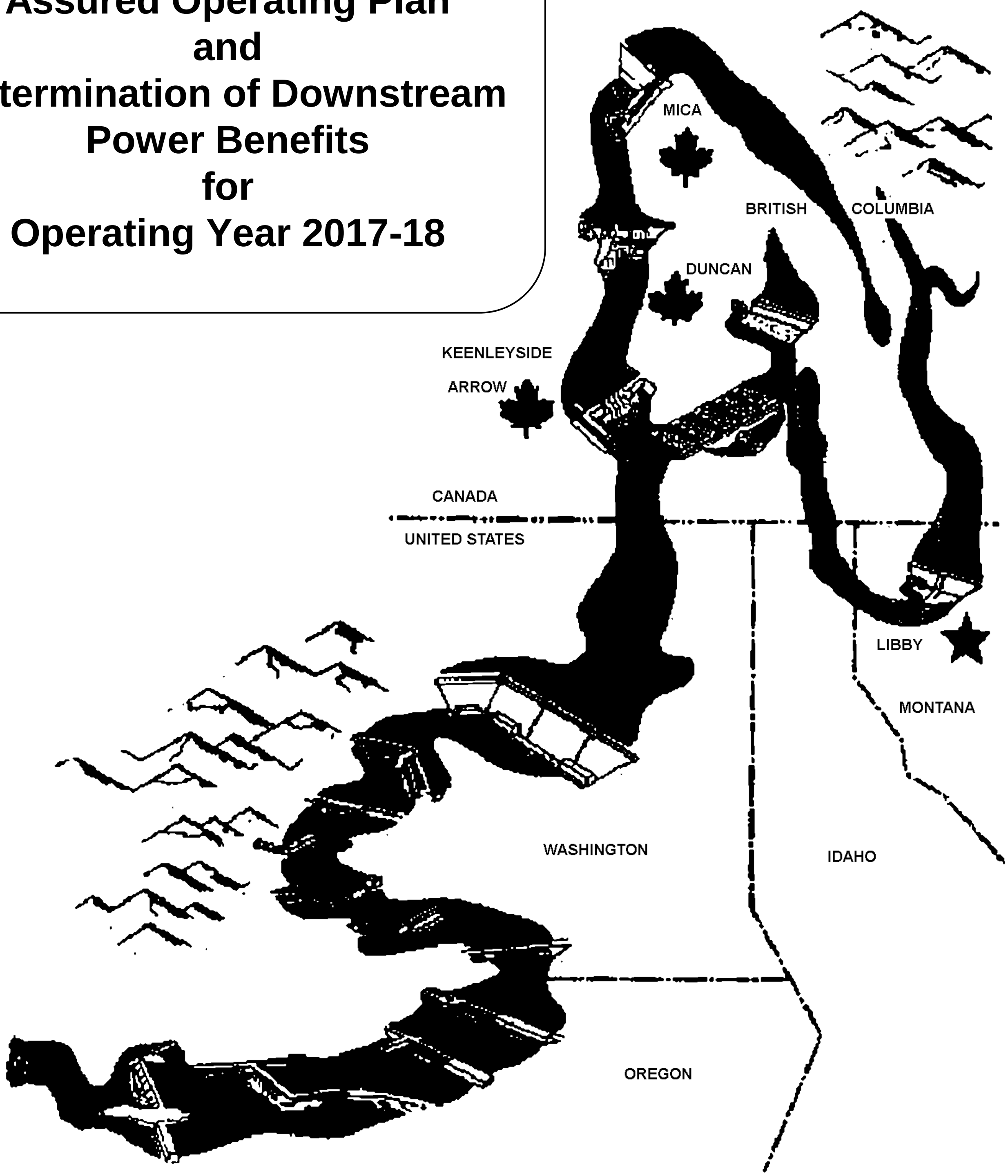
COLUMBIA RIVER TREATY
Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2017-18



Columbia River Treaty Operating Committee

April 2013

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COLUMBIA RIVER TREATY ENTITY AGREEMENT ON THE ASSURED OPERATING PLAN AND DETERMINATION OF DOWNSTREAM POWER BENEFITS FOR OPERATING YEAR 2017-18

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

The Entities agree that the attached reports entitled "Columbia River Treaty Hydroelectric Operating Plan: Assured Operating Plan for Operating Year 2017-18" and "Columbia River Treaty Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 2017-18," both dated April 2013, shall be the Assured Operating Plan and Determination of Downstream Power Benefits for the 2017-18 Operating Year.

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

Executed for the Canadian Entity this 10th day of APRIL, 2013.

By: ____________________
Chris K. O'Riley
Chair

Executed for the United States Entity this 12th day of APRIL, 2013.

By: ____________________
William K. Drummond
Chairman

By: ____________________
Brigadier General Anthony C. Funkhouser
Member

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COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

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HYDROELECTRIC OPERATING PLAN
ASSURED OPERATING PLAN
FOR OPERATING YEAR 2017-18

April 2013

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 the Entities designated by the two governments will formulate and carry out operating arrangements necessary to implement the Treaty and will agree on an Assured Operating Plan (AOP) for the Treaty storage in Canada (Canadian Treaty Storage) and resulting downstream power benefits for the sixth succeeding operating year. This AOP for operating year 2017-18 (AOP18) 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 September 2011 update to Appendix 1 - Refill Curves; the November 2004 additions of Appendix 6 - Streamline Procedures and Appendix 7 - Table of Median Streamflows; and in Appendix 8 the September 2007 addition concerning Water

Supply Forecasts and the February 2012 revision of Summary of Errors and Hedges in Table 1.

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 May 2003 Columbia River Treaty Flood Control Operating Plan (FCOP).

For this AOP, the Entities have agreed to use the first of the three streamline procedures defined in Appendix 6 of the POP. This streamline procedure includes "Forecasting Loads and Resources" for determining the thermal installations, as described in Subsection 7(d) of this document.

In addition, the Entities have agreed to add to or modify certain procedures defined in POP as follows:

- Allocate available uncommitted PNWA resources and available uncommitted imports from Canada and California to balance the White Book (WB) firm load/resource deficit, as was done since the AOP/DDPB13, as described in Subsections 7(b) and 7(d), and include the allocated Canadian import into the load/resource balance and the allocated PNWA thermal resources in the determination of the generic thermal installation shape.

- Exclude seasonal exchanges for balancing WB loads and resources (the same as in AOP16 and AOP17);

- Update thermal installation maintenance schedules per the 1 February 2012 data submittal, adjusted as in AOP17, as described in Subsection 7(d);

- Shape generic thermal installations based on the full amount of WB large thermal, co-generation and combustion turbines and 30% of unreported CT energy capability that are estimated to be needed to meet the WB load, as described in Subsection 7(d); and

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 (AOP18-41) 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 AOP18 are based on 2017-18 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.

In accordance with Protocol VIII, the AOP18 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 2010 level[3] and including updated estimates of Grand Coulee net pumping requirements.

The CRCs were determined from critical period studies 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 kilometer (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 AOP18, the Columbia River Treaty Operating Committee agreed that the three quantities would be assigned the following relative values:

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

The sum of the three weighted quantities showed a net gain in the Joint Optimum Study compared to the USA Optimum Study. The Entities agree that this result is in accordance with Subsection 3.2.A of the POP. The results of these calculations are shown in Table 2.

(2) Maximum Permitted Reduction in Downstream Power Benefits

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. Separate Step II system regulation studies were developed reflecting: (i) Canadian Treaty Storage operation for optimum generation in the USA alone; and (ii) Canadian Treaty Storage operation for optimum generation in both Canada and the USA. Using the storage operation for the optimum generation in both Canada and the USA, there is a 1.3 aMW increase in the Canadian Entitlement for average annual usable energy and a 1.3 aMW increase in the dependable capacity compared to the operation for optimum generation in the USA alone. (See Table 5 of DDPB18, columns A and B.)

Since there is no reduction in entitlement, the Entities have determined in Section 4 of the DDPB18 that the calculation of maximum permitted reduction in downstream power benefits is not necessary.

3. Rule Curves

The operation of Canadian Treaty Storage during the 2017-18 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 hydro regulation 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 or 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 Power Discharge Requirements (PDR) are determined in accordance with Section 2.3.B and the updated Appendix 1 of the POP. The 1930-31 inflows are the second lowest January through July unregulated streamflows at The Dalles, Oregon, during the 30-year (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 are interpolated linearly between the values shown in Tables 4-6. In those years when the January through July runoff volume at The Dalles is 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, are used. For AOP18, as was used since AOP12, the VRC Lower Limit (VRCLL) was applied as a fixed rule curve for Grand Coulee only.

Tables 4-6 illustrate the range of VRCs for Mica, Arrow, and Duncan for the 30-year stream flow period. In actual operation in 2017-18, 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 streamflows 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 maximum end-of-period storage contents 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 in all periods. 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

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 AOP18-41 system regulation study will apply to the operation of Canadian Treaty Storage in the 2017-18 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

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 either a target flow or target content, as listed in Table 1 and 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 Subsections 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 AOP18 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 Subsections 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 1.1(a) 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 1.1(a). To assist implementation of this procedure, an example is shown at the bottom of Table 1.1(c).

d) <u>Other Canadian Project Operation</u>

Revelstoke, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile, and Waneta are included in the AOP18 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 2017-18 DOP (DOP18) 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 DOP18. Failing agreement on updating the data and/or criteria, the DOP18 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 2017 -18 Operating Year shall be guided by the DOP18.

The values used in the AOP studies to define the various rule curves are 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, for 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 2017-18.”

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 2017 through 31 July 2018 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 2016-17 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 AOP18 are based on Bonneville Power Administration's (BPA) April 2011 White Book (WB11)[5] expected load forecast. The WB11 forecast for the 2017-18 regional firm load is 23,273 annual aMW, which is 10 aMW lower than the AOP17. There were minor changes to the Idaho portion of the Utah Power & Light load and to the Coulee pumping requirements, leading to a decrease in the net PNWA firm load by 26 annual aMW from the AOP17 to AOP18.

The average critical period load factor increased from 74.03% in AOP17 to 74.60% in AOP18. This was mainly due to changes in the energy and 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 AOP18, the estimate of the amount of Canadian Entitlement energy and other uncommitted imports that would be assumed to serve load in the PNWA were based on a similar procedure being used since AOP13, except that since AOP16, the use of added seasonal exchanges to balance firm WB loads and resources has been eliminated. This procedure assumes all of the Canadian Entitlement is returned to Canada, but is then available as an uncommitted import for the PNWA. The procedure determines the WB11 firm energy deficit without uncommitted thermal resources and then uses an allocation procedure of uncommitted resources to eliminate the deficit. The first step eliminates monthly deficits by proportionally allocating uncommitted PNWA resources (without unreported CT capability) and Canadian imports based on their availability. For the AOP18, this procedure resulted in 28% (130 annual aMW) of the available Canadian import being used for serving PNWA load. The allocated amount of uncommitted PNWA resources (without unreported CT capability) is used in the determination of the shape of the generic thermal installation, as discussed in Subsection 7(d). 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 AOP17, this procedure results in a 105 annual aMW decrease in Entitlement energy serving load in the U.S.

- The estimated Canadian Entitlement included in export loads was 469 annual aMW of energy and 1303 MW of capacity. The amount computed for the DDPB18 is 475.0 annual aMW of energy and 1304.1 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 noticeably impact the results of the studies.
- For the AOP18, as was the case since AOP15, a seasonal exchange to reshape the residual hydro load to reflect differences between AOP and WB hydro capabilities was not used. In addition, the AOP18 did not use seasonal exchanges to balance the firm WB loads and resources, as it has been since AOP16.
- Compared to the AOP17, power flows-out (exports that are mostly to the southwest but also include the Entitlement) decreased by 116 annual aMW, and power flows-in (imports) decreased by 167 annual aMW. These differences are primarily due to changes in WB imports and exports and the assumed amount of Canadian import.

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 AOP18, these resources have increased by 117 annual aMW over the AOP17. This is primarily due to an increase of renewables in AOP18.

Firm wind is included in AOP18 resources from the draft 2012 WB as approved at the May 2012 CRTOC meeting. In the draft 2012 WB, firm wind is the monthly wind generation that occurred in the operating year with the lowest total PNWA wind generation. This is a change from earlier WB studies which used average wind.

