfd	1221.1 hm^3	1930 May	
	2340.0 ft	713.23 m		
	1344.6 ksfd	3289.7 hm^3	1930 Jun	
	2402.0 ft	732.13 m		
	1771.9 ksfd	4335.1 hm^3	1930 Jul	
	2425.0 ft	739.14 m		
	317.8 ksfd	777.5 hm^3	1931 Dec	
	2323.0 ft	708.05 m		
	192.2 ksfd	470.2 hm^3	1931 Jan	
	2310.0 ft	704.09 m		
	103.1 ksfd	252.2 hm^3	1931 Feb-Apr 30	
	2300.0 ft	701.04 m		
	192.2 ksfd	470.2 hm^3	1931 May	
	2310.0 ft	704.09 m		
	676.5 ksfd	1655.1 hm^3	1931 Jun	
	2355.0 ft	717.80 m		
	868.0 ksfd	2123.6 hm^3	1931 Jul	
	2370.0 ft	722.38 m		
	174.4 ksfd	426.7 hm^3	1932 Dec	
	2308.0 ft	703.48 m		
	103.1 ksfd	252.2 hm^3	1932 Jan	
	2300.0 ft	701.04 m		
	0.0 ksfd	0.0 hm^3	Empty at end of CP	
	2287.0 ft	697.08 m		
	776.9 ksfd	1900.7 hm^3	All Dec	
	2363.0 ft	720.24 m		
		0.0 hm^3		
	373.1 ksfd	152.5 hm^3	July 1930 - No more than this amount lower than July 1929.	2-1-94 PNCA submittal, in place in AOP00 and AOP01.
	857.1 ksfd	350.3 hm^3	July 1931 - No more than this amount lower than July 1930.	
	March - Implement PNCA 6(c)2(c).			

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	Max Summer Draft	5.0 ft	1.52 m		
	Other			Operate to meet IJC orders for Corra Linn.	CRTOC agreement on procedures to implement 1938 IJC order.
Dworshak (535)	Minimum Flow	1300 cfs	36.8 m^3/s	All periods	2-11-02 PNCA submittal
	Maximum Flow	14000 cfs	396.4 m^3/s	All periods (model includes maximum 14000 cfs for all periods, but URC may override.)	2-11-02 PNCA submittal
		25000 cfs	707.9 m^3/s	Up to 25 kcfs for flood control all periods.	
	Start CP at:	642.4 ksfd	1571.7 hm^3	Aug 15	
	End 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
		1573.2 ft	479.51 m		Jul-Aug 15 and Sep based
		642.4 ksfd	1571.7 hm^3	Aug 15	on 60 Median .
		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	14.158 m^3/s	Jul - Oct	2-1-05 PNCA submittal
		400 cfs	11.327 m^3/s	Nov - Dec	
		100 cfs	2.8317 m^3/s	Jan	
		200 cfs	5.6634 m^3/s	Feb- Mar	
		460 cfs	13.026 m^3/s	Apr 15 - Jun	
	Incremental Spill			Removed	
	Fish Spill				
		17333 cfs	490.8 m^3/s	Apr 15 [20 kcfs alternating for 13 days]	2-1-06 PNCA submittal
		20000 cfs	566.3 m^3/s	Apr 30 - May	
		19333 cfs	547.4 m^3/s	June [20 kcfs for 20 day and 18 kcfs for 10 days]	
		18000 cfs	509.7 m^3/s	July - Aug 31	

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	Maximum Fish Spill	20000 cfs	566.3 m^3/s	Apr 15 - Jun		
		18000 cfs	509.7 m^3/s	Jul - Aug 31		
	Minimum Flow	11500 cfs	325.6 m^3/s	All periods		
	Other	224.9 ksfd	550.2 hm^3	On MOP Apr - Oct 31.		
		733.0 ft	223.42 m			
		245.8 ksfd	601.4 hm^3	On full pool Nov 30 - Mar 31.		
		738.0 ft	224.94 m			
Little Goose (518)	Bypass Date			None		
	Other Spill	600 cfs	17.0 m^3/s	Jul - Nov		2-1-05 PNCA submittal
		450 cfs	12.7 m^3/s	Dec		
		150 cfs	4.2 m^3/s	Jan		
		300 cfs	8.5 m^3/s	Feb - Mar		
		600 cfs	17.0 m^3/s	Apr 15 - Jun		
	Incremental Spill			Removed		
	Fish Spill (% of outflow)	26%		Apr 15	[.30*13/15]	2-1-06 PNCA submittal
		30%		Apr 30 - Aug 31		
	Maximum Fish Spill	25000 cfs	707.9 m^3/s	Apr 15 - Apr 31		
		30000 cfs	849.5 m^3/s	May - Aug 31		
	Minimum Flow	11500 cfs		All periods		
	Other	260.5 ksfd	106.5 hm^3	On MOP Apr - Aug 31.		
		633.0 ft	192.94 m			
		285.0 ksfd	697.3 hm^3	On full pool Sep 30 - Mar 31.		
		638.0 ft	194.46 m			
Lower Monumental (504)	Bypass Date			A bypass date of 2010 was assumed.		
	Other Spill	850 cfs	24.1 m^3/s	Jul - Oct		2-1-05 PNCA submittal
		750 cfs	21.2 m^3/s	Nov		
		600 cfs	17.0 m^3/s	Dec		
		300 cfs	8.5 m^3/s	Jan - Feb		
		500 cfs	14.2 m^3/s	Mar		
		850 cfs	24.1 m^3/s	Apr 15 - Jun		
	Fish Spill	19067 cfs	539.9 m^3/s	Apr 15	[22*(13/15)]	2-1-06 PNCA submittal
		22000 cfs	623.0 m^3/s	Apr 31 - May		
		20333 cfs	575.8 m^3/s	Jun	[22*(20/30) + 17*(10/30)]	
		17000 cfs	481.4 m^3/s	Jul - Aug 31		

