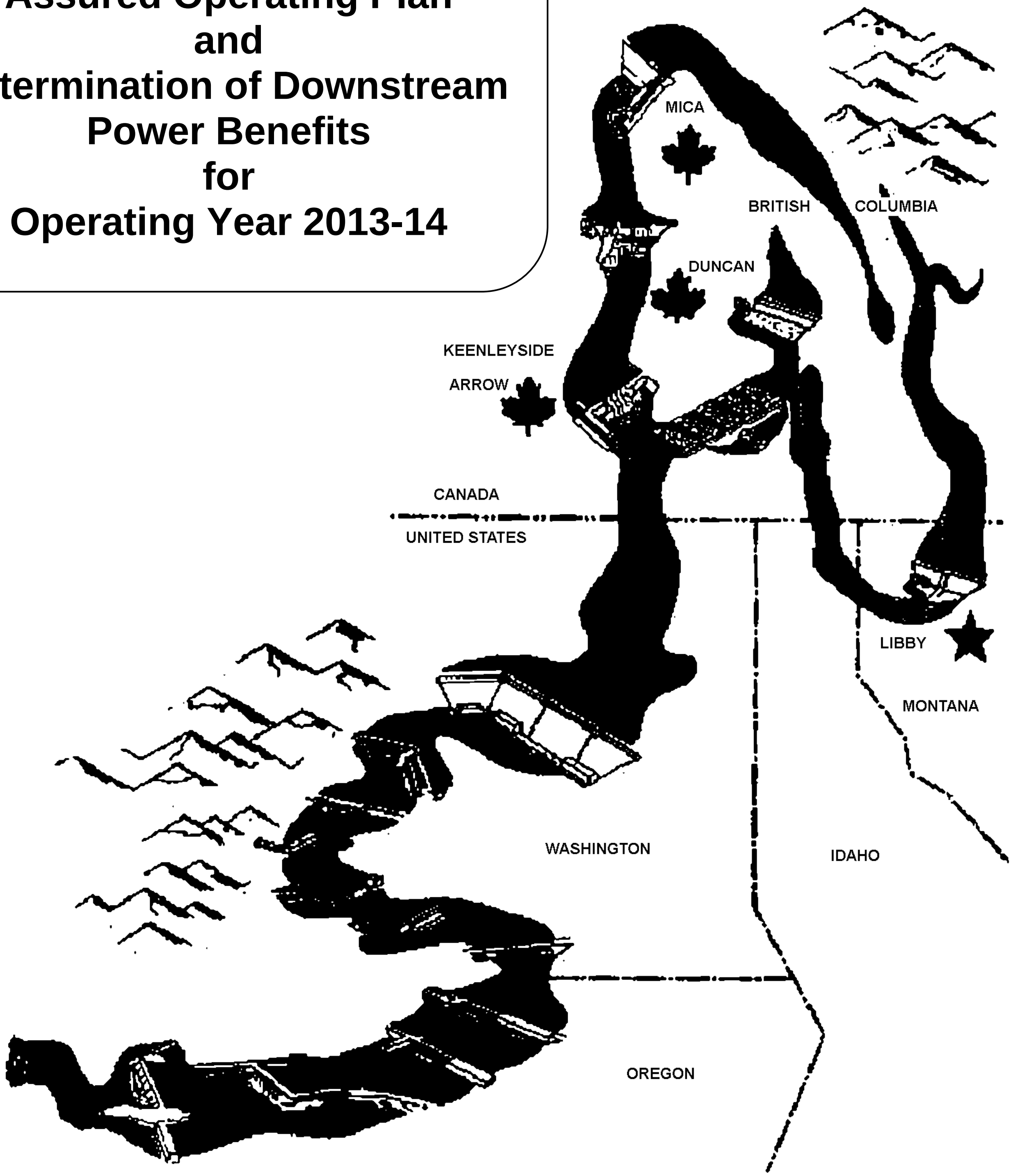
COLUMBIA RIVER TREATY
Assured Operating Plan
and
Determination of Downstream Power Benefits
for
Operating Year 2013-14



Columbia River Treaty Operating Committee

December 2008

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COLUMBIA RIVER TREATY ENTITY AGREEMENT ON THE ASSURED OPERATING PLAN AND DETERMINATION OF DOWNSTREAM POWER BENEFITS FOR THE 2013-14 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 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 2013-14" and "Columbia River Treaty Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2013-14," both dated December 2008, shall be the Assured Operating Plan and Determination of Downstream Power Benefits for the 2013-14 Operating Year.

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

Executed for the Canadian Entity this 11 day of February, 2009.

By: ______________________
Robert G. Elton
Chair

Executed for the United States Entity this 28th day of January, 2009.

By: ______________________
Stephen J. Wright
Chairman

By: ______________________
BG William E. Rapp
Member

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COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

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HYDROELECTRIC OPERATING PLAN
ASSURED OPERATING PLAN
FOR OPERATING YEAR 2013-14

December 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 created by the Treaty for the operation of the Treaty storage in Canada (Canadian Treaty Storage) during the sixth succeeding year. This AOP for operating year 2013-14 (AOP14) 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.

2. Development of the Assured Operating Plan

a) Procedures

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

- Except for the changes noted below, 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 October 2003 and signed 16 December 2003, including the update to Appendix 1, dated 18 November 2003 and the November 2004 additions of Appendix 6, Streamline Procedures, and Appendix 7, Table of

Median Stream flows, and the 25 September 2007 addition of Appendix 8 concerning Water Supply Forecasts.

Special terms used in this document, but not defined herein, have the meanings defined in the Treaty, Protocol, or the above Entity Agreements. 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 only the first two of the three streamline procedures defined in Appendix 6 of the POP, which are:

- “Forecasting Loads and Resources” for determining the thermal installations with a modification to allocate available uncommitted Pacific Northwest Area (PNWA) resources and available uncommitted imports from Canada and California, together with a seasonal exchange, to balance the forecasted PNWA firm energy deficit, as described in Subsection 7(b) of this document; and

- “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(b).

In addition, the Entities have agreed to:

- Allocate available uncommitted PNWA resources and available uncommitted imports from Canada and California, together with a seasonal exchange, to balance the White Book (WB) firm load/resource deficit, as was done in the AOP13 studies and is described in Subsection 7(b);

- Develop Steps II and III critical period and 30-year USA optimum hydroregulation studies and determine the downstream power benefits as described in Section 3.3 of POP, except that the effect of the reoperation of Canadian storage on the Step II study is agreed to be a 2.0 aMW increase in Energy Entitlement and no change in the Capacity Entitlement.

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:

- The Critical Rule Curves (CRCs), Upper Rule Curves (URCs), and the related rule curves and data for each project used to compute the individual project Operating Rule Curves (ORCs);

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

- 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.

b) 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 2013-14 operating year estimated loads and resources in the USA PNWA, 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 the same as the AOP12. With the same regulated hydro load, the AOP12 Step I System Regulation Studies can serve as the basis for the AOP14.