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 since AOP07. The procedure includes the Columbia Generating Station (CGS) 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 (2016-17 and 2017-18) maintenance cycle at CGS was used, which resulted in the same annual average generation for AOP17 and AOP18.

For the AOP18, as in the AOP16 and AOP17, it was agreed that the coordinated thermal installations used to determine the shape of the generic thermal installation for the AOP load and resource balance are the full amount of WB11 large thermal, co-generation, and combustion turbines and 30% of unreported CT energy capability (as described in Subsection 7(b)) that are estimated to be needed to meet the WB11 load.

The total thermal installations decreased by only 1 annual aMW from AOP17 to AOP18, as shown in DDPB Section 7(b), due to a combination of all changes in loads and resources as explained above. However, changes in thermal maintenance resulted in increased thermal generation March – April and reduced generation May – June.

e) Hydro Project Modified Streamflows

The unregulated base streamflows used in the system regulation studies were updated to the 2010 Modified Streamflows published by BPA in August 2011. Modified Streamflows are determined from historic observed streamflows, adjusted to remove the historic storage regulation effect at modeled upstream projects, and modified to a common level of irrigation depletions (2010 level) and reservoir evaporation. Additionally, the flows were further adjusted to include net Grand Coulee pumping updates from the PNCA 1 February 2012 data submittal. Pumping decreased overall from the 1 February 2010 data submittal used in AOP17 (1 February 2011 data submittal was not used for comparison due to scheduled canal maintenance). Additional changes include;

- The White River project was decommissioned and removed entirely from the 2010 Modified Streamflows and the AOP18 Step I project files.

- The 2010 modified flows above Brownlee are significantly lower than the 2000 modified flows data set. The 2010 modified flows incorporate the current level of irrigation development which better reflects the effects of groundwater pumping and is considered a more accurate estimation of 2010 conditions[6].

f) Hydro Project Rule Curves

AOP18 did not utilize the Streamline Procedure “Multi-Year Use of Same Operating Criteria for Canadian Treaty Storage”; instead, the full Step I, II, and III hydro regulation studies were performed per the 2003 Principles and Procedures document. Changes and 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 (373.4 m (1225.0 ft) for March to April, 378.0 m (1240.0 ft) for May, and 391.7 m (1285.0 ft) for June);

- The URC flood control data was developed by the Corps of Engineers using the 2010 Modified Streamflows, consistent with current AOP operating criteria (including 4.08/3.6 Mica/Arrow flood control allocation, Libby standard flood control, Hungry Horse variable flood control, 1998 Brownlee procedures, and no Dworshak/Brownlee shift) and in coordination with all Treaty parties. Studies assumed the 1938 IJC Order on Kootenay Lake does not affect Libby or Duncan operation, and both projects will be regulated to their flood control curves as required by their storage reservation diagrams[7]. Duncan end of February flood control rule curve was be limited to no lower than 552.5 m (1812.5 ft), (227.8 hm^3

(93.1 ksfd) usable storage), in accordance with the SRD updated November 2009;

- Monthly distribution factors based on the 2010 Modified Flows were updated as approved in the May 2012 CRTOC meeting;

- Hedges (also called forecast errors) for Libby were updated per the 1 February 2011 data submittal, then further updated to reflect a Libby forecast revision as approved in the March 2012 CRTOC meeting;

- HYDSIM Corra Linn '5-Step Logic' was not used in the AOP18. This change reflects current operating practices, and was approved at the May 2012 CRTOC meeting. Prior to AOP18, Libby and Duncan discharges were reduced through a step-wise modeling procedure whenever the level of Kootenay Lake exceeded its IJC Rule Curve level;

- For the AOP18 Critical Period Study, the March ARC contents at Grand Coulee are 5732.6 hm^3 (2343.1 ksfd) and 5593.9 hm^3 (2286.4 ksfd) for Steps I and II, respectively. These March ARC storage limits were based on the average of the AOP12, 14 and 15 ARCs from the ARC optimization study, and limited by flood control. Up to the AOP15, the March ARCs were calculated using the final ARCs from the previous AOP study. However, from AOP11 to AOP15, this procedure resulted in significant year-to-year reductions in the March ARC contents at Grand Coulee, which may potentially reduce system firm and secondary energy. The revised procedure from AOP16 was intended to avoid this impact;

- To save time, Composite Canadian crossovers during September, October, November and February between the second and third year of the Step I Critical Period were left in the USA Optimum study as agreed by both Entities;

- The Refill Study was performed for each Step of the AOP18. These PDRs were developed by the Corps of Engineers using the Corps' HYSSR model for each cyclic reservoir contained in the study, starting with minimum flows and increasing PDRs for individual projects as needed to pass the Refill Test.

g) <u>Other Hydro Project Operating Procedures, Constraints, and Plant Data</u>

The AOP18 hydro project operating procedures, constraints and plant data were updated from the PNCA 1 February 2011 and 2012 data submittals in accordance with POP procedures, except as noted below.

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 no longer has an at-site minimum flow requirement but is required to support a year-round flow of 184 m^3/s (6500 cfs) at Hells Canyon for navigation purposes, based on the 1988 Agreement between the Corps of Engineers and Idaho Power Company as well as the proposed license modeling criteria of the Hells Canyon FERC license application;

- 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;

- Hungry Horse is operated to a maximum flow of 269.0 m^3/s (9500 cfs) for Step I to reflect transmission constraints with Libby;

- 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 AOP06 because they are no longer coordinated resources in PNCA Planning. Although included in the Step I hydro regulation model, these projects are now essentially the same as a hydro-independent project;

- Head vs. Generation per Flow tables (h/k) were updated or corrected for Arrow (Step I and II), Noxon (Step I, II, and III), and Long Lake (Step I) per the 1 February 2012 data submittal;

- Discharge vs. Generation tables were updated or corrected for Cabinet Gorge (Step I), Little Falls (Step I), Monroe (Step I), Nine Mile (Step I), Post Falls (Step I), Upper Falls (Step I), Rocky Reach (Step I, II, and III), Rock Island (Step I, II, and III), and Brilliant (Step I, II, and III) per the 1 February 2012 data submittal;

- Discharge vs. Spill Table tables were updated or corrected for Cabinet Gorge (Step I), Little Falls (Step I), Monroe(Step I), Nine Mile (Step I), Post Falls (Step I), Upper Falls (Step I), Rocky Reach (Step I, II, and III), Rock Island (Step I, II, and III), and Brilliant (Step I, II, and III) per the 1 February 2012 data submittal;

- Head vs. Maximum Generation table updated or corrected for Arrow (Step I and II) and Revelstoke (Step I);

- Storage limits table in Step I changed slightly for Upper Baker and Lower Baker per the 1 February 2012 data submittal;

- Fish spill values and spill caps were updated for Little Goose, Lower Monumental, and Lower Granite. Fish spill was extended from August 15 to August 31, decreasing the average annual energy and surplus by a small amount;

- The ‘Noxon Special Logic’ was removed because the updated h/k provided by Avista Utilities made the logic obsolete. Originally the logic was used to reduce the calculated generation at higher flows;

- Ross and Gorge operating data were updated to the 1 February 2012 data submittal which included an update to the required flows for fish on the Skagit River (slightly higher flow requirement for Chum Salmon). Also, an increase to minimum flows January-April at Gorge occurred via the 1 February 2011 data submittal; and

- Hydro-independent projects are updated for the 2010 Modified Flows, resulting in slightly lower average generation.

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[1] "BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 18-41," dated 22 January 2013.

[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] Bonneville Power Administration (BPA) (2011). 2010 Level Modified Streamflow, 1928-2008. DOE/BP-4352. Portland, Oregon.

[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] October 2010 Final Study #67 of the "2010 Pacific Northwest Loads & Resources Study, Operating Years 2010 through 2019".

[6] US Bureau of Reclamation (USBR) (2010). Modified and Naturalized Flows of the Snake River Basin above Brownlee Reservoir. Pacific Northwest Regional Office, Boise, Idaho.

[7] "Comparative AOP16 Studies with and without the Corra Linn 5 Step Logic," prepared by BPA, dated 17 May 2012.

TABLE 1
(English Units)
MICA PROJECT OPERATING CRITERIA
2017-18 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	-	3,494.1	-	34,000	15,000
	2,490 - 3,300	28,000	-	0	-	15,000
	0 - 2,490	32,000	-	0	-	15,000
August 16-31	3,400 - FULL	-	3529.2	-	34000	15,000
	2,600 - 3,400	24,000	-	0	-	15,000
	2,000 - 2,600	29,000	-	0	-	15,000
	0 - 2,000	32,000	-	0	-	15,000
September	3,000 - FULL	-	3,529.2	-	34,000	10,000
	1,600 - 3,000	27,000	-	0	-	10,000
	0 - 1,600	32,000	-	0	-	10,000
October	3,000 - FULL	-	3,404.1	-	34,000	10,000
	1,600 - 3,000	23,000	-	0	-	10,000
	1,080 - 1,600	24,000	-	0	-	10,000
	0 - 1,080	32,000	-	0	-	10,000
November	3,100 - FULL	19,000	-	0	-	10,000
	2,770 - 3,100	21,000	-	0	-	10,000
	1000 - 2,770	26,000	-	0	-	10,000
	0 - 1,000	32,000	-	0	-	10,000
December	2,510 - FULL	23,000	-	204.1	-	10,000
	2,460 - 2,510	28,000	-	204.1	-	10,000
	400 - 2,460	29,000	-	204.1	-	10,000
	0 - 400	32,000	-	204.1	-	10,000
January	2,170 - FULL	24,000	-	204.1	-	12,000
	1,950 - 2,170	21,000	-	204.1	-	12,000
	1,870 - 1,950	27,000	-	204.1	-	12,000
	0 - 1,870	29,000	-	204.1	-	12,000
February	1,350 - FULL	23,000	-	0	-	12,000
	920 - 1,350	25,000	-	0	-	12,000
	350 - 920	27,000	-	0	-	12,000
	0 - 350	29,000	-	0	-	12,000
March	500 - FULL	10,000	-	0	-	12,000
	340 - 500	17,000	-	0	-	12,000
	170 - 340	23,000	-	0	-	12,000
	0 - 170	26,000	-	0	-	12,000
April 1-15	650 - FULL	15,000	-	0	-	12,000
	340 - 650	12,000	-	0	-	12,000
	170 - 340	20,000	-	0	-	12,000
	0 - 170	26,000	-	0	-	12,000
April 16-30	720 - FULL	10,000	-	0	-	10,000
	570 - 720	15,000	-	0	-	10,000
	0 - 570	10,000	-	0	-	10,000
May	580 - FULL	8,000	-	0	-	8,000
	550 - 580	10,000	-	0	-	8,000
	250 - 550	8,000	-	0	-	8,000
	0 - 250	10,000	-	0	-	8,000
June	1,350 - FULL	8,000	-	0	-	8,000
	1,130 - 1,350	10,000	-	0	-	8,000
	0 - 1,130	16,000	-	0	-	8,000
July	2,900 - FULL	-	3436.2	-	34000	10,000
	2,300 - 2,900	17,000	-	0	-	10,000
	0 - 2,300	32,000	-	0	-	10,000

Notes:

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
2017-18 ASSURED OPERATING PLAN

Period	Vol Runoff Period	The Dalles Vol Runoff (Maf)	Max Storage Limit 1/, 2/ (ksfd)	Max Outflow Limit 3/ (cfs)	Min Outflow Limit 4/ (cfs)
August 15 - December	-		URC	-	10,000.0
January	-		URC	70,000	10,000.0
February	1 Feb - 31 Jul	≤ 70	URC	60,000	20,000.0
		>70 to <80	URC to 1500.0		
		≥ 80	1500.0		
March	1 Mar - 31 Jul	≤ 65	URC	-	20,000.0
		>65 to <75	URC to 900.0		
		≥ 75	900.0		
April 15	1 Apr - 31 Jul	≤ 60	URC	-	15,000.0
		>60 to <65	URC to 900.0		
		≥ 65	900.0		
April 30	1 Apr - 31 Jul	≤ 60	URC	-	12,000.0
		>60 to <65	URC to 800.0		
		≥ 65	800.0		
May	1 May - 31 Jul	≤ 65	URC	-	5,000.0
		>65 to <70	URC to 2200.0		
		≥ 70	2200.0		
June	1 Jun - 31 Jul	≤ 37	URC	-	5,000.0
		>37 to <40	URC to 3300.0		
		≥ 40	3300.0		
July	-		URC	-	10,000.0