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	Maximum Fish Spill	22000 cfs	623.0 m^3/s	Apr 15 - Jun	
		17000 cfs	481.4 m^3/s	Jul - Aug 31	
	Minimum Flow	11500 cfs	325.6 m^3/s	All period	
	Other	180.5 ksfd	441.6 hm^3	On MOP Apr - Aug 31.	
		537.0 ft	163.68 m		
		190.1 ksfd	465.1 hm^3	On full pool Sep 30 - Mar 31.	
		540.0 ft	164.59 m		
Cushman (2206)	Other Spill	100 cfs	2.8 m^3/s	All periods	
LaGrande (2188)	Other Spill	30 cfs	0.8 m^3/s	All periods	
White River (2160)	Other Spill	130 cfs	3.7 m^3/s	All periods	
Lower Baker (2025)	Max Storage Limits	67.0 ksfd	163.9 hm^3	Jul - Aug 31	2-1-05 PNCA submittal
		442.4 ft	134.84 m		
		40.1 ksfd	98.1 hm^3	Sep	
		415.9 ft	126.77 m		
		34.7 ksfd	84.9 hm^3	Oct - Dec	
		409.8 ft	124.91 m		
		45.2 ksfd	110.6 hm^3	Jan - Mar	
		421.4 ft	128.44 m		
		46.7 ksfd	114.3 hm^3	Apr 15	
		423.0 ft	128.93 m		
		67.0 ksfd	163.9 hm^3	Apr 30 - Jun	
		442.4 ft	134.84 m		
		11.2 ksfd	27.4 hm^3	All periods	
		378.8 ft	115.46 m		
Upper Baker (2028)	Max Storage Limits	107.4 ksfd	262.8 hm^3	Jul - Sep	2-1-05 PNCA submittal
		727.8 ft	221.83 m		
		82.3 ksfd	201.4 hm^3	Oct	
		717.0 ft	218.54 m		
		70.9 ksfd	173.5 hm^3	Nov - Feb	
		711.7 ft	216.93 m		
		107.4 ksfd	262.8 hm^3	Mar - Jun	
		727.8 ft	221.83 m		
	Min Storage Limits	69.3 ksfd	169.5 hm^3	Jul - Aug 31	
		710.8 ft	216.65 m		
		65.6 ksfd	160.5 hm^3	Sep - Oct	
		708.8 ft	216.04 m		
		16.6 ksfd	40.6 hm^3	Nov - Mar	
		677.8 ft	206.59 m		
		38.0 ksfd	93.0 hm^3	Apr 15 - Apr 30	
		693.8 ft	211.47 m		
		69.3 ksfd	169.5 hm^3	May - Jun	
		710.8 ft	216.65 m		

Appendix A
Project Operating Procedures for the 2012-13
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.

Timothy (117)	Minimum Content	24.5 ksfd	59.9 hm^3	Oct - May	3-6-01 PNCA submittal
		3180.0 ft	969.26 m		
		31.1 ksfd	76.1 hm^3	Jun - Aug 31	
		3190.0 ft	972.31 m		
		27.8 ksfd	68.0 hm^3	Sep [(24.5*15+31.1*15)/30]	
		3185.0 ft	970.79 m		
Long Lake (1305)	Minimum Content	50.1 ksfd	122.6 hm^3	Apr - Nov	2-5-02 PNCA submittal
		1535.0 ft	467.87 m		
		19.7 ksfd	48.2 hm^3	Dec - Mar	
		1522.0 ft	463.9 m		
	Draft Rate Limit	1.0 ft/day	0.30 m/day		2-1-03 PNCA submittal
Priest Lake (1470)	Maximum Content	0.0 ksfd	0.0 hm^3	Oct	2-1-03 PNCA submittal
		0.0 ft	0.00 m		
	Max/Min Content	35.5 ksfd	86.9 hm^3	Maintain at or near after runoff through Sep.	
		3.0 ft	0.91 m		
Ross (2070)	Minimum Content/			Dependent on Skagit Fisheries.	2-1-06 PNCA submittal
Gorge (2065)	Minimum Flow			Settlement; monthly data, varies by water year.	2-1-06 PNCA submittal

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 2012-13

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DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB)
FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 2012-13

January 2008

1. Introduction

The "Treaty between Canada and the United States of America relating to the Cooperative Development of the Water Resources of the Columbia River Basin" (Treaty), dated 17 January 1961, 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 2012-13 Determination of Downstream Power Benefits (DDPB13).

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 - Annex to Exchange of Notes, Dated January 22, 1964 Between the Governments of Canada And the United States Regarding the Columbia River Treaty" (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, and except for changes noted below, including the update to Appendix 1, dated 18 November 2003, 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 Treaty, the Protocol, and the "Columbia River Treaty Flood Control Operating Plan" (FCOP), dated May 2003. For this DDPB, the Entities have agreed to use the streamline methods defined in Appendix 6 of the POP:

- "Forecasting Loads and Resources," for determining the thermal installations described in Subsection 7(d) of the AOP13;

- "Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage," for use of the AOP12 US and Joint Optimum Step I System Regulation studies, as explained in Subsection 2(a) of the AOP13;

- "Monthly Hydro Energy Reshaping for Steps II and III 30-year System Regulation Studies," as described in Subsection 6(f) of this DDPB13.

In addition, the Entities have agreed on the following modifications to the streamline methods:

- Allocate available uncommitted PNWA resources and available uncommitted imports from Canada and California, together with a seasonal exchange, to balance the White Book (WB) deficit, as described in Subsection 7(b) of the AOP13; and

- Modify the Determination of Downstream Power Benefits (DDPB) Table 2 calculation of Thermal Displacement Market to use thermal imports (i.e. not Canadian Entitlement (CE) or Skagit Treaty power) to support exports (not including CE, plant sales, flow-through-transfers (FTT), seasonal exchanges (SE) or excess extra-regional thermal installations), on an annual basis, as either FTT's or SE's.

The Canadian Entitlement Benefits were computed from the following studies:

Step I -- Operation of the total USA Columbia Basin hydro and thermal system, with 19.12 cubic kilometers[1] (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 DDPB, 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 2012-13 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	= 1320.8 megawatts (MW)
Average Annual Usable Energy	= 504.5 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 1.5 average megawatt (aMW) increase in the Energy Entitlement and no change to the Capacity Entitlement (See Table 5, columns A and B), compared to Step II studies based on optimum power generation only in the USA. Since there was no reduction in the downstream power benefits in the 2012-13 DDPB, the computation of the maximum allowable reduction in downstream power benefits, as defined in Section 3.3 A(3) of the POP, was not performed.

4. Delivery of the Canadian Entitlement

See Section 6 of the AOP13.