In determining the Canadian Entitlement, studies were developed for the Steps II and III critical period and 30-year hydroregulation studies for optimum generation in the USA alone. Since the AOP14 uses the Streamline Method to implement the AOP12 Joint Optimum operating criteria, the Entities agreed that the change in Canadian Entitlement due to Canadian storage operation for optimum generation in both Canada and the USA would be the same as in the DDPB12. The DDPB12 Joint Optimum shows a 2.0 aMW increase in the Canadian Entitlement for average annual usable energy and no change in the dependable capacity.

In accordance with Protocol VIII, the AOP14 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.

c) 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 AOP14, 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.

As part of the Streamline Method, and as described in Subsection 2(b), the USA and Joint Optimum studies are from the AOP12.

(2) Maximum Permitted Reduction in Downstream Power Benefits

As explained in Subsection 2(b), the downstream power benefits were determined using a Step II system regulation study reflecting Canadian Treaty Storage operation for optimum generation in the USA alone and an agreed upon change in Canadian Entitlement due to Canadian storage operation for optimum generation in both Canada and the USA based on the DDPB12. The DDPB12 joint optimum shows a 2.0 aMW increase in the Canadian Entitlement for average annual usable energy and no change in the dependable capacity compared to the operation for optimum generation in the USA alone. (See Table 5 from the DDPB12 and DDPB14, columns A and B.)

Annex A, paragraph 7, of the Treaty defines the limits to any reduction in the downstream power benefits in the USA resulting from a change in operation to achieve a joint optimum operation. Since there is no reduction in entitlement, the calculation of maximum permitted reduction in downstream power benefits is not necessary.

3. Rule Curves

The operation of Canadian Treaty Storage during the 2013-14 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 CRCs are higher than any of the lower numbered CRCs, and past practice was for the hydro regulation model to lower the storage amounts in the higher numbered CRCs 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, Assured Refill Curves (ARCs) and Variable Refill Curves (VRCs), 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 Curves

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 Curves

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 AOP14, as in the AOP12 and AOP13, 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 2013-14, the PDRs and VRCLLs will be based on the forecast of unregulated runoff at The Dalles.

c) Operating Rule Curve Lower Limits (ORCLLs)

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 VRCs 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 Curves (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 Curves

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 2013-14 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 AOP14 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 utilized in prior AOPs.

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. of the Columbia River Treaty, which states in part:

". . . 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 2013-14 DOP (DOP14) 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 DOP14. Failing agreement on updating the data and/or criteria, the DOP14 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 2013-14 Operating Year shall be guided by the DOP14.

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 2013-14."

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 2013 through 31 July 2014 period covered by this AOP, and includes transmission losses and scheduling guidelines for delivery of the Canadian Entitlement.

7. Summary of Changes Compared to the 2012-13 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 AOP14 are based on Bonneville Power Administration's (BPA) March 2008 Draft White Book (WB08)[5] expected load forecast. The Draft WB08 forecast for the 2013-14 regional firm load is 23,271 annual aMW, and is based on a 1.3% annual load growth from the 2013 to 2014 operating year. This forecast for the AOP14 is 192 aMW (0.8%) higher than the WB07 forecast used in the AOP13. 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 188 annual aMW (0.8%) from the AOP13 to AOP14.

The average critical period load factor decreased from 74.85% in AOP13 (WB07) to 74.60% in AOP14 (WB08). 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 AOP14, the estimate of the amount of Canadian Entitlement energy and uncommitted resources that would be assumed to serve load in the PNWA was based on a similar procedure as in the AOP13. 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 determines the WB08 firm energy deficit without uncommitted thermal resources, adds a seasonal exchange to minimize the firm deficits, and then 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 to eliminate deficits. The first step reduces or eliminates the monthly deficits using available uncommitted PNWA resources (without unreported CT capability) and available Canadian imports. For the AOP14, the Entities had agreed that 53% (268 annual aMW) of the available Canadian Entitlement (505 annual aMW) would be used as a Canadian import for serving PNWA load, with the uncommitted PNWA resources (without unreported CT capability) being allocated next to reduce or eliminate the monthly deficits. 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. Compared to AOP13, this is equivalent to a 3 annual aMW increase in Entitlement energy serving load in the U.S.
- The estimated Canadian Entitlement included in export loads was 505 average annual MW of energy and 1350 MW of capacity. The amount computed for the DDPB14 is 505.5 average annual MW of energy and 1335.5 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 AOP13, power flows-out (exports that are mostly to the southwest but also include the Entitlement) increased by 242 annual aMW,

and power flows-in (imports) increased by 219 annual aMW. These differences are primarily due to changes in WB imports/exports.

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 AOP14, these resources have increased by 176 annual aMW over the AOP13. This is primarily due to the addition of 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. In this AOP, an average of the two year maintenance cycle at CGS was used, which resulted in 76 aMW increase in annual average generation from AOP13 to AOP14. The total thermal installations increased by 49 annual aMW from AOP13 to AOP14 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 AOP14 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 AOP14 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 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.

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 March 2008 Draft of the "2008 Pacific Northwest Loads & Resources Study, Operating Years 2009 through 2018", dated June 2008, and expected to be published early in 2009.

TABLE 1
(English Units)
MICA PROJECT OPERATING CRITERIA
2013-14 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
2013-14 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 2013-14 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
2013-14 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 DOP14 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		The Dalles Volume Runoff		Maximum Storage Limit	
		(Maf)	(km^3)	(Maf)	(km^3)	(ksfd)	(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 2013-14 ASSURED OPERATING PLAN
STUDY RESULTS

Study 14-41 provides Optimum Generation in Canada and in the United States.
Study 14-11 provides Optimum Generation in the United States only.

	Study No. 14-41	Study No. 14-11	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)
2013 - 14 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 2014 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
2013 - 14 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
2013 - 14 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
2013 - 14 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)
2013 - 14 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)
2013 - 14 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)
2013 - 14 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)
2013 - 14 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)
2013 - 14 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 through 2013-14 /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 and 2013-14 utilize the same system regulation studies as the 2011-12 AOP/DDPB.