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 1500 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 2017-18 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	12,000	5,000	5,000	10,000
End-of-Period Maximum Storage Limits (ksfd)									
1928-29	-	-	URC	URC	URC	URC	URC	URC	-
1929-30	-	-	URC	URC	URC	URC	URC	URC	-
1930-31	-	-	URC	URC	URC	URC	URC	URC	-
1931-32	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1932-33	-	-	1500.0	900.0	900.0	800.0	URC	URC	-
1933-34	-	-	1500.0	900.0	900.0	800.0	URC	URC	-
1934-35	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1935-36	-	-	1500.0	900.0	900.0	800.0	URC	URC	-
1936-37	-	-	URC	URC	URC	URC	URC	URC	-
1937-38	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1938-39	-	-	1914.5	1185.2	900.0	800.0	URC	URC	-
1939-40	-	-	2032.0	1584.1	1864.3	1821.2	URC	URC	-
1940-41	-	-	URC	URC	URC	URC	URC	URC	-
1941-42	-	-	1500.0	900.0	900.0	800.0	URC	URC	-
1942-43	-	-	1500.0	900.0	900.0	800.0	2200.0	3300.0	-
1943-44	-	-	URC	URC	URC	URC	URC	URC	-
1944-45	-	-	1792.2	1217.1	900.0	800.0	URC	3507.1	-
1945-46	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1946-47	-	-	1500.0	900.0	900.0	800.0	2200.0	3343.7	-
1947-48	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1948-49	-	-	1500.0	900.0	900.0	800.0	2666.6	URC	-
1949-50	-	-	1500.0	900.0	900.0	800.0	URC	URC	-
1950-51	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1951-52	-	-	1500.0	900.0	900.0	800.0	2200.0	3335.8	-
1952-53	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1953-54	-	-	1500.0	900.0	900.0	800.0	URC	URC	-
1954-55	-	-	1500.0	900.0	900.0	800.0	URC	3300.0	-
1955-56	-	-	1500.0	900.0	900.0	800.0	2200.0	3300.0	-
1956-57	-	-	1500.0	900.0	900.0	800.0	2200.0	3336.7	-
1957-58	-	-	1500.0	900.0	900.0	800.0	2200.0	3568.7	-

TABLE 1.1c
APOC IMPLEMENTATION
DISTRIBUTION FACTORS FOR THE DALLES
2017-18 ASSURED OPERATING PLAN

Forecast Date	Forecast Period	The Dalles Distribution Factors 1/ Jan-Jul	Feb-Jul	Mar-Jul	Apr-Jul	May-Jul	Jun-Jul
1-Jan	1 Jan - 31 Jul	1.0000	0.9440	0.8860	0.8080	0.6800	0.4270
1-Feb	1 Feb - 31 Jul		1.0000	0.9390	0.8560	0.7200	0.4520
1-Mar	1 Mar - 31 Jul			1.0000	0.9120	0.7670	0.4810
1-Apr	1 Apr - 31 Jul				1.0000	0.8410	0.5280
1-May	1 May - 31 Jul					1.0000	0.6280
1-Jun	1 Jun - 31 Jul						1.0000

Notes:

1/ Unless otherwise agreed, the DOP18 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 2010 Modified Flows mean 80 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 = 64 Maf (May-Jul)	The Dalles Distribution Factor	Month-Jul Volume Runoff (Maf)	Month-Jul Volume Runoff (km^3)	The Dalles Volume Runoff (Maf)	The Dalles Volume Runoff (km^3)	Maximum Storage Limit (ksfd)	Maximum Storage Limit (hm^3)
May	1.0000	64.0	78.9	$\leq$ 65	$\leq$ 80.2	URC	URC
June	0.6280	40.2	49.6	$\geq$ 40	$\geq$ 49.3	3300	8073.7

TABLE 2
COMPARISON OF 2015-16 ASSURED OPERATING PLAN
STUDY RESULTS (USED FOR THE 2017-18 ASSURED OPERATING PLAN)

Study 18-41 provides Optimum Generation in Canada and in the United States.
Study 18-11 provides Optimum Generation in the United States only.

	Study No. 18-41	Study No. 18-11	Net Gain	Weight	Value
1. Firm Energy Capability (aMW)					
U.S. System 1/	11821.4	11821.9	-0.5		
Canada 2/, 3/	3028.6	3010.1	18.6		
Total	14850.0	14832.0	18.0	3	54.0
2. Dependable Peaking Capacity (MW)					
U.S. System 4/	29409.6	29402.7	6.9		
Canada 2/, 5/	6432.9	6395.7	37.2		
Total	35842.5	35798.4	44.1	1	44.1
3. Average Annual Usable Secondary Energy (aMW)					
U.S. System 6/	3315.0	3292.3	22.7		
Canada 2/, 7/	289.0	313.1	-24.1		
Total	3604.0	3605.4	-1.4	2	-2.8
			Net Change in Value =		95.3

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 15 August 1931.

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)
2017 - 18 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	3361.5	3067.0	2614.2	1489.2	958.8	783.8	788.1	775.8	384.1	685.5	2332.8	3429.1
1929-30	3529.2	3520.6	3275.7	2984.9	2358.8	1775.8	607.2	40.8	0.0	0.0	219.4	870.4	2371.2	3324.1
1930-31	3529.2	3529.2	3369.1	3057.5	2496.6	1665.1	770.2	187.1	0.0	0.0	0.0	673.2	2034.2	2553.7
1931-32	2582.1	2536.1	2089.1	1648.9	1121.9	253.7	0.0	0.0						
							ARROW							
1928-29	3579.6	3579.6	3513.0	3571.7	3484.4	3497.7	2190.0	831.7	410.7	315.2	746.8	1824.6	3363.4	3522.7
1929-30	3579.1	3499.9	2950.2	2296.8	1756.8	1283.9	513.5	88.8	0.0	104.9	453.6	1551.2	2653.4	3258.1
1930-31	3378.9	3466.4	3179.6	2686.6	1981.7	1450.4	679.6	114.2	0.0	0.0	0.1	768.8	1837.0	2133.4
1931-32	1821.1	1627.8	1414.4	1114.9	318.4	0.0	0.0	0.0						
							DUNCAN							
1928-29	705.8	705.8	625.0	600.0	550.0	450.0	250.0	93.0	102.0	107.5	118.8	236.3	511.1	698.0
1929-30	700.0	675.0	550.0	500.0	450.0	300.0	100.0	75.0	0.0	13.4	46.5	161.5	381.1	550.0
1930-31	600.0	600.0	525.0	450.0	400.0	200.0	75.0	25.0	0.0	4.8	0.0	157.2	395.1	500.0
1931-32	550.0	550.0	450.0	350.0	150.0	0.0	0.0	0.0						
							COMPOSITE							
1928-29	7814.6	7814.6	7499.5	7238.7	6648.6	5436.9	3398.8	1708.5	1300.8	1198.5	1249.7	2746.4	6207.3	7649.8
1929-30	7808.3	7695.5	6775.9	5781.7	4565.6	3359.7	1220.7	204.6	0.0	118.3	719.5	2583.1	5405.7	7132.2
1930-31	7508.1	7595.6	7073.7	6194.1	4878.3	3315.5	1524.8	326.3	0.0	4.8	0.1	1599.2	4266.3	5187.1
1931-32	4953.2	4713.9	3953.5	3113.8	1590.3	253.7	0.0	0.0						