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 and modified according to the streamline process noted in the Introduction and described in Subsection 7(b) of the AOP13. Based on this modified streamline procedure for allocating available uncommitted resources and uncommitted imports, 53% of the estimated CE returned to Canada becomes a firm import to the PNWA and no imports from California

are added. Table 1A shows the Step I energy loads and resources developed for AOP13, with a similar regulated hydro load as in the AOP12 and 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) and modified as noted in the Introduction.

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 ratios between each month and the annual average as the PNWA load (to maintain the same annual load shape). The PNWA firm loads were based on the Bonneville Power Administration (BPA) 2007 White Book (WB07) load forecast as described in Subsection 7(a) of the AOP13. 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 2012-13 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 transmission losses and reserves in the Step I system load as an adjustment to resources. This table is modified to reflect the roll-over of Step I hydro information from AOP12 and results of the streamline process for Steps II and III with the exception of the critical period average that comes from the AOP13 Steps II and III Critical Period studies.

Table 5 Computation of Canadian Entitlement for 2012-13 Assured Operating Plan:

A. Joint Optimum Generation in Canada and the USA
B. Optimum Generation in the USA Only

The essential elements used in the computation of the Canadian Entitlement arising from the downstream power benefits under the Joint Optimum and USA Optimum are shown under Columns A and B, respectively. These elements are derived from (1) Steps II and III critical period studies based on the load shape from the AOP 13 studies, (2) the Thermal Displacement Market from the AOP13 studies and (3) the Steps II and III 30-year Hydroregulation Studies based on the AOP12 with revisions to reshape generation to the 2012-13 Steps II and III loads as described in Subsection 6(f). The computation of maximum allowable reduction in

downstream power benefits are not shown in this table because that calculation is not necessary (as explained in Section 3).

Table 6 Comparison of Recent DDPB Studies

Chart 1 Duration Curves of 30 Years Monthly Hydro Generation:

This chart shows duration curves of the hydro generation in aMW from the Steps II and III system regulation studies[2], 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 2011-12 AOP and Notable Assumptions

Data from recent DDPBs are summarized in Table 6. The following is an explanation of the more important changes and notable assumptions that impact computation of the entitlement compared to the 2011-12 DDPB (DDPB12) studies.

a) Steps II and III Firm Loads

The Steps II and III hydro loads shown on Table 3 are noticeably different from the DDPB12, with generally lower levels during July through February and higher levels March through June. The large difference is mainly due to increases in the amount of thermal generation.

The average critical period load factor decreased from 76.07% in AOP12 (WB06) to 74.85% in AOP13 (WB07). This was mainly due to changes in the peak load forecast.

b) Thermal Installations

The Thermal Installation energy capability shown in Table 3 increased by 571.6 annual aMW compared to the DDPB12. This is largely due to the increase in Step I firm load.

The Thermal Displacement Market (TDM) increased by 579.2 annual aMW, mainly due to the increased thermal installations, but also due to the use of thermal imports to support exports (23.2 annual aMW), as described in the Introduction.

c) Hydro Project Modified Stream Flows

The base unregulated stream flows used in the Steps II and III System Regulation Studies are the same as the Step I studies (see Subsection 7(e) of AOP13), except for adjustments to add the effect of natural lake regulation and remove reservoir evaporation at projects not included in Steps II/III.

d) Hydro Project Rule Curves

In accordance with the Streamline Procedure "Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage", the critical rule curves, refill curves, and Mica/Arrow operating criteria were retained from AOP12. Some of the more notable assumptions are described in Subsection 7(f) of the AOP13.

e) Other Hydro Project Operating Procedures, Constraints, and Plant Data

In accordance with the Streamline Procedure "Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage", the AOP13 hydro project operating procedures, constraints, and plant data are retained from the AOP12. Some of the more notable assumptions are described in Subsection 7(g) of the AOP13.

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

Step II and Step III critical period regulation studies for the 2012-13 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 stream flow periods were unchanged from the DDPB12 studies. The Step II critical period comprised the 20 calendar-months from 1 September 1943 through 30 April 1945, and the Step III critical period included the 5.5 calendar-months from 1 November 1936 through 15 April 1937. The Step II critical period study showed a small decrease in average critical period generation (4 aMW) and average annual firm energy (5 aMW), and the Step III critical period showed an increase in average critical period generation (17.4 aMW) and average annual firm energy (3.7 aMW), both due mainly to changes in the hydro load shape. All of these changes in critical period generation and firm energy have the effect of reducing the Canadian Entitlement.

For the 30-year System Regulation Studies, the Entities agreed to a Streamline Method that uses the 2011-12 Steps II (-42 and -12) and III (-13) 30-year System Regulation Studies, together with a month-to-month generation reshaping procedure, to estimate Steps II and III 30-year average annual usable hydro energy for this DDPB. The procedure reshaped the 2011-12 Steps II and III 30-year hydro system generation to meet the 2012-13 firm hydro loads.

g) Downstream Power Benefits

The Canadian Capacity Entitlement increased from 1314.0 MW in the DDPB12 to 1320.8 MW in the DDPB13, an increase of 6.8 MW. This change was mainly due to a decrease in the average critical period load factor, from 76.07% to 74.85%.

The Canadian Energy Entitlement decreased from 525.9 annual aMW in the DDPB12 to 504.5 annual aMW in the DDPB13 for a decrease of 21.4 annual aMW. The change was mainly due to the 579.2 annual aMW increase in the TDM and to a small extent due to the change in the annual shape of the thermal installation generation which increased Step III useable energy.

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

2 The Steps II and III DDPB13 streamlined system estimates, dated 15 November 2007 and prepared by BPA, were used to determine the critical period and 30-year system generation.