TABLE 1M
(Metric Units)
MICA PROJECT OPERATING CRITERIA
2013-14 ASSURED OPERATING PLAN

Month	End of Previous Month **Arrow** Storage Content (hm3)	Target Operation: Month Average Outflow (m^3/s)	Target Operation: End-of-Month Treaty Storage Content 1/ (hm3)	Target Operation Limits: Minimum Treaty Storage Content 2/ (hm^3)	Target Operation Limits: Maximum Outflow 1/ (m^3/s)	Target Operation Limits: 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
2013-14 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 2013-14 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)
2013 - 14 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 2014 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
2013 - 14 ASSURED OPERATING PLAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ASSURED REFILL CURVE (hm³)														
	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 (hm³)														
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 (hm³)							1781.4	1276.9	1113.9	1028.3	1028.3	982.3	971.5	N/A
POWER DISCHARGE REQUIREMENTS (m³/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 km³		84.95	84.95	84.95	84.95	84.95	84.95	906.14	1076.04
(BY VOLUME RUNOFF AT THE DALLES)					117.18 km³		84.95	84.95	84.95	84.95	84.95	84.95	509.70	914.63
					135.69 km³		84.95	84.95	84.95	84.95	84.95	84.95	509.70	914.63
OPERATING RULE CURVE LOWER LIMITS (hm³)							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
2013 - 14 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
2013 - 14 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)
2013 - 14 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)
2013 - 14 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)
2013 - 14 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)
2013 - 14 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)
2013 - 14 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 through 2013-14 /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 and 2013-14 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 2893.0 ft	1503.9 hm^3 881.79 m	Jun - Sep	MPC 2-1-92, PNCA submittal similar operation, Jun-Aug 15, in AOP80.
		426.3 ksfd 2890.0 ft	1043 hm^3 880.9 m	May	
		0.0 ksfd 2883.0 ft	0 hm^3 878.74 m	Empty Apr 15	FERC, AOP80.
	Maximum Content	58.6 ksfd 2884.0 ft	143.37 hm^3 879.04 m	March (Included to help meet the Apr 15 FERC requirement.)	In place in AOP80, AOP84.
	Other	0.0 ksfd 2883.0 ft	0 hm^3 878.74 m	Conditions permitted, should be on or about, empty Mar and Apr 15.	FERC, AOP80.
Thompson Falls (1490)				None Noted	

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

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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 268.0 ft	659.8 hm^3 81.69 m	June - Aug 15	In place AOP80
		242.5 ksfd 267.0 ft	593.3 hm^3 81.38 m	Aug 31 - Sep	
		153.7 ksfd 263.6 ft	376.0 hm^3 80.35 m	Oct - Mar	
		114.9 ksfd 262.0 ft	281.1 hm^3 79.86 m	Apr - May	
	Steps II & III:	190.0 ksfd 265.0 ft	464.8 hm^3 80.77 m	Use JDA as run-of-river plant.	
The Dalles (365)	Fish Spill/Bypass			None	
	Other Spill	1300 cfs	36.8 m^3/s	All periods	
	Incremental Spill			None	
	Minimum Flow	50000 cfs 12500 cfs	1415.8 m^3/s 354.0 m^3/s	Mar - Nov Dec - Feb	
Bonneville (320)	Fish Spill/Bypass			None	
	Other Spill	8040 cfs	227.7 m^3/s	All periods	
	Incremental Spill			None	
Kootenay Lake (Corra Linn (1665))	Minimum Flow	5000 cfs	141.6 m^3/s	All periods	BCHydro agreements 1969.
	Other			Operate to IJC orders.	CRTOC agreement on procedures to implement 1938 IJC order.
Chelan (1210)	Minimum Flow	50 cfs	1.4 m^3/s	All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	308.5 ksfd	126.1 hm^3	Jul - Sep (except as needed to empty at end of critical period).	In place in AOP79, AOP80, AOP84
		1098.0 ft	334.7 m		
Couer d'Alene L (1341)	Minimum Flow	50 cfs	1.4 m^3/s	All periods	In place in AOP79.
	Minimum Content	112.5 ksfd 2128.0 ft	275.2 hm^3 648.6 m	May - Aug Flood control may override these minimum contents.	2-1-00 PNCA submittal
Post Falls (1340)	Minimum Flow	50 cfs	1.4 m^3/s	All periods	In place in AOP79, AOP80, AOP84.
<u>Other Major Step I Projects</u>					
Libby (1760)	Minimum Flow	4000 cfs	113.3 m^3/s	All periods	
	Other Spill	200 cfs	5.7 m^3/s	All periods	

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

Appendix A
Project Operating Procedures for the 2013-14
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 3180.0 ft	59.9 hm^3 969.26 m	Oct - May	3-6-01 PNCA submittal
		31.1 ksfd 3190.0 ft	76.1 hm^3 972.31 m	Jun - Aug 31	
		27.8 ksfd 3185.0 ft	68.0 hm^3 970.79 m	Sep [(24.5*15+31.1*15)/30]	
Long Lake (1305)	Minimum Content	50.1 ksfd 1535.0 ft	122.6 hm^3 467.87 m	Apr - Nov	2-5-02 PNCA submittal
		19.7 ksfd 1522.0 ft	48.2 hm^3 463.9 m	Dec - Mar	
	Draft Rate Limit	1.0 ft/day	0.30 m/day		2-1-03 PNCA submittal
Priest Lake (1470)	Maximum Content	0.0 ksfd 0.0 ft	0.0 hm^3 0.00 m	Oct	2-1-03 PNCA submittal
	Max/Min Content	35.5 ksfd 3.0 ft	86.9 hm^3 0.91 m	Maintain at or near after runoff through Sep.	
Ross (2070)	Minimum Content/			Dependent on Skagit Fisheries.	2-1-06 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 2013-14

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DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB) FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2013-14

December 2008

1. Introduction

The "Treaty between Canada and The United States of America relating to 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 the Treaty storage in Canada (Canadian Treaty Storage) to be determined in advance by the two Entities created by the Treaty. The purpose of this document is to describe the results of the Determination of Downstream Power Benefits for operating year 2013-14 (DDPB14).

2. Procedures

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

- Except for the changes noted below, 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 October 2003 and signed 16 December 2003, 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, and the 25 September 2007 addition of Appendix 8 concerning Water Supply Forecasts.

Special terms used in this document, but not defined herein, have the meanings defined in the Treaty, Protocol, or the above Entity Agreements. 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 only the first two of the three streamline methods defined in Appendix 6 of the POP, which are:

- "Forecasting Loads and Resources," for determining the thermal installations described in Subsection 7(d) of the AOP14, and

- "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) of the AOP14.

In addition, the Entities have agreed to the following modifications to the DDPB study procedures:

- Allocate available uncommitted Pacific Northwest Area (PNWA) resources and available uncommitted imports from Canada and California, together with a seasonal exchange, to balance the White Book (WB) deficit, as was done in the DDPB13 studies and is described in Subsection 7(b) of the AOP14; and

- Modify the DDPB14 Table 2 calculation of Thermal Displacement Market, as was done in the DDPB13, 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 FTTs or SEs.

- Develop Steps II and III critical period and 30-year USA optimum hydroregulation studies and determine the downstream power benefits as described in Section 3.3 of POP, except that the effect of the reoperation of Canadian storage on the Step II study is agreed to be a 2.0 aMW increase in Energy Entitlement and no change in the Capacity Entitlement, as explained in Section 3.

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 4 below, the calculations were not needed for the 2013-14 operating year.

3. 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 downstream power benefits, was determined to be (see Table 5 Joint Optimum):

Dependable Capacity	= 1335.5 megawatts (MW)
Average Annual Usable Energy	= 505.5 average annual MW

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

In determining the Canadian Entitlement, studies were developed for the Steps II and III critical period and 30-year hydroregulation studies for optimum generation in the USA alone. Since the AOP14 uses the Streamline Method to implement the AOP12 Joint Optimum operating criteria, the Entities agreed that the change in Canadian Entitlement due to Canadian storage operation for optimum generation in both Canada and the USA would be the same as in the DDPB12. The DDPB12 Joint Optimum shows a 2.0 aMW increase in the Canadian Entitlement for average annual usable energy and no change in the dependable capacity.