Note: Individual project rule curves are input to the AOP18 Step 1 study and adjusted to eliminate any Canadian composite crossovers according to Subsection 3(a) of this AOP18 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
2017 - 18 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	589.3	767.7	832.7	848.9	843.6	832.0	838.6	863.7	927.0	1500.4	2706.0	3529.2
VARIABLE REFILL CURVES (KSFD)														
1928-29							2057.0	1875.8	1818.8	1811.0	1854.8	2366.8	2986.3	3529.2
1929-30							1033.6	812.1	746.6	757.0	917.1	1763.0	2696.2	"
1930-31							1291.8	1079.5	1009.1	997.8	1091.6	1781.9	2772.5	"
1931-32							474.2	268.6	205.4	194.9	316.0	1118.6	2520.1	"
1932-33							380.6	210.5	164.6	152.0	233.5	1017.9	2353.9	"
1933-34							0.0	0.0	0.0	0.0	0.0	764.9	2611.0	"
1934-35							724.1	535.4	501.5	508.9	582.7	1296.7	2459.8	"
1935-36							546.5	358.1	313.1	300.1	399.0	1283.4	2739.4	"
1936-37							2043.8	1841.9	1770.1	1751.4	1843.3	2379.0	3018.6	"
1937-38							753.4	564.9	501.4	495.4	592.0	1341.9	2613.9	"
1938-39							1048.3	904.2	847.9	862.5	977.2	1756.8	2993.0	"
1939-40							829.8	648.8	610.1	618.7	751.9	1554.4	2748.2	"
1940-41							1477.1	1285.6	1234.5	1242.5	1422.8	2158.8	3000.3	"
1941-42							1223.8	1036.2	976.9	961.7	1041.1	1712.0	2795.5	"
1942-43							1391.0	1180.9	1118.4	1103.0	1258.4	1967.1	2857.4	"
1943-44							2149.6	1932.1	1873.8	1864.2	1935.5	2488.2	3161.3	"
1944-45							1992.7	1812.2	1767.8	1768.9	1821.3	2330.7	3049.1	"
1945-46							174.2	0.0	0.0	0.0	0.0	818.0	2515.9	"
1946-47							288.1	122.5	86.6	85.4	206.1	1077.7	2585.6	"
1947-48							236.9	50.7	0.0	0.0	56.6	874.0	2469.8	"
1948-49							1935.2	1725.2	1645.5	1629.6	1709.7	2244.7	3258.6	"
1949-50							592.8	367.4	292.3	269.8	358.3	1094.3	2277.0	"
1950-51							584.1	406.4	363.4	358.6	476.1	1213.0	2646.5	"
1951-52							991.2	771.3	702.4	674.1	759.2	1507.2	2797.1	"
1952-53							1272.7	1071.0	1011.3	995.7	1058.6	1661.8	2763.3	"
1953-54							147.4	0.0	0.0	0.0	1.5	790.5	2248.5	"
1954-55							908.0	734.1	691.2	688.4	778.3	1433.8	2447.2	"
1955-56							455.9	263.9	200.8	180.8	273.4	1111.3	2559.2	"
1956-57							624.7	425.5	376.9	369.1	462.1	1197.1	2897.1	"
1957-58							458.2	271.9	229.9	227.5	336.6	1094.3	2654.3	"
DISTRIBUTION FACTORS							0.9760	0.9790	0.9750	0.9820	0.9650	0.7920	0.5060	N/A
FORECAST ERRORS (KSFD)							727.9	521.8	455.2	420.2	420.2	401.4	397.0	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	9600	20000	30000
VARIABLE REFILL CURVES					80	MAF	3000	3000	3000	3000	3000	3000	20000	27200
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	3000	3000	3000	3000	3000	3000	12000	23000
					110	MAF	3000	3000	3000	3000	3000	3000	12000	23000
VARIABLE REFILL CURVE LOWER LIMITS (KSFD)					80	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					110	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (KSFD)							421.6	22.5	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
2017 - 18 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	0.0	514.0	661.8	743.3	824.0	992.8	2267.6	3507.2	3579.6
VARIABLE REFILL CURVES (KSFD)														
1928-29							2683.4	2461.2	2346.6	2276.2	2406.9	3197.5	3570.7	3579.6
1929-30							999.9	826.2	868.8	873.7	1145.6	2586.4	3368.3	"
1930-31							1504.2	1281.7	1188.2	1151.8	1369.6	2441.5	3379.0	"
1931-32							0.0	0.0	0.0	0.0	227.2	1660.1	3065.5	"
1932-33							375.4	326.5	338.6	335.0	551.4	1804.4	3000.0	"
1933-34							0.0	0.0	0.0	0.0	158.0	2270.7	3494.5	"
1934-35							637.6	577.6	686.1	710.2	898.5	2019.1	3113.4	"
1935-36							697.0	540.5	493.6	461.5	633.5	2007.9	3412.6	"
1936-37							2992.4	2725.7	2600.5	2501.4	2653.4	3371.6	3579.6	"
1937-38							988.8	897.3	913.6	946.0	1173.8	2304.5	3311.0	"
1938-39							1230.9	1058.0	975.8	940.6	1235.0	2531.2	3579.6	"
1939-40							882.0	786.4	834.4	921.9	1202.4	2310.5	3448.8	"
1940-41							2139.1	1965.9	1909.8	1995.1	2436.1	3482.1	3579.6	"
1941-42							2110.4	1941.9	1879.1	1810.0	2016.4	2984.6	"	"
1942-43							2570.9	2333.9	2245.3	2160.9	2460.0	3479.7	"	"
1943-44							3504.1	3291.3	3189.3	3093.1	3264.1	3579.6	"	"
1944-45							2862.1	2694.6	2617.9	2575.7	2701.7	3389.2	"	"
1945-46							99.2	153.9	117.5	96.6	431.7	1784.6	3203.5	"
1946-47							720.4	679.7	682.8	705.2	960.4	2204.4	3302.6	"
1947-48							500.3	551.7	547.5	487.1	688.5	1899.2	3230.8	"
1948-49							2245.8	2041.5	1974.9	1916.6	2153.0	3214.3	3579.6	"
1949-50							573.6	457.6	473.4	474.0	678.5	1820.6	2876.1	"
1950-51							877.0	794.4	835.4	800.5	1048.1	2173.6	3373.5	"
1951-52							942.4	786.9	806.2	779.4	968.1	2226.6	3433.7	"
1952-53							1602.1	1409.8	1356.2	1298.6	1452.0	2490.6	3380.7	"
1953-54							0.0	0.0	5.1	10.6	302.9	1526.9	2885.2	"
1954-55							652.3	591.8	630.6	606.0	821.9	1894.3	2855.5	"
1955-56							355.9	253.0	271.4	266.3	502.6	1894.2	3233.3	"
1956-57							424.6	302.9	313.3	296.7	526.0	1751.1	3552.3	"
1957-58							223.5	116.5	172.7	239.8	535.7	1780.7	3269.7	"
DISTRIBUTION FACTORS							0.9730	0.9760	0.9700	0.9740	0.9510	0.7420	0.4670	N/A
FORECAST ERRORS (KSFD)							1485.1	1095.3	954.2	809.7	809.7	723.2	679.4	N/A
POWER DISCHARGE REQUIREMENTS (CFS):														
ASSURED REFILL CURVE														
	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	9500	33000	60000
VARIABLE REFILL CURVES					80	MAF	5000	5000	5000	5000	5000	5000	31000	50000
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	5000	5000	5000	5000	5000	5000	31000	50000
					110	MAF	5000	5000	5000	5000	5000	5000	31000	50000
VARIABLE REFILL CURVE LOWER LIMITS (KSFD)					80	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					110	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (KSFD)							411.3	37.5	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
2017 - 18 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	1.3	32.0	49.5	60.7	70.9	80.1	94.2	105.0	120.6	277.8	503.7	705.8
VARIABLE REFILL CURVES (KSFD)														
1928-29							349.0	332.0	340.3	338.2	354.8	460.7	595.8	705.8
1929-30							347.4	330.0	338.1	335.6	359.8	480.9	607.6	"
1930-31							291.8	275.7	287.4	290.0	312.7	430.9	595.8	"
1931-32							16.8	2.3	21.1	29.2	64.5	249.0	505.6	"
1932-33							0.0	0.0	0.0	0.0	0.0	75.0	367.5	"
1933-34							33.4	36.2	60.2	74.4	120.7	328.3	578.1	"
1934-35							82.2	72.9	95.8	97.6	121.8	286.5	500.7	"
1935-36							58.5	43.4	55.0	55.5	83.0	283.2	557.3	"
1936-37							284.7	266.8	277.1	275.0	296.0	416.0	577.1	"
1937-38							76.9	68.7	84.8	93.3	123.5	297.9	534.3	"
1938-39							129.4	118.9	131.7	135.2	166.9	338.1	581.0	"
1939-40							116.3	110.7	131.2	144.2	178.6	341.0	567.1	"
1940-41							200.5	192.1	208.5	223.2	268.7	420.3	590.3	"
1941-42							194.6	188.6	204.8	208.4	237.7	383.8	570.9	"
1942-43							206.8	193.5	208.4	210.4	249.2	405.5	563.5	"
1943-44							355.1	342.7	355.7	355.5	379.1	487.6	626.9	"
1944-45							277.7	265.6	279.7	280.1	298.3	416.7	585.2	"
1945-46							0.0	0.0	0.0	0.0	0.0	190.6	503.3	"
1946-47							"	"	"	"	30.6	234.6	513.0	"
1947-48							39.8	28.6	46.4	47.0	71.9	251.9	527.9	"
1948-49							266.1	249.8	261.4	260.2	285.5	422.6	630.1	"
1949-50							66.2	50.4	64.6	64.0	90.5	255.7	463.2	"
1950-51							0.0	0.0	0.0	0.0	31.9	220.3	495.4	"
1951-52							97.0	83.3	100.8	101.2	127.1	312.8	546.3	"
1952-53							94.2	83.2	98.7	100.6	123.6	287.4	508.7	"
1953-54							0.0	0.0	0.0	0.0	0.0	150.2	438.2	"
1954-55							30.1	18.6	34.1	37.0	65.1	232.4	438.0	"
1955-56							0.0	0.0	0.0	0.0	0.0	200.9	496.2	"
1956-57							50.0	32.3	45.9	48.2	77.4	250.5	564.6	"
1957-58							0.0	0.0	0.0	0.0	2.6	190.5	516.4	"
DISTRIBUTION FACTORS							0.9740	0.9800	0.9760	0.9790	0.9570	0.7510	0.4810	N/A
FORECAST ERRORS (KSFD)							127.6	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	100	500	800
VARIABLE REFILL CURVES					80	MAF	100	100	100	100	100	100	1800	2500
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	100	100	100	100	100	100	1800	2500
					110	MAF	100	100	100	100	100	100	1800	2500
VARIABLE REFILL CURVE LOWER LIMITS (KSFD)					80	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(BY VOLUME RUNOFF AT THE DALLES)					95	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					110	MAF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (KSFD)							11.8	6.3	0.0	0.0				

TABLE 7
(English Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2017 - 18 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	3207.0	3094.5	2969.9	2969.9	2969.9	3311.0	3529.2	3529.2
1929-30	"	"	"	"	"	"	3155.2	2996.1	2819.7	2819.7	2819.7	2903.4	3283.0	"
1930-31	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3331.6	3529.2	"
1931-32	"	"	"	"	"	"	2698.3	2105.4	1472.2	1472.2	1472.2	2313.5	3451.1	"
1932-33	"	"	"	"	"	"	2691.3	2112.5	"	"	"	1661.5	3282.4	"
1933-34	"	"	"	"	"	"	"	"	"	1519.5	1984.4	3370.8	3529.2	"
1934-35	"	"	"	"	"	"	"	"	"	1472.2	1472.2	1918.6	3333.8	"
1935-36	"	"	"	"	"	"	2698.3	2105.4	"	"	1665.5	2827.7	3529.2	"
1936-37	"	"	"	"	"	"	3141.9	2970.8	2781.2	2781.2	2781.2	3001.8	"	"
1937-38	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	1984.4	"	"
1938-39	"	"	"	"	"	"	2854.7	2423.4	1946.5	1946.5	2014.6	3214.2	3420.0	"
1939-40	"	"	"	"	"	"	3013.4	2715.7	2397.6	2397.6	2397.6	3306.3	3429.6	"
1940-41	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3516.5	3529.2	"
1941-42	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	1955.6	3280.3	"
1942-43	"	"	"	"	"	"	"	"	"	1505.1	1712.9	2206.6	3284.4	"
1943-44	"	"	"	"	"	"	3331.6	3331.6	3331.6	3331.6	3331.6	3521.5	3529.2	"
1944-45	"	"	"	"	"	"	2839.7	2395.0	1903.2	1903.2	1903.2	2217.0	"	"
1945-46	"	"	"	"	"	"	2691.3	2112.5	1472.2	1472.2	1472.2	2712.5	"	"
1946-47	"	"	"	"	"	"	"	"	"	"	1503.0	2578.8	"	"
1947-48	"	"	"	"	"	"	2698.3	2105.4	"	"	1472.2	2327.9	"	"
1948-49	"	"	"	"	"	"	2691.3	2112.5	"	"	1498.9	2430.8	3527.1	"
1949-50	"	"	"	"	"	"	"	"	"	"	1472.2	1546.2	3126.0	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	2457.5	3529.2	"
1951-52	"	"	"	"	"	"	2698.3	2105.4	"	"	1577.1	2531.5	"	"
1952-53	"	"	"	"	"	"	2691.3	2112.5	"	"	1472.2	1932.9	3391.4	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	2144.8	2772.2	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	1472.2	3052.0	"
1955-56	"	"	"	"	"	"	2698.3	2105.4	"	"	"	2284.7	3529.2	"
1956-57	"	"	"	"	"	"	2691.3	2112.5	"	"	"	2984.1	"	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	2613.8	"	"

TABLE 8
(English Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2017 - 18 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	3191.1	3161.6	3129.1	3129.1	3129.1	3208.8	3579.6	3579.6
1929-30	"	"	"	"	"	"	3143.1	3070.3	2989.7	2989.7	2989.7	2990.3	"	"
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	2042.3	"	"
1932-33	"	"	"	"	"	"	2721.0	2267.2	"	"	"	1764.6	3211.2	"
1933-34	"	"	"	"	"	"	"	"	"	1779.1	2271.0	2436.1	3579.6	"
1934-35	"	"	"	"	"	"	"	"	"	1764.6	1764.6	2053.2	"	"
1935-36	"	"	"	"	"	"	2726.5	2261.7	"	"	1878.9	3113.1	"	"
1936-37	"	"	"	"	"	"	3130.6	3046.7	2953.7	2953.7	2953.7	2953.7	"	"
1937-38	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	1986.0	"	"
1938-39	"	"	"	"	"	"	2862.2	2535.6	2174.1	2174.1	2185.4	2396.2	"	"
1939-40	"	"	"	"	"	"	3009.3	2809.1	2594.8	2594.8	2594.8	3140.4	"	"
1940-41	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3416.6	"	"
1941-42	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	1969.7	2918.9	"
1942-43	"	"	"	"	"	"	"	"	"	"	2033.2	2494.2	3579.6	"
1943-44	"	"	"	"	"	"	3223.7	3223.7	3223.7	3223.7	3223.7	3223.7	"	"
1944-45	"	"	"	"	"	"	2849.3	2511.1	2136.7	2136.7	2136.7	2169.9	"	"
1945-46	"	"	"	"	"	"	2721.0	2267.2	1764.6	1764.6	1764.6	1878.9	"	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	2211.1	"	"
1947-48	"	"	"	"	"	"	2726.5	2261.7	"	"	"	1880.7	"	"
1948-49	"	"	"	"	"	"	2721.0	2267.2	"	"	1771.8	2915.3	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	1764.6	1764.6	2997.0	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	2138.5	3579.6	"
1951-52	"	"	"	"	"	"	2726.5	2261.7	"	"	1866.2	2830.0	"	"
1952-53	"	"	"	"	"	"	2721.0	2267.2	"	"	1764.6	2007.8	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	2111.3	2900.8	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	1764.6	3314.6	"
1955-56	"	"	"	"	"	"	2726.5	2261.7	"	"	"	2383.5	3579.6	"
1956-57	"	"	"	"	"	"	2721.0	2267.2	"	"	"	2646.7	"	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	2652.1	"	"