TABLE 1A
2012-13 ASSURED OPERATING PLAN
DETERMINATION OF FIRM ENERGY HYDRO LOADS FOR STEP I STUDIES
(Energy in Average MW)

	Aug15	Aug31	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	Jun	Jul	Ann. Avg.	CP Avg. 1/
1. Pacific Northwest Area (PNWA) Firm Load																
a) White Book Regional Firm Load 2/	22523	22518	21166	21317	23549	25655	26104	25094	23242	21973	21958	21352	21966	23097	23079	23176
b) Exclude 99% of UPL's Idaho load 3/	-481	-481	-447	-447	-446	-479	-449	-463	-433	-409	-409	-458	-529	-584	-469	-467
c) Adjustment to Coulee pumping 4/	10	-10	1	9	4	-5	22	27	4	3	0	-7	-1	0	4	5
d) …Total PNWA Firm Loads	**22052**	**22027**	**20720**	**20879**	**23107**	**25171**	**25676**	**24658**	**22813**	**21567**	**21549**	**20888**	**21436**	**22513**	**22615**	**22714**
e) Annual Load Shape in Percent	97.5	97.4	91.6	92.3	102.2	111.3	113.5	109.0	100.9	95.4	95.3	92.4	94.8	99.5	100.0	100.4
2. Flows-Out of firm power from PNWA																
a) White Book Exports 5/	1146	1146	1095	860	813	851	847	842	876	876	784	703	927	1080	906	906
b) Remove WB Canadian Entitlement	-505	-505	-505	-505	-505	-505	-505	-505	-505	-505	-505	-505	-505	-505	-505	-505
c) Add est. Can. Entitle. Exported 6/	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
d) Added Seasonal Exchange Export 7/	0	29	1392	356	0	0	0	0	0	0	0	1041	2838	1205	570	524
e) Imp. Thermal used out of region 8/	229	257	230	148	95	0	43	88	107	100	62	124	176	185	127	125
f) …Subtotal for Table 2	1370	1427	2712	1360	903	846	885	925	978	971	841	1862	3936	2466	1598	1550
g) Remove Plant Sales	-175	-176	-183	-185	-189	-184	-181	-176	-211	-182	-174	-57	-195	-188	-175	-176
h) Remove Flow-through-transfer	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75	-60	-59
i) …Total	**1119**	**1177**	**2454**	**1130**	**669**	**617**	**660**	**705**	**722**	**714**	**593**	**1730**	**3666**	**2203**	**1363**	**1315**
3. Flows-In of firm power to PNWA, except from coordinated thermal installations																
a) White Book Imports 9/	-718	-689	-683	-736	-998	-1176	-1057	-1010	-805	-742	-738	-694	-808	-872	-856	-866
b) Remove UP&L imports for 1(b)	481	481	447	447	446	479	449	463	433	409	409	458	529	584	469	467
c) Remove Thermal Installations 10/	121	93	121	202	255	348	307	263	199	190	211	128	159	164	204	209
d) Add Can. Import for WB deficits 11/	-265	-265	-265	-265	-265	-265	-265	-265	-265	-265	-265	-265	-265	-265	-265	-265
e) Add Seasonal Exchanges 7/	-105	0	0	0	-39	-384	-1453	-1787	-2067	-1817	-468	0	0	0	-570	-568
f) Remove Flow-Through-Xfers	75	75	75	45	45	45	45	45	45	75	75	75	75	75	60	59
g) …Total	**-411**	**-306**	**-304**	**-307**	**-556**	**-953**	**-1975**	**-2291**	**-2460**	**-2151**	**-776**	**-298**	**-309**	**-313**	**-958**	**-964**
4. PNWA Non-Step I Hydro and Non-Thermal Resources																
a) Hydro Independents (1929 water)	-996	-996	-1026	-1088	-1130	-1065	-1015	-845	-946	-1163	-1116	-1432	-1392	-1112	-1100	-978
b) Non-Step I Coordinated Hydro (1929)	-509	-456	-561	-944	-916	-962	-956	-490	-731	-767	-763	-742	-1316	-638	-793	-820
c) WB07 NUG Renewables	-258	-258	-250	-267	-308	-275	-287	-255	-372	-295	-296	-302	-299	-273	-287	-285
d) WB07 Regional Hydro NUGs	-308	-306	-229	-152	-111	-104	-94	-99	-130	-259	-268	-389	-421	-403	-226	-214
e) WB07 Renewables	-262	-262	-250	-239	-234	-197	-174	-173	-364	-279	-279	-308	-322	-296	-259	-252
f) …Total (1929)	**-2334**	**-2279**	**-2317**	**-2691**	**-2700**	**-2603**	**-2526**	**-1862**	**-2544**	**-2764**	**-2721**	**-3173**	**-3750**	**-2722**	**-2665**	**-2548**
5. Step I System Load (1929) 12/	**20427**	**20619**	**20553**	**19012**	**20520**	**22232**	**21836**	**21210**	**18532**	**17366**	**18644**	**19146**	**21042**	**21681**	**20355**	**20517**
6. Coordinated Thermal Installations 13/																
a) Columbia Generation Station (WNP2)	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	332	0	930	878	901
b) Generic Thermal Installations	9622	9621	9666	9636	9624	9577	9628	9665	8402	7954	7509	6929	9216	9605	9104	9185
c) ...Total	**10652**	**10651**	**10696**	**10666**	**10654**	**10607**	**10658**	**10695**	**9432**	**8984**	**8539**	**7261**	**9216**	**10535**	**9982**	**10086**
7. Step I Hydro Resources (1929) 14/	**10456**	**10644**	**10516**	**8972**	**10537**	**12349**	**11917**	**11227**	**9766**	**9016**	**10734**	**12541**	**12545**	**11889**	**11058**	**11116**
8. Step I Resource Adjustments																
a) Hydro Maintenance	-30	-25	-9	-9	-4	0	0	0	-5	-7	-8	-20	-14	-49	-12	-11
b) Transmission System Losses 15/	-650	-651	-650	-618	-667	-724	-739	-712	-661	-625	-621	-635	-705	-694	-673	-674
9. Total Step I System Resources(1929)	**20427**	**20619**	**20553**	**19012**	**20520**	**22232**	**21836**	**21210**	**18532**	**17366**	**18644**	**19146**	**21042**	**21681**	**20355**	**20517**
10. Coordinated Hydro Load (1929) 16/	**10965**	**11100**	**11077**	**9916**	**11453**	**13311**	**12873**	**11717**	**10497**	**9783**	**11497**	**13283**	**13861**	**12527**	**11851**	**11936**
a) Coord. Hydro Load Shape (1929) 17/	92.5%	93.7%	93.5%	83.7%	96.6%	112.3%	108.6%	98.9%	88.6%	82.5%	97.0%	112.1%	117.0%	105.7%	100.0%	

Notes:

1/ The Step I critical period is the 42.5 months beginning 16 August 1928 and ending 29 February 1932.
2/ BPA March 2007 White Book (WB07) total regional firm load estimate, that includes estimated Coulee pumping and Idaho loads served by Utah P&L.
3/ Annex B requires exclusion of Idaho load (and corresponding import) from area served by Utah Power Light in 1964.
4/ Although a minor change, Coulee pumping loads were updated to the 2007 PNCA data submittal to be consistent with the pumping flows in the Base Flows.
5/ WB07 exports include Firm Seasonal Exchanges, Flow-Through Transfers, Plant Sales, and an estimate of the Canadian Entitlement.
6/ Assumes 500 MW Energy Entitlement exported to Canada.
7/ Added Seasonal Exchange which balances annually. See lines 2(d) and 3(e).
8/ Added thermal export to balance difference between thermal import and equivalent thermal installation based on generic annual shape.
9/ White Book Imports include coordinated thermal installations, seasonal & capacity exchanges, flow-through-transfers, and Skagit Treaty power.
10/ Imports identified as coordinated thermal installations are excluded, to be replaced by a portion of the Generic Thermal Installations.
11/ Added Canadian import as a portion of the resources needed to balance WB deficits, based on 53% of estimated 500 aMW of Energy Entitlement .
12/ Line 1(d) + line 2(i) + line 3(g) + line 4(f), based on 1929 hydro independent capability
13/ Thermal installations are CGS, plus a generic thermal installation that is sized to meet the Step 1 System load minus Step I Hydro.
14/ Step I Hydro (US hydro projects at and upstream of Bonneville Dam) critical period capability shaped to 1929 load, line 5 minus line 6(c), 8(a), & 8(b).
15/ Transmission losses are 2.67% of all resources including imports.
16/ The Coordinated Hydro Model Load is the Step I Hydro Resources plus Non-Step I Coordinated Hydro, lines 7 - 4(b).
17/ The Coordination Hydro Model Load Shape shows the net effect of loads and nonhydro resources on the coordinated system hydro resources.

TABLE 1B
2012-13 ASSURED OPERATING PLAN
DETERMINATION OF FIRM PEAK HYDRO LOADS FOR STEP I STUDIES
(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	29441	29433	27619	29631	32779	35199	35914	34534	31617	29384	29396	28651	28859	30228
b) Exclude 99% of UPL's Idaho load	-523	-523	-481	-481	-487	-509	-480	-493	-459	-436	-436	-506	-606	-641
c) Remove Federal Peak Diversity 1/	-523	-562	-599	-426	-379	-615	-387	-400	-455	-572	-593	-599	-548	-443
d) Updates to Coulee pumping forec.	10	-10	1	0	0	0	0	0	0	240	213	220	254	236
e) ….Total PNWA Firm Loads	**28405**	**28339**	**26540**	**28724**	**31913**	**34075**	**35047**	**33641**	**30702**	**28616**	**28580**	**27766**	**27959**	**29380**
f) Monthly Load Factors in Percent	77.64	77.73	78.07	72.69	72.41	73.87	73.26	73.30	74.30	75.37	75.40	75.23	76.67	76.63
2. Flows-Out of firm power from PNWA														
a) White Book Exports	2236	2237	2242	1848	1728	1724	1719	1715	1749	1749	1749	1726	2234	2229
b) Remove WB Canadian Entitlement	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350
c) Add estimated Can.Entitle. exported	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350
d) Added Seasonal Exch. Export	0	29	1392	356	0	0	0	0	0	0	0	1041	2838	1205
e) Thermal Inst. used outside region 2/	246	281	254	184	88	-31	21	68	113	115	82	159	154	211
f) …Subtotal for Table 2	*2483*	*2547*	*3888*	*2388*	*1816*	*1693*	*1739*	*1783*	*1862*	*1864*	*1831*	*2926*	*5227*	*3645*
g) Remove Plant Sales	-118	-118	-118	-118	-118	-118	-118	-118	-118	-118	-118	0	-118	-118
h) Remove Flow-through-transfer	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75
i) …Total	**2290**	**2354**	**3695**	**2195**	**1623**	**1500**	**1547**	**1590**	**1670**	**1671**	**1638**	**2851**	**5034**	**3452**
3. Flows-In of firm power to PNWA, except from coordinated thermal installations														
a) White Book Imports	-931	-896	-881	-923	-1306	-1485	-1436	-1438	-1034	-910	-926	-923	-1088	-1084
b) Exclude UP&L imports for 1(b)	528	528	486	486	492	514	485	498	464	440	440	511	613	647
c) Remove Thermal Install Imports	181	146	174	245	342	456	406	362	268	236	252	190	254	216
d) Add Canadian Import for WB deficits	-716	-716	-716	-716	-716	-716	-716	-716	-716	-716	-716	-716	-716	-716
e) Add Seasonal Exch. Imports	-105	0	0	0	-39	-384	-1453	-1787	-2067	-1817	-468	0	0	0
f) Remove Flow-Through-Transfer	75	75	75	45	45	45	45	45	45	75	75	75	75	75
g) …Total	**-967**	**-862**	**-862**	**-863**	**-1181**	**-1569**	**-2669**	**-3036**	**-3039**	**-2692**	**-1342**	**-862**	**-862**	**-862**
4. PNWA Non-Step I Hydro and Non-thermal Resources														
a) Hydro Independents (1937 water)	-1785	-1764	-1756	-1675	-1595	-1586	-1546	-1654	-1758	-1841	-1847	-1916	-1933	-1840
b) Non-Step I Coordinated Hydro (1937)	-2508	-2430	-2529	-2464	-2365	-2292	-1501	-1330	-2024	-2039	-2088	-2172	-2315	-2498
c) WB07 NUG Renewables	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55
d) WB07 Regional Hydro NUGs	-359	-357	-287	-205	-147	-135	-127	-138	-174	-287	-297	-422	-438	-429
e) WB07 Renewables	-19	-19	-19	-17	-15	-13	-12	-12	-13	-15	-15	-67	-18	-20
f) …Total (1937)	**-4726**	**-4625**	**-4646**	**-4416**	**-4177**	**-4081**	**-3241**	**-3190**	**-4024**	**-4236**	**-4301**	**-4632**	**-4759**	**-4841**
5. Step I System Load (1937) 3/	**25002**	**25206**	**24728**	**25641**	**28177**	**29925**	**30684**	**29006**	**25309**	**23359**	**24574**	**25123**	**27372**	**27129**
6. 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	11750	11750	11766	11793	11820	11706	11728	11825	10480	9629	9171	9605	11229	11729
c) ...Total	**12900**	**12900**	**12916**	**12943**	**12970**	**12856**	**12878**	**12975**	**11630**	**10779**	**10321**	**9605**	**11229**	**12879**
7. Step I Hydro Resc. needed (1937) 4/	**21603**	**21187**	**20610**	**20826**	**23149**	**24106**	**24410**	**23330**	**21076**	**19753**	**21004**	**22366**	**23550**	**23140**
8. Step I Resource Adjustments														
a) Hydro Maintenance 5/	-4595	-4032	-3787	-3208	-2935	-2037	-1561	-2286	-2626	-2751	-2483	-2360	-2202	-3720
b) Transmission System Losses 6/	-969	-972	-958	-980	-1055	-1113	-1179	-1144	-1046	-966	-941	-970	-1047	-1042
c) Reserves (approx 11%) 7/	-3937	-3877	-4054	-3940	-3952	-3886	-3863	-3871	-3725	-3456	-3327	-3519	-4157	-4128
9. Required Step I Resources (1937)	**25002**	**25206**	**24728**	**25641**	**28177**	**29925**	**30684**	**29006**	**25309**	**23359**	**24574**	**25123**	**27372**	**27129**
10. Coordinated Hydro Load (1937) 8/	24111	23617	23139	23290	25514	26398	25911	24660	23100	21792	23092	24538	25865	25638