4. Computation of Maximum Allowable Reduction in Downstream Power Benefits

Treaty Annex A, paragraph 7, states in part 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."*

As explained in Section 3 above, the Entities have agreed that optimum power generation in Canada and the USA would result in a 2.0 average megawatt (aMW) increase in the Energy Entitlement and no change to the Capacity Entitlement (See Table 5), compared to the DDPB14 Step II studies based on optimum power generation only in the USA. Given that there is no reduction in the downstream power benefits in the 2013-14 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.

5. Delivery of the Canadian Entitlement

See Section 6 of the AOP14.

6. Summary of Information Used for Canadian Entitlement Computations

The following tables and chart summarize the study results:

Table 1A Determination of Step I Firm Energy Hydro Loads
and
Table 1B Determination of Step I Firm Peak Hydro Loads

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 Section 2 of this DDPB14 and described in Subsection 7(b) of the AOP14. 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 AOP14, with a regulated hydro load very close to the same as in the AOP12 and AOP13. 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 PNWA and modified as noted in Section 2 of this DDPB14.

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) Draft 2008 White Book (WB08) load forecast as described in Subsection 7(a) of the AOP14. 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 Steps I, II, and III Power Regulations

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 full critical period and 30-year USA Optimum regulations studies for Steps II and III for AOP14.

Table 5 Computation of Canadian Entitlement

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 USA Optimum are shown under Column B. These elements are derived from (1) Steps II and III critical period studies based on loads determined in Table 3, (2) the Thermal Displacement Market from Table 2, and (3) the full Steps II and III 30-year USA Optimum Hydroregulation Studies. As explained in Section 3, the Joint Optimum studies were not conducted, and hence, the data under Column A is not available. 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 4).

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 USA Optimum 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.

7. Summary of Changes Compared to the 2012-13 DDPB and Notable Assumptions

Data from recent DDPBs are summarized in Table 6. The following is an explanation of changes and notable assumptions that impact computation of the entitlement compared to the 2012-13 DDPB (DDPB13) studies.

a) Steps II and III Firm Loads

The Steps II and III hydro firm loads shown on Table 3 are noticeably different from the DDPB13. Loads are substantially higher in March and May and substantially lower in April and June, as shown in the table below. This is mainly due to the change in Columbia Generating Station (CGS) and other thermal maintenance schedules, which are explained in Subsection 7(b).

Differences between Ddpb14 and Ddpb13 Table 3 Hydro Loads

	Aug1	*Aug2*	*Sept*	*Oct*	*Nov*	*Dec*	*Jan*	*Feb*	*Mar*	*15-Apr*	*30-Apr*	*May*	*June*	*July*	*Avg.*	*CPavg*
Ddpb14 S2	7817	7815	6666	6838	8710	10399	10822	9980	10009	8346	8587	10379	8379	8299	8897	8935
Ddpb13 S2	7762	7742	6605	6768	8640	10411	10782	9895	9618	9025	9455	10181	8683	8264	8902	8940
Difference	55	73	60	70	69	-12	40	85	392	-680	-868	198	-305	35	-5	-5
Ddpb14 S3	5160	5158	4169	4321	5918	7362	7723	7006	7255	5745	5983	7859	5790	5582	6168	6942
Ddpb13 S3	5160	5142	4160	4304	5914	7440	7752	6985	6926	6480	6912	7716	6154	5607	6233	6963
Difference	0	16	9	17	5	-78	-29	21	329	-735	-928	143	-363	-25	-65	-21

The average critical period load factor decreased slightly from 74.85% in AOP13 (WB07) to 74.60% in AOP14 (Draft WB08).

b) Thermal Installations

The total Thermal Installation energy capability shown in Table 3 increased by only 49 annual aMW compared to the DDPB13. This is due mainly to the combined effect of a 188 aMW increase in the PNWA firm load, a 23 aMW increase in the net export, a 176 aMW increase in the Step I renewable resources (mostly wind), and changes in the thermal maintenance schedules.

Beginning with AOP06, CGS changed from an annual maintenance cycle to a 24 month cycle. This created a circumstance where this maintenance was included only in alternate years of the AOP with a resulting effect of swings in energy entitlement. It was agreed for AOP14, after four AOPs with CGS maintenance in place and four AOPs without CGS maintenance, to return to an annual maintenance configuration (50% each year), thereby eliminating the year to year energy entitlement variability and reducing the effect on Step 1 seasonal exchanges.

In addition, the thermal maintenance schedules for other large projects (mostly coal but also combustion turbines and co-generation) changed resulting in a decrease in March and May thermal generation and a large increase in April.

The Thermal Displacement Market (TDM) increased by 30 annual aMW, due to a combination of the changes in Thermal Installations and System Sales. Both the Thermal Installation and TDM changes are shown in the following table.

DDPB14 minus DDPB13 Table 2 Thermal Installations and Thermal Displacement Market

	Aug1	*Aug2*	*Sept*	*Oct*	*Nov*	*Dec*	*Jan*	*Feb*	*Mar*	*15-Apr*	*30-Apr*	*May*	*June*	*July*	*Avg.*	*CPavg*
Ddpb14 T.I.	10613	10612	10654	10618	10654	10663	10676	10650	9099	9695	9473	7102	9575	10550	10031	10125
Ddpb13 T.I.	10652	10651	10696	10666	10654	10607	10658	10695	9432	8984	8539	7261	9216	10535	9982	10086
Difference	-39	-39	-42	-49	0	56	18	-44	-332	711	934	-158	360	15	49	40
TDM 14	10147	10147	10188	10152	10188	10196	10209	10184	8671	9252	9036	6715	9123	10085	9578	
TDM 13	10205	10205	10248	10219	10207	10162	10212	10247	9015	8579	8145	6881	8779	10089	9548	
Difference	-58	-58	-61	-67	-20	35	-2	-63	-344	673	891	-166	343	-4	30	

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 AOP14), 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

The critical rule curves were defined by the critical period studies, and the refill curves were calculated with the new CRCs and refill criteria (PDR, VRCLL, ECCLL) from the DDPB12 after verifying the refill test was passed. Overall assumptions are described in Subsection 7(f) of the AOP14.

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 AOP14 hydro project operating procedures, constraints, and plant data are retained from the AOP12. These assumptions are described in Subsection 7(g) of the AOP14.

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

Step II and Step III critical period regulation studies for the 2013-14 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 both average critical period generation (5.5 aMW) and average annual firm energy (4.6 aMW), and the Step III critical period showed a decrease in both average critical period generation (20.6 aMW) and average annual firm energy (64.4 aMW), both due mainly to changes in the hydro load shape affected by the changes to thermal maintenance. These changes in critical period generation and firm energy have the effect of slightly increasing the Canadian Entitlement.