TABLE 9
(English Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2017 - 18 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	429.1	704.3	705.8
1929-30	"	"	"	"	"	"	408.7	322.6	322.6	322.6	322.6	357.1	577.0	"
1930-31	"	"	"	"	"	"	390.7	288.3	288.3	288.3	288.3	426.5	664.5	"
1931-32	"	"	"	"	"	"	277.3	93.2	65.7	65.7	66.9	277.0	626.8	"
1932-33	"	"	"	"	"	"	273.7	"	"	"	65.7	130.6	558.8	"
1933-34	"	"	"	"	"	"	"	"	"	90.2	168.0	422.2	657.4	"
1934-35	"	"	"	"	"	"	"	"	"	65.7	65.7	180.2	504.9	"
1935-36	"	"	"	"	"	"	277.3	"	"	69.3	127.5	390.9	697.8	"
1936-37	"	"	"	"	"	"	374.8	258.1	258.1	258.1	258.1	334.6	583.1	"
1937-38	"	"	"	"	"	"	290.1	115.9	97.0	97.0	97.0	250.4	584.8	"
1938-39	"	"	"	"	"	"	285.1	109.0	87.5	87.5	119.7	368.0	576.9	"
1939-40	"	"	"	"	"	"	301.1	126.5	111.4	111.4	111.4	321.7	596.3	"
1940-41	"	"	"	"	"	"	344.4	200.1	200.1	200.1	200.1	327.1	579.4	"
1941-42	"	"	"	"	"	"	326.1	165.6	165.1	165.1	165.1	278.5	501.6	"
1942-43	"	"	"	"	"	"	329.3	171.4	171.4	190.1	239.8	361.7	564.7	"
1943-44	"	"	"	"	"	"	412.5	327.2	327.2	327.2	327.2	386.6	617.6	"
1944-45	"	"	"	"	"	"	381.5	270.7	270.7	270.7	270.7	364.2	622.7	"
1945-46	"	"	"	"	"	"	273.7	93.2	65.7	65.7	79.2	360.9	698.4	"
1946-47	"	"	"	"	"	"	"	"	"	"	90.8	335.2	654.3	"
1947-48	"	"	"	"	"	"	277.3	"	"	"	65.7	281.3	673.3	"
1948-49	"	"	"	"	"	"	368.0	245.0	245.0	245.0	266.2	503.0	705.8	"
1949-50	"	"	"	"	"	"	273.7	93.2	65.7	65.7	65.7	105.5	476.7	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	291.7	560.6	"
1951-52	"	"	"	"	"	"	277.3	"	"	"	114.1	323.5	623.7	"
1952-53	"	"	"	"	"	"	273.7	"	"	"	65.7	188.8	493.2	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	252.5	539.2	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	65.5	462.6	"
1955-56	"	"	"	"	"	"	277.3	"	"	"	"	295.4	659.3	"
1956-57	"	"	"	"	"	"	273.7	"	"	"	71.2	399.5	705.8	"
1957-58	"	"	"	"	"	"	"	"	"	"	66.3	371.9	"	"

TABLE 10
(English Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN TREATY STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2017 - 18 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	3398.8	1756.7	1683.9	1795.2	2040.4	4045.8	6724.3	7814.6
1929-30	"	"	"	"	"	"	2208.7	1731.3	1591.9	1688.5	2030.5	"	6575.6	"
1930-31	"	"	"	"	"	"	2713.0	1756.7	1683.9	1795.2	2040.4	"	6596.1	"
1931-32	"	"	"	"	"	"	902.3	312.4	226.5	224.1	607.7	3027.7	6091.2	"
1932-33	"	"	"	"	"	"	844.7	543.3	503.2	487.0	784.9	2857.5	5721.4	"
1933-34	"	"	"	"	"	"	866.3	96.2	60.2	74.4	278.6	3310.3	6616.6	"
1934-35	"	"	"	"	"	"	1443.9	1185.9	1253.3	1284.8	1546.9	3496.0	6073.9	"
1935-36	"	"	"	"	"	"	1302.0	942.0	861.7	817.1	1115.5	3569.1	6629.7	"
1936-37	"	"	"	"	"	"	3398.8	1756.7	1683.9	1795.2	2040.4	4045.8	6724.3	"
1937-38	"	"	"	"	"	"	1819.1	1465.3	1329.5	1412.7	1681.8	3578.3	6436.0	"
1938-39	"	"	"	"	"	"	2319.1	1756.7	1669.4	1774.0	2039.5	4045.8	6724.3	"
1939-40	"	"	"	"	"	"	1828.1	1528.2	1455.4	1550.2	1856.1	"	6665.9	"
1940-41	"	"	"	"	"	"	3298.4	1756.7	1683.9	1795.2	2040.4	"	6724.3	"
1941-42	"	"	"	"	"	"	3263.8	"	"	"	"	3747.9	6126.5	"
1942-43	"	"	"	"	"	"	3355.6	"	"	"	"	4045.8	6724.3	"
1943-44	"	"	"	"	"	"	3398.8	"	"	"	"	"	"	"
1944-45	"	"	"	"	"	"	"	"	"	"	"	3948.1	"	"
1945-46	"	"	"	"	"	"	844.7	182.7	117.5	96.6	431.7	2793.2	6222.7	"
1946-47	"	"	"	"	"	"	1153.8	808.5	769.4	790.6	1197.1	3516.7	6399.3	"
1947-48	"	"	"	"	"	"	961.7	631.0	593.9	534.1	810.8	3006.6	6211.7	"
1948-49	"	"	"	"	"	"	3398.8	1756.7	1683.9	1795.2	2040.4	4045.8	6724.3	"
1949-50	"	"	"	"	"	"	1232.6	875.4	830.3	807.8	1102.5	2964.4	5616.3	"
1950-51	"	"	"	"	"	"	1472.9	1207.1	1106.7	1159.1	1500.8	3571.8	6515.4	"
1951-52	"	"	"	"	"	"	1998.2	1641.5	1511.4	1519.2	1841.4	4004.8	6650.8	"
1952-53	"	"	"	"	"	"	2655.1	1746.9	1647.6	1753.4	1985.5	3697.0	6579.9	"
1953-54	"	"	"	"	"	"	844.7	66.3	5.1	10.6	304.4	2467.6	5571.9	"
1954-55	"	"	"	"	"	"	1590.4	1344.5	1355.9	1331.4	1665.3	3263.9	5740.7	"
1955-56	"	"	"	"	"	"	879.0	523.2	472.2	447.1	776.0	3206.4	6288.7	"
1956-57	"	"	"	"	"	"	1099.3	760.7	736.1	714.0	1059.3	3198.7	6724.3	"
1957-58	"	"	"	"	"	"	881.3	394.7	402.6	467.3	874.9	3065.5	6435.1	"

TABLE 11
(English Units)
COMPOSITE END STORAGE
FOR THE WHOLE OF CANADIAN TREATY STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (KSFD)
2017 - 18 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7499.5	7238.7	6648.7	5436.9	3398.8	1708.5	1300.9	1198.4	1249.7	2746.4	6207.3	7649.8
1929-30	7808.3	7695.5	6726.0	5781.7	4565.6	3359.7	1220.7	204.6	0.0	118.3	719.5	2583.1	5405.7	7132.2
1930-31	7508.1	7595.6	7048.7	6194.1	4878.3	3315.4	1524.8	326.3	0.0	4.8	0.1	1599.2	4266.3	5187.1
1931-32	4953.2	4713.9	3953.5	3113.8	1590.3	253.7	0.0	0.0	1.7	121.6	460.8	2385.4	5823.9	7614.8
1932-33	7746.4	7814.6	6937.1	6351.7	6374.5	5162.9	3053.5	1405.5	503.2	438.5	646.2	2396.1	5721.4	7721.6
1933-34	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	3129.7	1546.7	769.8	606.1	1227.7	3310.3	6211.6	7615.2
1934-35	7772.5	7691.8	6775.9	6146.8	6501.5	5162.9	3063.5	1563.3	1226.9	1104.1	1244.8	3095.1	6073.9	7814.6
1935-36	7814.6	7793.4	7398.0	6657.0	5661.7	4163.5	1981.7	900.2	505.5	417.2	874.4	3569.1	6629.7	7721.6
1936-37	7795.2	7690.4	6775.9	5899.7	4678.3	3252.3	1194.8	185.2	0.0	8.7	52.7	1545.4	4547.7	5979.7
1937-38	5972.0	5836.0	5133.1	4501.8	3885.5	3073.1	1819.1	1448.7	780.8	679.9	587.9	2582.3	5756.2	7696.2
1938-39	7673.3	7640.6	7053.2	6609.9	5699.6	4675.0	2525.5	1731.2	1349.8	1382.0	1415.8	4045.8	6034.1	7721.6
1939-40	7808.6	7704.0	6834.1	6331.8	5784.8	5162.9	3038.8	1528.2	1273.0	1361.9	1676.2	4045.8	6052.9	7236.0
1940-41	7325.3	7246.9	6775.9	6702.5	5709.7	4460.2	2853.4	1546.4	1302.4	1519.2	1940.4	3064.3	4799.5	5714.6
1941-42	5559.1	5422.2	5075.4	5540.0	5102.0	5162.9	3283.4	1756.7	1091.6	976.8	879.5	2783.7	5144.0	7589.6
1942-43	7779.5	7771.0	7090.2	6420.0	6177.7	5162.9	3363.0	1756.7	1335.1	1406.8	1444.1	2807.0	5210.1	7721.6
1943-44	7814.6	7814.6	7431.8	7120.6	6503.2	5162.2	3382.6	1720.1	1208.1	1155.3	1174.2	2408.6	4571.9	5340.5
1944-45	5189.6	4985.9	4258.6	3657.8	2363.6	1010.7	204.1	0.0	0.0	0.8	0.0	1829.4	4796.5	6425.4
1945-46	6254.1	6066.9	5331.2	4656.0	3833.2	2974.5	844.7	182.7	0.0	0.0	283.0	2729.8	6200.2	7721.6
1946-47	7814.6	7799.3	7499.5	7120.6	6617.8	5162.9	2970.8	1325.3	769.4	790.6	1197.1	3516.7	6399.3	7814.6
1947-48	7814.6	7791.6	7499.5	7120.6	6617.8	5162.9	2997.3	1262.8	593.9	487.9	689.9	3006.6	6211.7	7814.6
1948-49	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	3398.8	1756.7	1363.1	1362.8	1505.7	4045.8	6373.8	7413.0
1949-50	7715.9	7674.4	6836.4	6325.3	6399.5	5162.9	2969.1	1306.7	827.6	766.4	835.7	2252.0	5616.3	7814.6
1950-51	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	3051.2	1440.1	997.4	1020.2	1157.8	3570.1	6194.3	7753.3
1951-52	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	2970.2	1641.5	1204.3	1138.4	1458.8	3830.8	6543.2	7721.6
1952-53	7814.6	7779.9	7208.8	6530.9	5541.6	4263.2	2720.2	1746.9	1330.0	1171.0	995.6	2872.8	5824.8	7721.6
1953-54	7805.1	7814.6	7499.5	7120.6	6617.8	5162.9	3029.5	1439.4	554.0	215.2	247.7	2467.6	5571.9	7814.6
1954-55	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	3077.4	1464.9	1068.4	1035.0	913.6	2071.9	5740.7	7721.6
1955-56	7814.6	7814.6	7499.5	7120.6	6617.8	5162.9	3023.0	1298.3	472.2	439.2	776.0	3206.4	6288.7	7721.6
1956-57	7779.5	7814.6	7499.5	7120.6	6617.8	5162.9	2990.4	1338.9	736.1	703.9	889.0	3198.7	6712.0	7721.6
1957-58	7769.6	7685.9	6924.2	6612.8	6063.6	5162.9	3019.8	1420.2	492.9	467.3	656.7	3065.5	6435.1	7721.6
Max	7814.6	7814.6	7499.5	7238.7	6648.7	5436.9	3398.8	1756.7	1363.1	1519.2	1940.4	4045.8	6712.0	7814.6
Median	7800.2	7775.5	7071.7	6611.4	6276.1	5162.9	2993.9	1439.8	775.3	735.2	884.3	2839.9	5929.5	7721.6
Average	7399.7	7351.5	6802.1	6320.0	5671.4	4439.0	2536.7	1231.8	768.6	736.6	906.7	2887.7	5778.8	7345.3
Min	4953.2	4713.9	3953.5	3113.8	1590.3	253.7	0.0	0.0	0.0	0.0	0.0	1545.4	4266.3	5187.1