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.

3/ Total Step I Firm Peak Load is the sum of lines 1e + 2i + 3g + 4f

4/ Step I hydro resources needed to meet the load = line 5 minus lines 6c, 8a, 8b, & 8c. Actual resource capability is higher.

5/ From WB07, based on 5-year PNCA average as a MW reduction from installed capacity. May need to revise next year as a reduction from 1937 capability.

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

7/ Reserves are same percent of total load, including exports, as WhiteBook (varies monthly from 10.9% to 13.4%).

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

TABLE 2
2012-13 ASSURED OPERATING PLAN
DETERMINATION OF THERMAL DISPLACEMENT MARKET
(Energy in Average MW)

	Aug15	Aug31	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	Jun	Jul	Annual Average	CP Avg (42.5 mon)
1. STEP I THERMAL INSTALLATIONS																
a) From Table 1A, line 6(c)	10652	10651	10696	10666	10654	10607	10658	10695	9432	8984	8539	7261	9216	10535	9981.8	10085.9
2. DISPLACEABLE THERMAL RESOURCES																
a) Minimum Generation from % of Thermal	240	240	241	240	240	238	240	241	209	198	187	173	229	239	226.7	228.7
b) Net Displaceable Thermal Resources	**10412**	**10412**	**10455**	**10426**	**10414**	**10369**	**10419**	**10454**	**9222**	**8786**	**8352**	**7088**	**8986**	**10296**	**9755.1**	**9857.2**
3. SYSTEM SALES (i.e. Amount of Coordinated Thermal Installation Power Used Outside PNWA)																
a) Flows-Out (Table 1A, line 2(f))	1370	1427	2712	1360	903	846	885	925	978	971	841	1862	3936	2466	1598.1	1549.8
b) ...Exclude Canadian Entitlement Exported	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500.0	-500.0
c) ...Exclude Plant Sales	-175	-176	-183	-185	-189	-184	-181	-176	-211	-182	-174	-57	-195	-188	-175.0	-176.1
d) ...Exclude WB Flow-Through-Transfer	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75	-60.0	-58.8
e) ...Exclude WB Seasonal Exchange	-214	-214	-205	-26	-3	-3	-3	-3	-3	-3	-3	-2	-87	-200	-62.8	-61.5
f) ...Exclude Added Seasonal Exchange	0	-29	-1392	-356	0	0	0	0	0	0	0	-1041	-2838	-1205	-570.0	-523.9
g) ...Exclude Other Flow-Through-Transfer	-23	-23	-26	-23	-30	-30	-30	-31	-29	-26	-10	-7	-8	-24	-23.2	-23.9
h) ...Exclude Other Seasonal Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0.0
i) ...Total System Sales	382	410	332	226	136	84	127	171	191	185	80	180	233	273	207.0	205.6
j) Uniform Average Annual System Sales	207	207	207	207	207	207	207	207	207	207	207	207	207	207	207.0	207.0
4 THERMAL DISPLACEMENT MARKET	**10205**	**10205**	**10248**	**10219**	**10207**	**10162**	**10212**	**10247**	**9015**	**8579**	**8145**	**6881**	**8779**	**10089**	**9548.1**	**9650.2**

Notes:

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

3b Canadian Entitlement exports are assumed to be supported by hydro instead of thermal.

3c Plant sales include Longview Fibre and approximately 25 percent of Boardman; line 2(g), Table 1A.

3d Flow-through-transfers from the White Book

3e Seasonal Exchanges from the White Book

3f Added Seasonal Exchanges for AOP surplus

3g Other flow through transfers are remaining flows-out supported by remaining thermal imports in the same period.

3h Other Season Exchanges remaining exports supported by thermal imports greater than imports on an annual basis

3i Total System Sales are assumed to be supported by Coordinated PNWA Thermal Installations and are total exports excluding exchanges, plant sales, Flow-through-transfers, and the Canadian Entitlement. The sum of Lines 3(a) through 3(h).

3j 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(j).