For the 30-year System Regulation Studies, because of the changes to the Steps II and III hydro load shape (primarily due to changes in CGS and other thermal maintenance), the Entities agreed to not use the Streamline Method that uses the 2011-12 Steps II (-42 and -12) and III (-13) 30-year System Regulation Studies to estimate Steps II and III 30-year average annual usable hydro energy for this DDPB. Instead, traditional Steps II (-12) and III (-13) 30-year System Regulations Studies were performed for the DDPB14.

g) Downstream Power Benefits

The Canadian Capacity Entitlement increased from 1320.8 MW in the DDPB13 to 1335.5 MW in the DDPB14, an increase of 14.6 MW. This change is mainly due to hydro load shape changes resulting from the changes to thermal maintenance.

The Canadian Energy Entitlement increased slightly from 504.5 annual aMW in the DDPB13 to 505.5 annual aMW in the DDPB14, an increase of 1.0 annual aMW. This increase in Entitlement is mainly due to the change in thermal maintenance schedules.

End Notes:

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

2 The Step II DDPB14-12 and the Step III DDPB14-13 30-year system regulation studies, both dated 7 August 2008 and prepared by BPA, were used to determine the critical period and 30-year USA Optimum system generation.

TABLE 1A
DETERMINATION OF STEP I FIRM ENERGY HYDRO LOADS
FOR 2013-14 ASSURED OPERATING PLAN
(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/	22681	22690	21315	21470	23775	25861	26330	25294	23453	22161	22152	21529	22164	23297	23271	23368
b) Exclude 99% of UPL's Idaho load 3/	-485	-485	-451	-450	-450	-483	-453	-467	-436	-413	-413	-461	-534	-590	-473	-471
c) Adjustment to Coulee pumping 4/	6	-7	1	9	4	-5	22	27	4	-15	17	-7	-1	0	4	5
d) …Total PNWA Firm Loads	**22202**	**22199**	**20865**	**21029**	**23328**	**25374**	**25899**	**24854**	**23021**	**21733**	**21757**	**21060**	**21629**	**22708**	**22803**	**22902**
e) Annual Load Shape in Percent	97.4	97.4	91.5	92.2	102.3	111.3	113.6	109.0	101.0	95.3	95.4	92.4	94.9	99.6	100.0	100.4
2. Flows-Out of firm power from PNWA																
a) White Book Exports 5/	1115	1115	1065	850	802	841	837	832	866	866	774	691	916	1069	892	892
b) Remove WB Canadian Entitlement	-495	-495	-495	-495	-495	-495	-495	-495	-495	-495	-495	-495	-495	-495	-495	-495
c) Add est. Can. Entitlement Export 6/	505	505	505	505	505	505	505	505	505	505	505	505	505	505	505	505
d) Added SeEx for WB surplus 7/	0	0	0	0	0	0	0	0	0	0	0	0	3937	1212	426	361
e) Added SeEx for WB hydro shape 7/	0	1243	1665	243	0	0	0	0	0	0	1633	924	0	24	360	364
f) Import Thermal used out of region 8/	255	284	257	175	123	29	71	114	117	150	121	123	196	211	152	150
g) …Subtotal for Table 2	1380	2652	2997	1278	935	880	918	956	993	1026	2537	1749	5059	2526	1840	1778
h) Remove Plant Sales	-175	-176	-183	-185	-189	-184	-181	-176	-211	-182	-174	-57	-195	-188	-175	-176
i) Remove Flow-through-transfer	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75	-60	-59
j) …Total	**1130**	**2401**	**2739**	**1048**	**701**	**651**	**693**	**735**	**737**	**769**	**2289**	**1617**	**4788**	**2263**	**1605**	**1543**
3. Flows-In of firm power to PNWA, except from coordinated thermal installations																
a) White Book Imports 9/	-725	-696	-690	-743	-1005	-1184	-1065	-1018	-813	-750	-744	-701	-816	-881	-864	-874
b) Remove UP&L imports for 1(b)	485	485	451	450	450	483	453	467	436	413	413	461	534	590	473	471
c) Remove Thermal Installations 10/	125	96	124	205	259	352	311	267	203	194	214	131	163	168	208	213
d) Add Can. Import for WB deficits 11/	-268	-268	-268	-268	-268	-268	-268	-268	-268	-268	-268	-268	-268	-268	-268	-268
e) Added SeEx for WB deficit 7/	0	-1260	-330	0	0	0	-1237	-1917	-460	-32	-1257	0	0	0	-426	-457
f) Added SeEx for WB hydro shape 7/	-89	0	0	0	-158	-450	-346	-4	-1924	-1131	0	0	-793	0	-360	-327
g) Remove Flow-Through-Xfers	75	75	75	45	45	45	45	45	45	75	75	75	75	75	60	59
h) …Total	**-397**	**-1568**	**-638**	**-310**	**-677**	**-1021**	**-2107**	**-2427**	**-2780**	**-1498**	**-1568**	**-301**	**-1105**	**-316**	**-1177**	**-1183**
4. PNWA Non-Step I Hydro and Non-Thermal Resources																
a) Hydro Independents (1929 water)	-1016	-1010	-994	-1044	-1129	-1069	-1022	-856	-971	-1146	-1162	-1429	-1372	-1127	-1100	-975
b) Non-Step I Coordinated Hydro (1929)	-509	-456	-561	-944	-916	-962	-956	-490	-731	-767	-763	-742	-1316	-638	-793	-820
c) WB08 NUG Renewables	-125	-125	-125	-132	-150	-128	-147	-130	-161	-139	-139	-140	-139	-125	-137	-136
d) WB08 Regional Hydro NUGs	-310	-309	-232	-155	-114	-104	-94	-99	-133	-260	-269	-391	-422	-405	-228	-215
e) WB08 Renewables	-592	-592	-558	-531	-531	-460	-421	-429	-790	-621	-621	-689	-699	-673	-584	-571
f) …Total (1929)	**-2553**	**-2492**	**-2469**	**-2807**	**-2840**	**-2723**	**-2640**	**-2004**	**-2786**	**-2934**	**-2954**	**-3391**	**-3949**	**-2967**	**-2841**	**-2717**
5. Step I System Load (1929) 12/	**20382**	**20540**	**20498**	**18960**	**20512**	**22280**	**21845**	**21158**	**18192**	**18070**	**19524**	**18985**	**21363**	**21687**	**20390**	**20544**
6. Coordinated Thermal Installations 13/																
a) Columbia Generation Station (WNP2)	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	681	515	980	954	965
b) Generic Thermal Installations	9583	9582	9624	9588	9624	9633	9646	9620	8069	8665	8443	6421	9060	9570	9077	9160
c) ...Total	**10613**	**10612**	**10654**	**10618**	**10654**	**10663**	**10676**	**10650**	**9099**	**9695**	**9473**	**7102**	**9575**	**10550**	**10031**	**10125**
7. Step I Hydro Resources (1929) 14/	**10454**	**10643**	**10515**	**8971**	**10536**	**12347**	**11915**	**11226**	**9765**	**9014**	**10733**	**12539**	**12544**	**11887**	**11057**	**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/	-655	-690	-662	-620	-674	-730	-746	-718	-667	-632	-675	-636	-741	-701	-685	-686
9. Total Step I System Resources (1929)	**20382**	**20540**	**20498**	**18960**	**20512**	**22280**	**21845**	**21158**	**18192**	**18070**	**19524**	**18985**	**21363**	**21687**	**20390**	**20544**
10. Coordinated Hydro Load (1929) 16/	**10963**	**11099**	**11076**	**9915**	**11452**	**13309**	**12871**	**11716**	**10496**	**9781**	**11496**	**13281**	**13860**	**12525**	**11850**	**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/ Draft June 2008 BPA Whitebook (WB08) total regional firm load estimate including Coulee pumping and Utah P&L load in Idaho. Final WB08 was 17 average annual MW higher.