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

	2010-11	2011-12 through 2013-14 1/	2014-15	2015-16 through 2016-17 3/	2017-18
MICA TARGET OPERATION (ksfd or cfs)					
AUG 15	3439.2	3364.2	3379.2	3379.2	3494.1
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	3428.4	3428.4	3428.4	3404.1	3404.1
NOV	21000	21000	22000	21000	19000
DEC	25000	25000	22000	17000	23000
JAN	27000	24000	24000	24000	24000
FEB	21000	21000	21000	26000	23000
MAR	21000	17000	25000	25000	10000
APR 15	22000	20000	17000	21000	15000
APR 30	10000	10000	10000	10000	10000
MAY	8000	8000	8000	8000	8000
JUN	8000	8000	10000	8000	8000
JUL	3467.2	3467.2	3467.2	3436.2	3436.2
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (ksfd)					
1928 AUG 31	7794.1	7814.4	7814.6	7814.6	7814.6
1928 DEC	5086	5204	5282.1	5092.5	5436.9
1929 APR15	1048.2	1084.4	1078.2	1024.5	1198.4
1929 JUL	7233.2	7329.8	7500.9	7585.9	7649.8
COMPOSITE CANADIAN TREATY STORAGE CONTENT (ksfd)					
Pre AOP15: 60-Yr Avg, AOP15 -17: 70-Yr Avg, AOP18: 80-Yr Avg 2/					
AUG 31	7438.0	7362.8	7406.8	7415.3	7385.9
DEC	4612.9	4630.0	4644.6	4490.1	4524.4
APR15	842.6	908.6	889.3	716.3	811.0
JUL	7268.9	7147.1	7279.9	7303.8	7388.7
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-0.3	0.1	0.0	0.0	-0.5
U.S. Dependable Peaking Capacity	-19.1	-22.9	-3.9	-2.1	6.9
U.S. Average Annual Usable Secondary Energy	16.0	21.6	21.3	17.6	22.7
BCH Firm Energy	34.4	43.6	44.0	24.0	18.6
BCH Dependable Peaking Capacity	43.8	41.7	47.8	28.2	37.2
BCH Average Annual Usable Secondary Energy	-20.8	-13.9	-33.4	-16.2	-24.1
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	11138	10969	11187	11367	12028
AUG 31	11167	11104	10971	10944	11399
SEP	11025	11081	9756	9822	10207
OCT	9958	9920	9758	10051	9233
NOV	11333	11458	11821	12152	11434
DEC	13369	13316	13836	13744	13523
JAN	13076	12878	13323	13933	13862
FEB	11902	11721	13179	12876	13006
MAR	10967	10501	12022	11269	11264
APR 15	10241	9786	10476	10894	9583
APR 30	12475	11502	11012	11600	10684
MAY	13493	13287	12198	12166	12344
JUN	14080	13867	12208	11291	11314
JUL	12725	12531	11954	11812	12256
ANNUAL AVERAGE	12039	11856	11819	11794	11689

1/ The AOP 2013-14 and 2012-13 utilize the same system regulation study as the 2011-12.

2/ Prior to AOP15, average content based on 60 years of modified flows. AOP15 through AOP17 averages based on 70 years of modified flows. AOP18 averages based on 80 years of modified flows.

3/ The AOP 2016-17 utilizes the same Step 1 system regulation studies as used in the AOP 2015-16, so these coordinated hydro loads will be used for the DOP17 TSR unless otherwise agreed.

TABLE 1M
(Metric Units)
MICA PROJECT OPERATING CRITERIA
2017-18 ASSURED OPERATING PLAN

		Target Operation		Target Operation Limits		
Month	End of Previous Month Arrow Storage Content (hm3)	Average Outflow (m^3/s)	End-of-Month Treaty Storage Content 1/ (hm3)	Minimum Treaty Storage Content 2/ (hm^3)	Maximum Outflow 1/ (m^3/s)	Minimum Outflow (m^3/s)
August 1-15	8,073.8 - FULL	-	8,548.7	-	962.77	424.75
	6,092.0 - 8,073.8	792.87	-	0.0	-	424.75
	0.0 - 6,092.0	906.14	-	0.0	-	424.75
August 16-31	8,318.4 - FULL	-	8,634.5	-	962.77	424.75
	6,361.2 - 8,318.4	679.60	-	0.0	-	424.75
	4,893.2 - 6,361.2	821.19	-	0.0	-	424.75
	0.0 - 4,893.2	906.14	-	0.0	-	424.75
September	7,339.8 - FULL	-	8,634.5	-	962.77	283.17
	3,914.6 - 7,339.8	764.55	-	0.0	-	283.17
	0.0 - 3,914.6	906.14	-	0.0	-	283.17
October	7,339.8 - FULL	-	8,328.5	-	962.77	283.17
	3,914.6 - 7,339.8	651.29	-	0.0	-	283.17
	2,642.3 - 3,914.6	679.60	-	0.0	-	283.17
	0.0 - 2,642.3	906.14	-	0.0	-	283.17
November	7,584.5 - FULL	538.02	-	0.0	-	283.17
	6,777.1 - 7,584.5	594.65	-	0.0	-	283.17
	2,446.6 - 6,777.1	736.24	-	0.0	-	283.17
	0.0 - 2,446.6	906.14	-	0.0	-	283.17
December	6,141.0 - FULL	651.29	-	499.4	-	283.17
	6,018.6 - 6,141.0	792.87	-	499.4	-	283.17
	978.6 - 6,018.6	821.19	-	499.4	-	283.17
	0.0 - 978.6	906.14	-	499.4	-	283.17
January	5,309.1 - FULL	679.60	-	499.4	-	339.80
	4,770.9 - 5,309.1	594.65	-	499.4	-	339.80
	4,575.1 - 4,770.9	764.55	-	499.4	-	339.80
	0.0 - 4,575.1	821.19	-	499.4	-	339.80
February	3,302.9 - FULL	651.29	-	0.0	-	339.80
	2,250.9 - 3,302.9	707.92	-	0.0	-	339.80
	856.3 - 2,250.9	764.55	-	0.0	-	339.80
	0.0 - 856.3	821.19	-	0.0	-	339.80
March	1,223.3 - FULL	283.17	-	0.0	-	339.80
	831.8 - 1,223.3	481.39	-	0.0	-	339.80
	415.9 - 831.8	651.29	-	0.0	-	339.80
	0.0 - 415.9	736.24	-	0.0	-	339.80
April 1-15	1,590.3 - FULL	424.75	-	0.0	-	339.80
	831.8 - 1,590.3	339.80	-	0.0	-	339.80
	415.9 - 831.8	566.34	-	0.0	-	339.80
	0.0 - 415.9	736.24	-	0.0	-	339.80
April 16-30	1,761.6 - FULL	283.17	-	0.0	-	283.17
	1,394.6 - 1,761.6	424.75	-	0.0	-	283.17
	0.0 - 1,394.6	283.17	-	0.0	-	283.17
May	1,419.0 - FULL	226.53	-	0.0	-	226.53
	1,345.6 - 1,419.0	283.17	-	0.0	-	226.53
	611.7 - 1,345.6	226.53	-	0.0	-	226.53
	0.0 - 611.7	283.17	-	0.0	-	226.53
June	3,302.9 - FULL	226.53	-	0.0	-	226.53
	2,764.7 - 3,302.9	283.17	-	0.0	-	226.53
	0.0 - 2,764.7	453.07	-	0.0	-	226.53
July	7,095.1 - FULL	-	8,407.0	-	962.77	283.17
	5,627.2 - 7,095.1	481.39	-	0.0	-	283.17
	0.0 - 5,627.2	906.14	-	0.0	-	283.17

Notes:

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 1.1aM
(Metric Units)
ARROW PROJECT OPERATING CRITERIA
DEFINITION
2017-18 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 >86 to <99 ≥ 99	URC URC to 3670.0 3670.0	1,699	566.3
March	1 Mar - 31 Jul	≤ 80 >80 to <93 ≥ 93	URC URC to 2202.0 2202.0	-	566.3
April 15	1 Apr - 31 Jul	≤ 74 >74 to <80 ≥ 80	URC URC to 2202.0 2202.0	-	424.8
April 30	1 Apr - 31 Jul	≤ 74 >74 to <80 ≥ 80	URC URC to 1957.0 1957.0	-	339.8
May	1 May - 31 Jul	≤ 80 >80 to <86 ≥ 86	URC URC to 5382.0 5382.0	-	141.6
June	1 Jun - 31 Jul	≤ 46 >46 to <49 ≥ 49	URC URC to 8074.0 8074.0	-	141.6
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 3670 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 2017-18 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	339.8	141.6	141.6	283.2
End-of-Period Maximum Storage Limits (hm^3)									
1928-29	-	-	URC	URC	URC	URC	URC	URC	-
1929-30	-	-	URC	URC	URC	URC	URC	URC	-
1930-31	-	-	URC	URC	URC	URC	URC	URC	-
1931-32	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1932-33	-	-	3669.9	2201.9	2201.9	1957.3	URC	URC	-
1933-34	-	-	3669.9	2201.9	2201.9	1957.3	URC	URC	-
1934-35	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1935-36	-	-	3669.9	2201.9	2201.9	1957.3	URC	URC	-
1936-37	-	-	URC	URC	URC	URC	URC	URC	-
1937-38	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1938-39	-	-	4684.0	2899.7	2201.9	1957.3	URC	URC	-
1939-40	-	-	4971.4	3875.6	4561.2	4455.7	URC	URC	-
1940-41	-	-	URC	URC	URC	URC	URC	URC	-
1941-42	-	-	3669.9	2201.9	2201.9	1957.3	URC	URC	-
1942-43	-	-	3669.9	2201.9	2201.9	1957.3	5382.5	8073.7	-
1943-44	-	-	URC	URC	URC	URC	URC	URC	-
1944-45	-	-	4384.8	2977.7	2201.9	1957.3	URC	8580.4	-
1945-46	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1946-47	-	-	3669.9	2201.9	2201.9	1957.3	5382.5	8180.6	-
1947-48	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1948-49	-	-	3669.9	2201.9	2201.9	1957.3	6524.0	URC	-
1949-50	-	-	3669.9	2201.9	2201.9	1957.3	URC	URC	-
1950-51	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1951-52	-	-	3669.9	2201.9	2201.9	1957.3	5382.5	8161.3	-
1952-53	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1953-54	-	-	3669.9	2201.9	2201.9	1957.3	URC	URC	-
1954-55	-	-	3669.9	2201.9	2201.9	1957.3	URC	8073.7	-
1955-56	-	-	3669.9	2201.9	2201.9	1957.3	5382.5	8073.7	-
1956-57	-	-	3669.9	2201.9	2201.9	1957.3	5382.5	8163.5	-
1957-58	-	-	3669.9	2201.9	2201.9	1957.3	5382.5	8731.1	-