TABLE 3
2012-13 ASSURED OPERATING PLAN
DETERMINATION OF LOADS FOR
STEP II AND STEP III STUDIES

	PACIFIC NORTHWEST AREA LOAD					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
August 1-15	22052	97.51	28405	77.64	10652	18414.0	7762.2	15811.5	5159.8	August 1-15
August 16-31	22027	97.40	28339	77.73	10651	18393.0	7741.9	15793.5	5142.4	August 16-31
September	20720	91.62	26540	78.07	10696	17301.2	6605.5	14856.0	4160.3	September
October	20879	92.33	28724	72.69	10666	17434.4	6768.2	14970.4	4304.1	October
November	23107	102.18	31913	72.41	10654	19294.4	8640.4	16567.5	5913.5	November
December	25171	111.30	34075	73.87	10607	21018.2	10410.8	18047.6	7440.3	December
January	25676	113.54	35047	73.26	10658	21440.2	10781.9	18410.1	7751.8	January
February	24658	109.04	33641	73.30	10695	20589.8	9895.2	17679.8	6985.2	February
March	22813	100.88	30702	74.30	9432	19049.3	9617.8	16357.0	6925.5	March
April 1-15	21567	95.37	28616	75.37	8984	18008.7	9025.2	15463.6	6480.0	April 1-15
April 16-30	21549	95.29	28580	75.40	8539	17993.9	9454.7	15450.8	6911.6	April 16-30
May	20888	92.36	27766	75.23	7261	17441.4	10180.9	14976.4	7715.9	May
June	21436	94.79	27959	76.67	9216	17899.2	8683.4	15369.5	6153.7	June
July	22513	99.55	29380	76.63	10535	18798.5	8263.7	16141.7	5606.9	July
Annual Avg. 7/	22614.8	100.00		74.96	9981.8	18883.7	8901.8	16214.8	6233.0	Annual Avg
SI CP Avg (42.5)	22713.8			**74.85**	10085.9					<==Au31-Feb
S2 CP Avg (20)	22798.9				10097.2	19037.4	8940.2			<==Sep-Ap30
S3 CP Avg.(5.5)	24039.8				10273.7			17236.6	6962.9	<==Nov-Ap15
						Input 5/=	**8940.20**	Input 6/=	**6962.88**	
August 1-31	22039.3	97.46	28404.9	77.68	10651.4	18403.1	7751.7	15802.2	5150.8	Aug. 1-31
April 1-30	21558.1	95.33	28616.4	75.38	8761.4	18001.3	9239.9	15457.2	6695.8	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 2012-13 operating year. The critical period (CP) averages are for the historic water years.

TABLE 4
(English & Metric Units)
2012-13 ASSURED OPERATING PLAN
SUMMARY OF POWER REGULATIONS

	BASIC DATA		STEP I				STEP II					STEP III				
	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE kaf	USABLE STORAGE hm^3	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE kaf	USABLE STORAGE hm^3	JANUARY 1945 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE kaf	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			7000	8634			7000	8634								
Arrow			7100	8758			7100	8758								
Duncan			1400	1727			1400	1727								
Subtotal			15500	19119			15500	19119								
b) BASE SYSTEM																
Hungry Horse	4	428	3072	3789	289	102	3008	3710	193	116	103	3008	3710	332	239	104
Kerr	3	160	1219	1504	176	124	1219	1504	175	112	130	1219	1504	174	153	123
Thompson Falls	6	85	0	0	85	56	0	0	85	53	59	0	0	85	66	57
Noxon Rapids	5	554	231	285	523	147	0	0	528	128	195	0	0	528	173	195
Cabinet Gorge	4	239	0	0	238	98	0	0	238	86	120	0	0	238	113	118
Albeni Falls	3	50	1155	1425	21	24	1155	1425	18	22	21	1155	1425	11	16	19
Box Canyon	4	74	0	0	71	46	0	0	70	45	48	0	0	69	57	47
Grand Coulee	24+3SS	6684	5185	6396	6360	2057	5072	6256	6364	1836	2396	5072	6256	5617	1226	2298
Chief Joseph	27	2535	0	0	2535	1066	0	0	2535	967	1307	0	0	2535	701	1233
Wells	10	840	0	0	840	420	0	0	840	388	490	0	0	840	287	441
Chelan	2	54	677	835	51	38	676	834	51	37	44	676	834	51	43	43
Rocky Reach	11	1267	0	0	1267	573	0	0	1267	529	693	0	0	1267	384	642
Rock Island	18	513	0	0	547	263	0	0	547	246	314	0	0	547	182	289
Wanapum	10	986	0	0	825	501	0	0	825	464	588	0	0	825	329	520
Priest Rapids	10	912	0	0	770	488	0	0	770	455	562	0	0	770	330	496
Brownlee	5	675	975	1203	675	243	974	1201	675	301	320	974	1201	675	263	320
Oxbow	4	220	0	0	220	101	0	0	220	126	130	0	0	220	116	130
Ice Harbor	6	693	0	0	693	215	0	0	693	231	303	0	0	693	163	303
McNary	14	1127	0	0	1127	626	0	0	1127	601	771	0	0	1127	442	716
John Day	16	2484	535	660	2484	942	0	0	2484	917	1255	0	0	2484	683	1215
The Dalles	22+2F	2074	0	0	2074	750	0	0	2074	731	994	0	0	2074	564	971
Bonneville	18+2F	1088	0	0	1047	566	0	0	1047	549	683	0	0	1047	432	640
Kootenay Lake	0	0	673	830	0	0	673	830	0	0	0	673	830	0	0	0
Coeur d'Alene Lake	0	0	223	275	0	0	223	275	0	0	0	223	275	0	0	0
Total Base System 1/		23742	29445	36320	22918	9445	28500	35154	22825	8940	11526	13000	16035	22207	6963	10921
c) ADDITIONAL STEP I PROJECTS																
Libby	5	600	4980	6143	540	196										
Boundary	6	1055	0	0	855	367										
Spokane River Plants 2/	24	173	104	128	158	94										
Hells Canyon	3	450	0	0	379	199										
Dworshak	3	450	2015	2485	445	157	NOT APPLICABLE TO STEPS II & III									
Lower Granite	6	932	0	0	930	171										
Little Goose	6	932	0	0	928	179										
Lower Monumental	6	932	0	0	923	171										
Pelton, Rereg., & RB	7	423	274	338	419	136										
Total added Step I		5947	7373	9094	5576	1671										
2. THERMAL INSTALLATIONS 3/					12878	10086			12878	10097	9982			12878	10274	9982
3. TRANSMISSION LOSSES, HYDRO MAINTENANCE & PEAK RESERVES 4/					-6603	-686			-4264	0	0			-3795	0	0
4. TOTAL RESOURCES 5/					34769	20516			31439	19037	21508			31289	17236	20903
5. STEP I, II, & III SYSTEM LOADS 6/					30684	20517			29265	19037	18884			25129	17237	16215
6. SURPLUS (4 - 5)					4084	0			2174	0	2624			6161	0	4688
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		13-41				13-42					13-13				

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, Upper Falls, and Post Falls.

3/ From Tables 1 and 3.