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 2008 PNCA data submittal to be consistent with the pumping flows in the Base Flows.

5/ WB08 exports include Firm Seasonal Exchanges, Flow-Through Transfers, Plant Sales, and an estimate of the Canadian Entitlement.

6/ Assumes 100% of Canadian Entitlement exported to Canada.

7/ Added Seasonal Exchanges that reshape WB08 surplus to minimize deficit and account for WB vs AOP hydro generation shape differences.

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 505 aMW of Energy Entitlement sold back to U.S.

12/ Line 1(d) + line 2(j) + line 3(i) + line 4(f), based on 1929 hydro independent capability

13/ Coordinated 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 2.73% 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
DETERMINATION OF STEP I FIRM PEAK HYDRO LOADS
FOR 2013-14 ASSURED OPERATING PLAN
(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	29826	29818	27968	29956	33146	35626	36296	34951	31989	29694	29705	28955	29231	30590
b) Exclude 99% of UPL's Idaho load	-527	-527	-485	-485	-491	-513	-485	-497	-463	-439	-439	-511	-612	-647
c) Account for Federal Peak Diversity 1/	-527	-568	-605	-432	-384	-625	-393	-406	-461	-580	-601	-607	-556	-449
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	**28781**	**28713**	**26879**	**29039**	**32271**	**34488**	**35418**	**34047**	**31065**	**28914**	**28877**	**28057**	**28317**	**29730**
f) Monthly Load Factors in Percent	77.14	77.31	77.63	72.42	72.29	73.57	73.12	73.00	74.11	75.16	75.34	75.06	76.38	76.38
2. Flows-Out of firm power from PNWA														
a) White Book Exports	2216	2217	2222	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 est. Can. Entitle. Exported	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350
d) Added SeEx for WB surplus	0	0	0	0	0	0	0	0	0	0	0	0	3937	1212
e) Added SeEx for WB hydro shape	0	1243	1665	243	0	0	0	0	0	0	1633	924	0	24
f) Import Thermal used out of region	272	308	281	211	116	0	51	95	123	175	155	122	174	237
g) ...Subtotal for Table 2	*2488*	*3768*	*4168*	*2302*	*1844*	*1724*	*1770*	*1809*	*1872*	*1924*	*3537*	*2772*	*6345*	*3701*
h) Remove Plant Sales	-185	-185	-192	-194	-198	-193	-190	-185	-220	-191	-191	-57	-205	-197
i) Remove Flow-through-transfer	-75	-75	-75	-45	-45	-45	-45	-45	-45	-75	-75	-75	-75	-75
j) ...Total	**2229**	**3508**	**3900**	**2063**	**1600**	**1485**	**1535**	**1579**	**1607**	**1657**	**3270**	**2640**	**6066**	**3429**
3. Flows-In of firm power to PNWA, except from coordinated thermal installations														
a) White Book Imports	-941	-905	-890	-932	-1315	-1497	-1446	-1449	-1043	-920	-935	-935	-1100	-1096
b) Remove UP&L imports for 1(b)	533	533	490	490	496	519	489	502	468	444	444	516	618	653
c) Remove Thermal Installations	187	151	179	250	347	463	412	368	273	242	257	197	260	222
d) Add Can. Import for WB deficits	-716	-716	-716	-716	-716	-716	-716	-716	-716	-716	-716	-716	-716	-716
e) Added SeEx for WB deficit	0	-1260	-330	0	0	0	-1237	-1917	-460	-32	-1257	0	0	0
f) Added SeEx for WB hydro shape	-89	0	0	0	-158	-450	-346	-4	-1924	-1131	0	0	-793	0
g) Remove Flow-Through-Xfers	75	75	75	45	45	45	45	45	45	75	75	75	75	75
h) ...Total	**-951**	**-2122**	**-1192**	**-863**	**-1301**	**-1635**	**-2798**	**-3170**	**-3356**	**-2037**	**-2132**	**-862**	**-1655**	**-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) WB08 NUG Renewables	-92	-92	-93	-93	-93	-93	-93	-93	-92	-93	-93	-92	-93	-92
d) WB08 Regional Hydro NUGs	-359	-357	-288	-206	-147	-134	-127	-137	-173	-287	-296	-420	-435	-428
e) WB08 Renewables	-19	-19	-19	-19	-19	-19	-19	-19	-19	-19	-19	-19	-19	-19
f) ...Total (1937)	**-4763**	**-4663**	**-4684**	**-4457**	**-4219**	**-4123**	**-3285**	**-3233**	**-4067**	**-4278**	**-4343**	**-4620**	**-4795**	**-4877**
5. Step I System Load (1937) 3/	**25296**	**25436**	**24904**	**25783**	**28351**	**30215**	**30871**	**29224**	**25249**	**24256**	**25673**	**25215**	**27933**	**27420**
6. Coordinated Thermal Installations														
a) Columbia Generating Station	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150
b) Generic Thermal Installations	11590	11590	11613	11649	11675	11686	11689	11680	9986	10508	10391	8051	10969	11586
c) ...Total	**12740**	**12740**	**12763**	**12799**	**12825**	**12836**	**12839**	**12830**	**11136**	**11658**	**11541**	**9201**	**12119**	**12736**
7. Step I Hydro Resc. needed (1937) 4/	**21207**	**20957**	**20165**	**21140**	**23513**	**24536**	**24734**	**23726**	**21553**	**20069**	**21442**	**22832**	**23476**	**23609**
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/	-991	-1034	-986	-986	-1062	-1129	-1156	-1121	-1055	-965	-1033	-987	-952	-1027
c) Reserves (approx 11%) 7/	-3065	-3195	-3252	-3962	-3991	-3991	-3986	-3926	-3759	-3755	-3794	-3472	-4509	-4179
9. Required Step I Resources (1937)	**25296**	**25436**	**24904**	**25783**	**28351**	**30215**	**30871**	**29224**	**25249**	**24256**	**25673**	**25215**	**27933**	**27420**
10. Coordinated Hydro Load (1937) 8/	23715	23387	22694	23604	25878	26828	26235	25056	23577	22108	23530	25004	25791	26107