TABLE 3M
(Metric Units)
CRITICAL RULE CURVES
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2017 - 18 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	8224.2	7503.7	6395.9	3643.5	2345.8	1917.6	1928.2	1898.1	939.7	1677.1	5707.4	8389.6
1929-30	8634.5	8613.5	8014.3	7302.9	5771.0	4344.7	1485.6	99.8	0.0	0.0	536.8	2129.5	5801.4	8132.7
1930-31	8634.5	8634.5	8242.8	7480.5	6108.2	4073.8	1884.4	457.8	0.0	0.0	0.0	1647.1	4976.9	6247.9
1931-32	6317.4	6204.8	5111.2	4034.2	2744.8	620.7	0.0	0.0						
							ARROW							
1928-29	8757.8	8757.8	8594.9	8738.5	8524.9	8557.5	5358.1	2034.8	1004.8	771.2	1827.1	4464.1	8228.9	8618.6
1929-30	8756.6	8562.9	7218.0	5619.4	4298.2	3141.2	1256.3	217.3	0.0	256.6	1109.8	3795.2	6491.8	7971.3
1930-31	8266.8	8480.9	7779.2	6573.0	4848.4	3548.5	1662.7	279.4	0.0	0.0	0.2	1880.9	4494.4	5219.6
1931-32	4455.5	3982.6	3460.5	2727.7	779.0	0.0	0.0	0.0						
							DUNCAN							
1928-29	1726.8	1726.8	1529.1	1468.0	1345.6	1101.0	611.6	227.5	249.6	263.0	290.7	578.1	1250.5	1707.7
1929-30	1712.6	1651.5	1345.6	1223.3	1101.0	734.0	244.7	183.5	0.0	32.8	113.8	395.1	932.4	1345.6
1930-31	1468.0	1468.0	1284.5	1101.0	978.6	489.3	183.5	61.2	0.0	11.7	0.0	384.6	966.7	1223.3
1931-32	1345.6	1345.6	1101.0	856.3	367.0	0.0	0.0	0.0						
							COMPOSITE							
1928-29	19119.2	19119.2	18348.3	17710.2	16266.5	13301.9	8315.5	4180.0	3182.5	2932.2	3057.5	6719.3	15186.8	18716.0
1929-30	19103.8	18827.8	16577.9	14145.5	11170.2	8219.8	2986.6	500.6	0.0	289.4	1760.3	6319.8	13225.6	17449.6
1930-31	18369.3	18583.4	17306.5	15154.5	11935.2	8111.7	3730.6	798.3	0.0	11.7	0.2	3912.6	10437.9	12690.8
1931-32	12118.5	11533.0	9672.6	7618.2	3890.8	620.7	0.0	0.0						

TABLE 4M
(Metric Units)
MICA
ASSURED AND VARIABLE REFILL CURVES, DISTRIBUTION FACTORS AND FORECAST ERRORS, POWER DISCHARGE REQUIREMENTS, AND OPERATING RULE CURVE LOWER LIMITS
2017 - 18 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	1441.8	1878.3	2037.3	2076.9	2064.0	2035.6	2051.7	2113.1	2268.0	3670.9	6620.5	8634.5
VARIABLE REFILL CURVES (hm^3)														
1928-29							5032.7	4589.3	4449.9	4430.8	4538.0	5790.6	7306.3	8634.5
1929-30							2528.8	1986.9	1826.6	1852.1	2243.8	4313.4	6596.5	"
1930-31							3160.5	2641.1	2468.9	2441.2	2670.7	4359.6	6783.2	"
1931-32							1160.2	657.2	502.5	476.8	773.1	2736.8	6165.7	"
1932-33							931.2	515.0	402.7	371.9	571.3	2490.4	5759.1	"
1933-34							0.0	0.0	0.0	0.0	0.0	1871.4	6388.1	"
1934-35							1771.6	1309.9	1227.0	1245.1	1425.6	3172.5	6018.1	"
1935-36							1337.1	876.1	766.0	734.2	976.2	3140.0	6702.2	"
1936-37							5000.4	4506.4	4330.7	4285.0	4509.8	5820.5	7385.3	"
1937-38							1843.3	1382.1	1226.7	1212.0	1448.4	3283.1	6395.2	"
1938-39							2564.8	2212.2	2074.5	2110.2	2390.8	4298.2	7322.7	"
1939-40							2030.2	1587.4	1492.7	1513.7	1839.6	3803.0	6723.7	"
1940-41							3613.9	3145.3	3020.3	3039.9	3481.0	5281.7	7340.5	"
1941-42							2994.1	2535.2	2390.1	2352.9	2547.2	4188.6	6839.5	"
1942-43							3403.2	2889.2	2736.3	2698.6	3078.8	4812.7	6990.9	"
1943-44							5259.2	4727.1	4584.4	4561.0	4735.4	6087.6	7734.4	"
1944-45							4875.3	4433.7	4325.1	4327.8	4456.0	5702.3	7459.9	"
1945-46							426.2	0.0	0.0	0.0	0.0	2001.3	6155.4	"
1946-47							704.9	299.7	211.9	208.9	504.2	2636.7	6325.9	"
1947-48							579.6	124.0	0.0	0.0	138.5	2138.3	6042.6	"
1948-49							4734.7	4220.9	4025.9	3987.0	4183.0	5491.9	7972.5	"
1949-50							1450.3	898.9	715.1	660.1	876.6	2677.3	5570.9	"
1950-51							1429.1	994.3	889.1	877.4	1164.8	2967.7	6474.9	"
1951-52							2425.1	1887.1	1718.5	1649.3	1857.5	3687.5	6843.4	"
1952-53							3113.8	2620.3	2474.2	2436.1	2590.0	4065.8	6760.7	"
1953-54							360.6	0.0	0.0	0.0	3.7	1934.0	5501.2	"
1954-55							2221.5	1796.0	1691.1	1684.2	1904.2	3507.9	5987.3	"
1955-56							1115.4	645.7	491.3	442.3	668.9	2718.9	6261.3	"
1956-57							1528.4	1041.0	922.1	903.0	1130.6	2928.8	7088.0	"
1957-58							1121.0	665.2	562.5	556.6	823.5	2677.3	6494.0	"
DISTRIBUTION FACTORS							0.9760	0.9790	0.9750	0.9820	0.9650	0.7920	0.5060	N/A
FORECAST ERRORS (hm^3)							1780.9	1276.6	1113.7	1028.1	1028.1	982.1	971.3	N/A
POWER DISCHARGE REQUIREMENTS (m^3/s):														
ASSURED REFILL CURVE														
	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	84.95	271.84	566.34	849.50
VARIABLE REFILL CURVES					98.68	km^3	85.0	85.0	85.0	85.0	85.0	85.0	566.3	770.2
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	85.0	85.0	85.0	85.0	85.0	85.0	339.8	651.3
					135.69	km^3	85.0	85.0	85.0	85.0	85.0	85.0	339.8	651.3
VARIABLE REFILL CURVE LOWER LIMITS (hm^3)					98.68	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					135.69	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (hm^3)							1031.5	55.0	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
2017 - 18 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	0.0	1257.6	1619.2	1818.6	2016.0	2429.0	5547.9	8580.7	8757.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							6565.2	6021.6	5741.2	5569.0	5888.7	7823.0	8736.1	8757.8
1929-30							2446.4	2021.4	2125.6	2137.6	2802.8	6327.9	8240.9	"
1930-31							3680.2	3135.8	2907.1	2818.0	3350.9	5973.4	8267.1	"
1931-32							0.0	0.0	0.0	0.0	555.9	4061.6	7500.1	"
1932-33							918.5	798.8	828.4	819.6	1349.1	4414.6	7339.8	"
1933-34							0.0	0.0	0.0	0.0	386.6	5555.5	8549.6	"
1934-35							1560.0	1413.2	1678.6	1737.6	2198.3	4939.9	7617.2	"
1935-36							1705.3	1322.4	1207.6	1129.1	1549.9	4912.5	8349.3	"
1936-37							7321.2	6668.7	6362.4	6119.9	6491.8	8249.0	8757.8	"
1937-38							2419.2	2195.3	2235.2	2314.5	2871.8	5638.2	8100.7	"
1938-39							3011.5	2588.5	2387.4	2301.3	3021.6	6192.8	8757.8	"
1939-40							2157.9	1924.0	2041.4	2255.5	2941.8	5652.9	8437.8	"
1940-41							5233.5	4809.8	4672.5	4881.2	5960.2	8519.3	8757.8	"
1941-42							5163.3	4751.1	4597.4	4428.3	4933.3	7302.1	"	"
1942-43							6290.0	5710.1	5493.4	5286.9	6018.6	8513.4	"	"
1943-44							8573.1	8052.5	7802.9	7567.6	7985.9	8757.8	"	"
1944-45							7002.4	6592.6	6405.0	6301.7	6610.0	8292.0	"	"
1945-46							242.7	376.5	287.5	236.3	1056.2	4366.2	7837.7	"
1946-47							1762.5	1663.0	1670.5	1725.3	2349.7	5393.3	8080.1	"
1947-48							1224.0	1349.8	1339.5	1191.7	1684.5	4646.6	7904.5	"
1948-49							5494.6	4994.7	4831.8	4689.2	5267.5	7864.1	8757.8	"
1949-50							1403.4	1119.6	1158.2	1159.7	1660.0	4454.3	7036.7	"
1950-51							2145.7	1943.6	2043.9	1958.5	2564.3	5317.9	8253.6	"
1951-52							2305.7	1925.2	1972.4	1906.9	2368.6	5447.6	8400.9	"
1952-53							3919.7	3449.2	3318.1	3177.2	3552.5	6093.5	8271.2	"
1953-54							0.0	0.0	12.5	25.9	741.1	3735.7	7058.9	"
1954-55							1595.9	1447.9	1542.8	1482.6	2010.9	4634.6	6986.3	"
1955-56							870.7	619.0	664.0	651.5	1229.7	4634.3	7910.6	"
1956-57							1038.8	741.1	766.5	725.9	1286.9	4284.2	8691.1	"
1957-58							546.8	285.0	422.5	586.7	1310.6	4356.7	7999.6	"
DISTRIBUTION FACTORS							0.9730	0.9760	0.9700	0.9740	0.9510	0.7420	0.4670	N/A
FORECAST ERRORS (hm^3)							3633.4	2679.8	2334.5	1981.0	1981.0	1769.4	1662.2	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	269.01	934.46	1699.01
VARIABLE REFILL CURVES					98.68	km^3	141.58	141.58	141.58	141.58	141.58	141.58	877.82	1415.84
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	141.58	141.58	141.58	141.58	141.58	141.58	877.82	1415.84
					135.69	km^3	141.58	141.58	141.58	141.58	141.58	141.58	877.82	1415.84
VARIABLE REFILL CURVE LOWER LIMITS (hm^3)					98.68	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					135.69	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (hm^3)							1006.3	91.7	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
2017 - 18 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	3.2	78.3	121.1	148.5	173.5	196.0	230.5	256.9	295.1	679.7	1232.4	1726.8
VARIABLE REFILL CURVES (hm^3)														
1928-29							853.9	812.3	832.6	827.4	868.1	1127.1	1457.7	1726.8
1929-30							849.9	807.4	827.2	821.1	880.3	1176.6	1486.6	"
1930-31							713.9	674.5	703.2	709.5	765.1	1054.2	1457.7	"
1931-32							41.1	5.6	51.6	71.4	157.8	609.2	1237.0	"
1932-33							0.0	0.0	0.0	0.0	0.0	183.5	899.1	"
1933-34							81.7	88.6	147.3	182.0	295.3	803.2	1414.4	"
1934-35							201.1	178.4	234.4	238.8	298.0	701.0	1225.0	"
1935-36							143.1	106.2	134.6	135.8	203.1	692.9	1363.5	"
1936-37							696.5	652.8	678.0	672.8	724.2	1017.8	1411.9	"
1937-38							188.1	168.1	207.5	228.3	302.2	728.8	1307.2	"
1938-39							316.6	290.9	322.2	330.8	408.3	827.2	1421.5	"
1939-40							284.5	270.8	321.0	352.8	437.0	834.3	1387.5	"
1940-41							490.5	470.0	510.1	546.1	657.4	1028.3	1444.2	"
1941-42							476.1	461.4	501.1	509.9	581.6	939.0	1396.8	"
1942-43							506.0	473.4	509.9	514.8	609.7	992.1	1378.7	"
1943-44							868.8	838.4	870.3	869.8	927.5	1193.0	1533.8	"
1944-45							679.4	649.8	684.3	685.3	729.8	1019.5	1431.8	"
1945-46							0.0	0.0	0.0	0.0	0.0	466.3	1231.4	"
1946-47							"	"	"	"	74.9	574.0	1255.1	"
1947-48							97.4	70.0	113.5	115.0	175.9	616.3	1291.6	"
1948-49							651.0	611.2	639.5	636.6	698.5	1033.9	1541.6	"
1949-50							162.0	123.3	158.1	156.6	221.4	625.6	1133.3	"
1950-51							0.0	0.0	0.0	0.0	78.0	539.0	1212.0	"
1951-52							237.3	203.8	246.6	247.6	311.0	765.3	1336.6	"
1952-53							230.5	203.6	241.5	246.1	302.4	703.2	1244.6	"
1953-54							0.0	0.0	0.0	0.0	0.0	367.5	1072.1	"
1954-55							73.6	45.5	83.4	90.5	159.3	568.6	1071.6	"
1955-56							0.0	0.0	0.0	0.0	0.0	491.5	1214.0	"
1956-57							122.3	79.0	112.3	117.9	189.4	612.9	1381.4	"
1957-58							0.0	0.0	0.0	0.0	6.4	466.1	1263.4	"
DISTRIBUTION FACTORS							0.9740	0.9800	0.9760	0.9790	0.9570	0.7510	0.4810	N/A
FORECAST ERRORS (hm^3)							312.2	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	2.83	14.16	22.65
VARIABLE REFILL CURVES					98.68	km^3	2.83	2.83	2.83	2.83	2.83	2.83	50.97	70.79
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	2.83	2.83	2.83	2.83	2.83	2.83	50.97	70.79
					135.69	km^3	2.83	2.83	2.83	2.83	2.83	2.83	50.97	70.79
VARIABLE REFILL CURVE LOWER LIMITS (hm^3)					98.68	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(BY VOLUME RUNOFF AT THE DALLES)					117.18	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					135.69	km^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OPERATING RULE CURVE LOWER LIMITS (hm^3)							28.9	15.4	0.0	0.0				