4/ Step I peak transmission losses, hydro maintenance and reserves are from Table 1b, lines 8a+b+c. Energy transmission losses and maintenance from Table 1a, lines 8a+8b. Steps II & III Peak Reserves & Maintenance are based on same percent as WB07, i.e. approximately 12% 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/ Total Resources is the sum of lines 1b+1c+2+3. For Step I, this does not include non-Step I coordinated hydro or hydro-independents.

6/ Step I energy load from Table 1A, line 5, and January peak load from Table 1B, line 5. 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 5

COMPUTATION OF CANADIAN ENTITLEMENT FOR 2012-13 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S.
(From Streamline calculation using 12-42 30yr study)
B. Optimum Power Generation in the U.S. Only
(From Streamline calculation using 12-12 30yr study)

Determination of Dependable Capacity Credited to Canadian Storage (MW)

	(A)	(B)
Step II - Critical Period Average Generation 1/	8940.2	8940.2
Step III - Critical Period Average Generation 2/	6962.9	6962.9
Gain Due to Canadian Storage	1977.3	1977.3
Average Critical Period Load Factor in percent 3/	74.85	74.85
Dependable Capacity Gain 4/	2641.7	2641.7
Canadian Share of Dependable Capacity 5/	1320.8	1320.8

Determination of Increase in Average Annual Usable Hydro Energy (aMW)

Step II (with Canadian Storage) 1/	(A)	(B)
Firm Energy 6/	8902.5	8902.5
Thermal Displacement Energy 7/	2484.0	2480.4
Remaining Usable Energy 8/	55.9	56.4
System Average Annual Usable Energy	11442.4	11439.3
Step III (without Canadian Storage) 2/		
Firm Energy 6/	6233.5	6233.5
Thermal Displacement Energy 7/	3874.9	3874.9
Remaining Usable Energy 8/	325.0	325.0
System Average Annual Usable Energy	10433.4	10433.4
Average Annual Usable Energy Gain 9/	1009.0	1005.9
Canadian Share of Average Annual Energy Gain 5/	504.5	502.9

1/ Step II values were obtained from streamline calculation from 12-42 and 12-12 studies.
2/ Step III values were obtained from streamline calculation 12-13 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 Feb.).
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

	2008-09	2009-10	2010-11	2011-12	2012-13
AVERAGE PNWA ENERGY LOAD					
Annual Load (MW)	24495.5	22268.2	22033.0	21710.9	22614.8
Annual/January Load (%)	87.3	87.5	88.1	87.9	88.1
Critical Period (CP) Load Factor (%)	75.7	73.9	75.9	76.1	74.9
Annual Firm Exports 1/	704.7	639.6	636.7	687.9	901.2
Annual Firm Surplus (MW) 2/	747.3	762.4	578.5	554.0	570.0
THERMAL INSTALLATIONS (MW) 3/					
January Peak Capability	12417	9756	11762	11455	12878
CP Energy	11228	8891	9418	9480	10086
CP Minimum Generation	245	196	212	211	229
Average Annual System Export Sales	259	144	333	232	207
Average Annual Displaceable Market	10643	8504	8779	8969	9548
HYDRO CAPACITY (MW)					
Total Installed	29689	29689	29689	29322	29689
Base System	23742	23742	23742	23427	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 4/					
Step I 30-yr. Average Streamflow, cfs	176702	175663	175395	175361	175361
Step I CP Average, cfs	114401	115061	114765	114734	114734
Step II CP Average, cfs	101525	101961	101628	101578	101578
Step III CP Average, cfs	57184	56558	56079	56027	56027
Step I 30-yr. Average Streamflow, m3/s	5003.64	4974.22	4966.63	4965.67	4965.67
Step I CP Average, m3/s	3239.47	3258.17	3249.79	3248.92	3248.92
Step II CP Average, m3/s	2874.87	2887.22	2877.79	2876.38	2876.38
Step III CP Average, m3/s	1619.27	1601.55	1587.99	1586.52	1586.52
CAPACITY BENEFITS (MW)					
Step II CP Generation	9018.7	9018.1	8998.2	8944.6	8940.2
Step III CP Generation	7132.2	7020.8	7000.1	6945.5	6962.9
Step II Gain over Step III	1886.5	1997.3	1998.1	1999.1	1977.3
CANADIAN ENTITLEMENT	1245.2	1352.3	1316.4	1314.0	1320.8
Change due to Mica Reoperation	0.0	0.0	0.0	0.0	0.0
ENERGY BENEFITS (aMW)					
Step II Annual Firm	8921.2	8907.7	8981.9	8904.7	8902.5
Step II Thermal Displacement	2558.9	2444.1	2414.7	2448.7	2484.0
Step II Remaining Usable Secondary	25.4	87.6	67.2	69.1	55.9
Step II System Average Annual Usable	11505.5	11439.4	11463.8	11422.5	11442.4
Step III Annual Firm	6243.5	6174.1	6324.3	6227.6	6233.5
Step III Thermal Displacement	4084.5	3707.8	3699.3	3776.2	3874.9
Step III Remaining Usable Secondary	247.7	423.2	368.7	366.8	325.0
Step III System Average Annual Average	10575.7	10305.1	10392.3	10370.6	10433.4
CANADIAN ENTITLEMENT	464.9	567.1	535.7	525.9	504.5
Change due to Mica Reoperation	1.9	3.9	2.0	2.0	1.6
STEP II PEAK CAPABILITY (MW)	33008	30530	30601	29985	31439
STEP II PEAK LOAD (MW)	31564	28996	28258	28338	29265
STEP III PEAK CAPABILITY (MW)	32882	30371	30571	29855	31289
STEP III PEAK LOAD (MW)	25758	23142	24155	24195	25129

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 added average annual surplus shaped in the following periods:

AOP Study	Amount Shaped (MW)
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.
2011-12	1231 Sep, 313 April 30, 938 May, 3165 June, and 1198 July.
2012-13	29 Aug 31, 1392 Sep, 356 Oct, 1041 May, 2838 June, and 1205 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 2007-08 and 2008-09 DDPBs with adjustments for the Grand Coulee pumping and return flows. 2000 level modified flows were used beginning with the 2009-10 DDPB with adjustments for the Grand Coulee pumping and return flows. The 2010-11, 2011-12, and 2012-13 DDPBs include updated adjustments for the Grand Coulee pumping but not for return flows.

CHART 1
2012-13 DDPB STUDIES
DURATION CURVES OF 30 YEARS MONTHLY HYDRO GENERATION
(aMW)