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 + 2j + 3h + 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 WB08, 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 3.3% 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
DETERMINATION OF THERMAL DISPLACEMENT MARKET FOR 2013-14 AOP/DDPB STEPS II AND III STUDIES
(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)	10613	10612	10654	10618	10654	10663	10676	10650	9099	9695	9473	7102	9575	10550	10030.7	10125.5
2. DISPLACEABLE THERMAL RESOURCES																
a) Minimum Generation from % of Thermal	239	239	240	239	240	240	240	240	201	216	210	160	226	238	226.0	228.1
b) Net Displaceable Thermal Resources	**10374**	**10374**	**10415**	**10379**	**10415**	**10423**	**10436**	**10411**	**8898**	**9479**	**9263**	**6942**	**9350**	**10312**	**9804.7**	**9897.4**
3. SYSTEM SALES (i.e. Amount of Coordinated Thermal Installation Power Used Outside PNWA)																
a) Flows-Out (Table 1A, line 2(g))	1380	2652	2997	1278	935	880	918	956	993	1026	2537	1749	5059	2526	1840.3	1777.8
b) ...Exclude Canadian Entitlement Exported	-505	-505	-505	-505	-505	-505	-505	-505	-505	-505	-505	-505	-505	-505.0	-505.0	-505.0
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	-219	-218	-209	-26	-3	-3	-3	-3	-3	-3	-3	-2	-87	-205	-63.9	-62.6
f) ...Exclude added SeEx for WB surplus	0	0	0	0	0	0	0	0	0	0	0	0	-3937	-1212	-426.5	-361.1
g) ...Exclude added SeEx for WB hyd shape	0	-1243	-1665	-243	0	0	0	0	0	0	-1633	-924	0	-24	-359.6	-364.4
h) ...Exclude Other Flow-Through-Transfer	-23	-23	-26	-23	-30	-30	-30	-31	-29	-26	-10	-7	-8	-24	-23.3	-24.0
i) ...Exclude Other Seasonal Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0.0
j) ...Total System Sales	383	412	334	252	164	113	155	197	201	235	138	178	252	294	227.0	225.8
k) Uniform Average Annual System Sales	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227.0	227.0
4 THERMAL DISPLACEMENT MARKET	**10147**	**10147**	**10188**	**10152**	**10188**	**10196**	**10209**	**10184**	**8671**	**9252**	**9036**	**6715**	**9123**	**10085**	**9577.7**	**9670.4**

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 Exchange to reshape WB08 surplus to minimize deficit

3g Added Seasonal Exchange to account for WB vs AOP hydro generation shape differences.

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

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

3j 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(i).

3k 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(k).

TABLE 3
DETERMINATION OF LOADS FOR STEP II AND STEP III STUDIES
FOR 2013-14 AOP/DDPB 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	22202	97.37	28781	77.14	10613	18429.7	7816.9	15772.8	5159.9	August 1-15
August 16-31	22199	97.35	28713	77.31	10612	18427.0	7814.7	15770.4	5158.2	August 16-31
September	20865	91.50	26879	77.63	10654	17320.0	6665.8	14823.0	4168.8	September
October	21029	92.22	29039	72.42	10618	17455.7	6838.0	14939.2	4321.5	October
November	23328	102.30	32271	72.29	10654	19364.2	8709.7	16572.5	5918.1	November
December	25374	111.28	34488	73.57	10663	21062.2	10398.8	18025.7	7362.4	December
January	25899	113.58	35418	73.12	10676	21498.5	10822.2	18399.2	7722.8	January
February	24854	108.99	34047	73.00	10650	20630.5	9980.3	17656.3	7006.1	February
March	23021	100.96	31065	74.11	9099	19108.9	10009.5	16354.1	7254.6	March
April 1-15	21733	95.31	28914	75.16	9695	18040.1	8345.6	15439.3	5744.8	April 1-15
April 16-30	21757	95.41	28877	75.34	9473	18059.9	8586.7	15456.2	5983.1	April 16-30
May	21060	92.36	28057	75.06	7102	17481.5	10379.3	14961.3	7859.0	May
June	21629	94.85	28317	76.38	9575	17954.0	8378.7	15365.7	5790.3	June
July	22708	99.58	29730	76.38	10550	18849.2	8299.0	16131.8	5581.6	July
Annual Avg. 7/	22802.6	100.00		74.71	10030.7	18928.0	8897.3	16199.2	6168.5	Annual Avg
SI CP Avg (42.5)	22901.8			**74.60**	10125.5					<==Au31-Feb
S2 CP Avg (20)	22988.3				10147.4	19082.1	8934.7			<==Sep-Ap30
S3 CP Avg.(5.5)	24246.1				10282.4			17224.6	6942.3	<==Nov-Ap15
						Input 5/=	**8934.70**	Input 6/=	**6942.28**	
August 1-31	22200.7	97.36	28781.4	77.23	10612.5	18428.3	7815.8	15771.6	5159.0	Aug. 1-31
April 1-30	21744.9	95.36	28914.1	75.25	9583.8	18050.0	8466.1	15447.8	5863.9	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 uses this load shape.
2/ The thermal installations include all thermal used to meet the Step I system load. (Table 2, line 1a).
3/ The total firm load for the Step II/III studies is computed to have the same shape as the PNW Area energy load.
4/ The Base System 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 2013-14 operating year. The critical period (CP) averages are for the historic water years.

TABLE 4
SUMMARY OF STEPS I, II, & III POWER REGULATIONS
FOR 2013-14 ASSURED OPERATING PLAN

	BASIC DATA		STEP I				STEP II (USA Optimum)					STEP III (USA Optimum)				
	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE kaf	hm³	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE kaf	hm³	JANUARY 1945 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE kaf	hm³	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	212	116	104	3008	3710	328	230	105
Kerr	3	160	1219	1504	176	124	1219	1504	178	113	129	1219	1504	176	154	120
Thompson Falls	6	85	0	0	85	56	0	0	85	53	58	0	0	82	64	56
Noxon Rapids	5	554	231	285	523	147	0	0	528	128	194	0	0	528	173	194
Cabinet Gorge	4	239	0	0	238	98	0	0	238	86	118	0	0	238	113	117
Albeni Falls	3	50	1155	1425	21	24	1155	1425	19	22	21	1155	1425	10	18	19
Box Canyon	4	74	0	0	71	46	0	0	70	45	48	0	0	68	57	46
Grand Coulee	24+3SS	6684	5185	6396	6360	2057	5072	6256	6364	1831	2404	5072	6256	5664	1217	2297
Chief Joseph	27	2535	0	0	2535	1066	0	0	2535	967	1304	0	0	2535	701	1232
Wells	10	840	0	0	840	420	0	0	840	388	488	0	0	840	287	441
Chelan	2	54	677	835	51	38	676	834	51	38	46	676	834	51	45	43
Rocky Reach	11	1267	0	0	1267	573	0	0	1267	529	691	0	0	1267	384	642
Rock Island	18	513	0	0	547	263	0	0	547	246	313	0	0	547	182	289
Wanapum	10	986	0	0	825	501	0	0	825	464	585	0	0	825	329	520
Priest Rapids	10	912	0	0	770	488	0	0	770	455	556	0	0	770	330	492
Brownlee	5	675	975	1203	675	243	974	1201	675	301	318	974	1201	675	259	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	769	0	0	1127	442	716
John Day	16	2484	535	660	2484	942	0	0	2484	917	1253	0	0	2484	683	1214
The Dalles	22+2F	2074	0	0	2074	750	0	0	2074	731	993	0	0	2074	564	970
Bonneville	18+2F	1088	0	0	1047	566	0	0	1047	549	681	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	22848	8935	11507	13000		22248	6942	10906
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/					12839	10125			12839	10147	10031			12839	10282	10031
3. TRANSMISSION LOSSES, HYDRO MAINTENANCE & PEAK RESERVES 4/					-6703	-697			-4360	0	0			-3872	0	0
4. TOTAL RESOURCES 5/					34630	20544			31326	19082	21538			31215	17224	20936
5. STEP I, II, & III SYSTEM LOADS 6/					30871	20544			29400	19082	18928			25162	17225	16199
6. SURPLUS (4 - 5)					3760	0			1926	0	2610			6053	0	4737
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		14-41				14-12					14-13				

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 & 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, & 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 onsame percent as WB08, i.e. approximately 11% of load for reserves and 5.1% of hydro capability for maintenance. Hydro maintenance energy losses are not included in Steps II & III. Energy reserves for thermal installations are included in the thermal installation energy forecast.
5/ 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 2013-14 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S.
(From proxy agreement in place of 14-42 30yr study)

B. Optimum Power Generation in the U.S. Only
(From 14-12 30yr study)

Determination of Dependable Capacity Credited to Canadian Storage (MW)

	(A)	(B)
Step II - Critical Period Average Generation 1/	8934.7	8934.7
Step III - Critical Period Average Generation 2/	6942.3	6942.3
Gain Due to Canadian Storage	1992.4	1992.4
Average Critical Period Load Factor in percent 3/	74.60	74.60
Dependable Capacity Gain 4/	2671.0	2671.0
Canadian Share of Dependable Capacity 5/	1335.5	1335.5

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

	(A)	(B)
Step II (with Canadian Storage) 1/		
Firm Energy 6/	n.a.	8897.9
Thermal Displacement Energy 7/	n.a.	2469.5
Remaining Usable Energy 8/	n.a.	55.9
System Average Annual Usable Energy	n.a.	11423.3
Step III (without Canadian Storage) 2/		
Firm Energy 6/	n.a.	6169.1
Thermal Displacement Energy 7/	n.a.	3920.9
Remaining Usable Energy 8/	n.a.	326.3
System Average Annual Usable Energy	n.a.	10416.3
Average Annual Usable Energy Gain 9/	1011.0	1007.0
Canadian Share of Average Annual Energy Gain 5/	505.5	503.5

1/ Step II values were obtained from from 14-42 proxy and 14-12 studies.
2/ Step III values were obtained from 14-13 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/ 30-year average firm load served; not exactly equal to Table 3 due to including 7 leap years .
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
COMPARISON OF RECENT DDPB STUDIES
(English and Metric units)

	2009-10	2010-11	2011-12	2012-13	2013-14
AVERAGE PNWA ENERGY LOAD					
Annual Load (MW)	22268.2	22033.0	21710.9	22614.8	22802.6
Annual/January Load (%)	87.5	88.1	87.9	88.1	88.0
Critical Period (CP) Load Factor (%)	73.9	75.9	76.1	74.9	74.6
Annual Firm Exports 1/	639.6	636.7	687.9	901.2	902.5
Annual Firm Surplus (MW) 2/	762.4	578.5	554.0	570.0	786.0
THERMAL INSTALLATIONS (MW) 3/					
January Peak Capability	9756.1	11761.8	11454.7	12878.0	12838.8
CP Energy	8890.7	9418.4	9480.3	10085.9	10125.5
CP Minimum Generation	196.5	212.2	211.2	228.7	228.1
Average Annual System Export Sales	144.3	332.8	231.9	207.0	227.0
Average Annual Displaceable Market	8504.0	8779.4	8968.9	9548.1	9577.7
HYDRO CAPACITY (MW)					
Total Installed	29689.0	29689.0	29322.0	29689.0	29689.0
Base System	23742.0	23742.0	23427.0	23742.0	23742.0
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	175663	175395	175361	175361.0	175361
Step I CP Average, cfs	115061	114765	114734	114734.0	114734
Step II CP Average, cfs	101961	101628	101578	101578.0	101578
Step III CP Average, cfs	56558	56079	56027	56027	56027
Step I 30-yr. Average Streamflow, m^3/s	4974.2	4966.6	4965.7	4965.7	4965.7
Step I CP Average, m3/s	3258.2	3249.8	3248.9	3248.9	3248.9
Step II CP Average, m3/s	2887.2	2877.8	2876.4	2876.4	2876.4
Step III CP Average, m3/s	1601.6	1588.0	1586.5	1586.5	1586.5
CAPACITY BENEFITS (MW)					
Step II CP Generation	9018.1	8998.2	8944.6	8940.2	8934.7
Step III CP Generation	7020.8	7000.1	6945.5	6962.9	6942.3
Step II Gain over Step III	1997.3	1998.1	1999.1	1977.3	1992.4
CANADIAN ENTITLEMENT	1352.3	1316.4	1314.0	1320.8	1335.5
Change due to Mica Reoperation	0.0	0.0	0.0	0.0	0.0
ENERGY BENEFITS (aMW) 5/					
Step II Annual Firm	8907.7	8981.9	8904.7	8902.5	8897.9
Step II Thermal Displacement	2444.1	2414.7	2448.7	2484.0	2469.5
Step II Remaining Usable Secondary	87.6	67.2	69.1	55.9	55.9
Step II System Average Annual Usable	11439.4	11463.8	11422.5	11422.5	11423.3
Step III Annual Firm	6174.1	6324.3	6227.6	6233.5	6169.1
Step III Thermal Displacement	3707.8	3699.3	3776.2	3874.9	3920.9
Step III Remaining Usable Secondary	423.2	368.7	366.8	325.0	326.3
Step III System Average Annual Average	10305.1	10392.3	10370.6	10433.4	10416.3
CANADIAN ENTITLEMENT	567.1	535.7	525.9	504.5	505.5
Change due to Mica Reoperation	3.9	2.0	2.0	1.6	2.0
STEP II PEAK CAPABILITY (MW)	30529.8	30601.0	29985.0	31439.1	31326.1
STEP II PEAK LOAD (MW)	28996.3	28258.0	28338.0	29264.7	29400.1
STEP III PEAK CAPABILITY (MW)	30370.5	30571.0	29855.0	31289.3	31215.0
STEP III PEAK LOAD (MW)	23142.0	24155.0	24195.0	25128.7	25161.6

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)
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.
2013-14	1243 Aug 15, 1665 Aug 31, 243 Sep, 1633 Apr 30, 924 May, 3937 June, and 1212 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 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, 2012-13, and 2013-14 DDPBs include updated adjustments for the Grand Coulee pumping but not for return flows.

5. The Step II energy benefits for 2013-14 are based on 30-Year USA Optimum Hydroregulation studies.

CHART 1
DURATION CURVES OF 30-YEAR MONTHLY HYDRO GENERATION
From 2013-14 DDPB USA Optimum Steps II and III studies
(Average monthly MW)