TABLE 7M
(Metric Units)
MICA
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2017 - 18 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8634.5	8634.5	8634.5	8387.9	8387.9	8151.1	7846.2	7571.0	7266.2	7266.2	7266.2	8100.7	8634.5	8634.5
1929-30	"	"	"	"	"	"	7719.5	7330.3	6898.7	6898.7	6898.7	7103.5	8032.2	"
1930-31	"	"	"	"	"	"	8151.1	8151.1	8151.1	8151.1	8151.1	8151.1	8634.5	"
1931-32	"	"	"	"	"	"	6601.7	5151.1	3601.9	3601.9	3601.9	5660.2	8443.5	"
1932-33	"	"	"	"	"	"	6584.5	5168.4	"	"	"	4065.0	8030.7	"
1933-34	"	"	"	"	"	"	"	"	"	3717.6	4855.0	8247.0	8634.5	"
1934-35	"	"	"	"	"	"	"	"	"	3601.9	3601.9	4694.0	8156.5	"
1935-36	"	"	"	"	"	"	6601.7	5151.1	"	"	4074.8	6918.3	8634.5	"
1936-37	"	"	"	"	"	"	7687.0	7268.4	6804.5	6804.5	6804.5	7344.2	"	"
1937-38	"	"	"	"	"	"	6584.5	5168.4	3601.9	3601.9	3601.9	4855.0	"	"
1938-39	"	"	"	"	"	"	6984.3	5929.1	4762.3	4762.3	4928.9	7863.9	8367.4	"
1939-40	"	"	"	"	"	"	7372.6	6644.2	5866.0	5866.0	5866.0	8089.2	8390.9	"
1940-41	"	"	"	"	"	"	8151.1	8151.1	8151.1	8151.1	8151.1	8603.5	8634.5	"
1941-42	"	"	"	"	"	"	6584.5	5168.4	3601.9	3601.9	3601.9	4784.6	8025.6	"
1942-43	"	"	"	"	"	"	"	"	"	3682.4	4190.8	5398.7	8035.6	"
1943-44	"	"	"	"	"	"	8151.1	8151.1	8151.1	8151.1	8151.1	8615.7	8634.5	"
1944-45	"	"	"	"	"	"	6947.6	5859.6	4656.4	4656.4	4656.4	5424.1	"	"
1945-46	"	"	"	"	"	"	6584.5	5168.4	3601.9	3601.9	3601.9	6636.4	"	"
1946-47	"	"	"	"	"	"	"	"	"	"	3677.2	6309.3	"	"
1947-48	"	"	"	"	"	"	6601.7	5151.1	"	"	3601.9	5695.4	"	"
1948-49	"	"	"	"	"	"	6584.5	5168.4	"	"	3667.2	5947.2	8629.4	"
1949-50	"	"	"	"	"	"	"	"	"	"	3601.9	3782.9	7648.1	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	6012.5	8634.5	"
1951-52	"	"	"	"	"	"	6601.7	5151.1	"	"	3858.5	6193.6	"	"
1952-53	"	"	"	"	"	"	6584.5	5168.4	"	"	3601.9	4729.0	8297.4	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	5247.5	6782.5	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	3601.9	7467.0	"
1955-56	"	"	"	"	"	"	6601.7	5151.1	"	"	"	5589.7	8634.5	"
1956-57	"	"	"	"	"	"	6584.5	5168.4	"	"	"	7300.9	"	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	6394.9	"	"

TABLE 8M
(Metric Units)
ARROW
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2017 - 18 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	8757.8	8757.8	8757.8	8449.6	8449.6	7887.1	7807.3	7735.2	7655.7	7655.7	7655.7	7850.6	8757.8	8757.8
1929-30	"	"	"	"	"	"	7689.9	7511.8	7314.6	7314.6	7314.6	7316.1	"	"
1930-31	"	"	"	"	"	"	7887.1	7887.1	7887.1	7887.1	7887.1	8757.8	"	"
1931-32	"	"	"	"	"	"	6670.7	5533.5	4317.3	4317.3	4317.3	4996.7	"	"
1932-33	"	"	"	"	"	"	6657.2	5546.9	"	"	"	4317.3	7856.5	"
1933-34	"	"	"	"	"	"	"	"	"	4352.7	5556.2	5960.2	8757.8	"
1934-35	"	"	"	"	"	"	"	"	"	4317.3	4317.3	5023.4	"	"
1935-36	"	"	"	"	"	"	6670.7	5533.5	"	"	4596.9	7616.5	"	"
1936-37	"	"	"	"	"	"	7659.3	7454.1	7226.5	7226.5	7226.5	7226.5	"	"
1937-38	"	"	"	"	"	"	6657.2	5546.9	4317.3	4317.3	4317.3	4858.9	"	"
1938-39	"	"	"	"	"	"	7002.7	6203.6	5319.2	5319.2	5346.8	5862.5	"	"
1939-40	"	"	"	"	"	"	7362.6	6872.7	6348.4	6348.4	6348.4	7683.3	"	"
1940-41	"	"	"	"	"	"	7887.1	7887.1	7887.1	7887.1	7887.1	8359.1	"	"
1941-42	"	"	"	"	"	"	6657.2	5546.9	4317.3	4317.3	4317.3	4819.1	7141.4	"
1942-43	"	"	"	"	"	"	"	"	"	"	4974.4	6102.3	8757.8	"
1943-44	"	"	"	"	"	"	7887.1	7887.1	7887.1	7887.1	7887.1	7887.1	"	"
1944-45	"	"	"	"	"	"	6971.1	6143.7	5227.6	5227.6	5227.6	5308.9	"	"
1945-46	"	"	"	"	"	"	6657.2	5546.9	4317.3	4317.3	4317.3	4596.9	"	"
1946-47	"	"	"	"	"	"	"	"	"	"	"	5409.7	"	"
1947-48	"	"	"	"	"	"	6670.7	5533.5	"	"	"	4601.3	"	"
1948-49	"	"	"	"	"	"	6657.2	5546.9	"	"	4334.9	7132.6	"	"
1949-50	"	"	"	"	"	"	"	"	"	"	4317.3	4317.3	7332.5	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	5232.1	8757.8	"
1951-52	"	"	"	"	"	"	6670.7	5533.5	"	"	4565.8	6923.9	"	"
1952-53	"	"	"	"	"	"	6657.2	5546.9	"	"	4317.3	4912.3	"	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	5165.5	7097.1	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	4317.3	8109.5	"
1955-56	"	"	"	"	"	"	6670.7	5533.5	"	"	"	5831.5	8757.8	"
1956-57	"	"	"	"	"	"	6657.2	5546.9	"	"	"	6475.4	"	"
1957-58	"	"	"	"	"	"	"	"	"	"	"	6488.6	"	"

TABLE 9M
(Metric Units)
DUNCAN
UPPER RULE CURVES (FLOOD CONTROL)
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2017 - 18 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	1049.8	1723.1	1726.8
1929-30	"	"	"	"	"	"	999.9	789.3	789.3	789.3	789.3	873.7	1411.7	"
1930-31	"	"	"	"	"	"	955.9	705.4	705.4	705.4	705.4	1043.5	1625.8	"
1931-32	"	"	"	"	"	"	678.4	228.0	160.7	160.7	163.7	677.7	1533.5	"
1932-33	"	"	"	"	"	"	669.6	"	"	"	160.7	319.5	1367.2	"
1933-34	"	"	"	"	"	"	"	"	"	220.7	411.0	1033.0	1608.4	"
1934-35	"	"	"	"	"	"	"	"	"	160.7	160.7	440.9	1235.3	"
1935-36	"	"	"	"	"	"	678.4	"	"	169.5	311.9	956.4	1707.2	"
1936-37	"	"	"	"	"	"	917.0	631.5	631.5	631.5	631.5	818.6	1426.6	"
1937-38	"	"	"	"	"	"	709.8	283.6	237.3	237.3	237.3	612.6	1430.8	"
1938-39	"	"	"	"	"	"	697.5	266.7	214.1	214.1	292.9	900.3	1411.4	"
1939-40	"	"	"	"	"	"	736.7	309.5	272.6	272.6	272.6	787.1	1458.9	"
1940-41	"	"	"	"	"	"	842.6	489.6	489.6	489.6	489.6	800.3	1417.6	"
1941-42	"	"	"	"	"	"	797.8	405.2	403.9	403.9	403.9	681.4	1227.2	"
1942-43	"	"	"	"	"	"	805.7	419.3	419.3	465.1	586.7	884.9	1381.6	"
1943-44	"	"	"	"	"	"	1009.2	800.5	800.5	800.5	800.5	945.9	1511.0	"
1944-45	"	"	"	"	"	"	933.4	662.3	662.3	662.3	662.3	891.1	1523.5	"
1945-46	"	"	"	"	"	"	669.6	228.0	160.7	160.7	193.8	883.0	1708.7	"
1946-47	"	"	"	"	"	"	"	"	"	"	222.2	820.1	1600.8	"
1947-48	"	"	"	"	"	"	678.4	"	"	"	160.7	688.2	1647.3	"
1948-49	"	"	"	"	"	"	900.3	599.4	599.4	599.4	651.3	1230.6	1726.8	"
1949-50	"	"	"	"	"	"	669.6	228.0	160.7	160.7	160.7	258.1	1166.3	"
1950-51	"	"	"	"	"	"	"	"	"	"	"	713.7	1371.6	"
1951-52	"	"	"	"	"	"	678.4	"	"	"	279.2	791.5	1525.9	"
1952-53	"	"	"	"	"	"	669.6	"	"	"	160.7	461.9	1206.7	"
1953-54	"	"	"	"	"	"	"	"	"	"	"	617.8	1319.2	"
1954-55	"	"	"	"	"	"	"	"	"	"	"	160.3	1131.8	"
1955-56	"	"	"	"	"	"	678.4	"	"	"	"	722.7	1613.0	"
1956-57	"	"	"	"	"	"	669.6	"	"	"	174.2	977.4	1726.8	"
1957-58	"	"	"	"	"	"	"	"	"	"	162.2	909.9	"	"

TABLE 10M
(Metric Units)
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN TREATY STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2017 - 18 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	8315.5	4297.9	4119.8	4392.1	4992.0	9898.5	16451.7	19119.2
1929-30	"	"	"	"	"	"	5403.8	4235.8	3894.7	4131.1	4967.8	"	16087.9	"
1930-31	"	"	"	"	"	"	6637.6	4297.9	4119.8	4392.1	4992.0	"	16138.0	"
1931-32	"	"	"	"	"	"	2207.6	764.3	554.2	548.3	1486.8	7407.6	14902.7	"
1932-33	"	"	"	"	"	"	2066.6	1329.2	1231.1	1191.5	1920.3	6991.2	13998.0	"
1933-34	"	"	"	"	"	"	2119.5	235.4	147.3	182.0	681.6	8099.0	16188.2	"
1934-35	"	"	"	"	"	"	3532.6	2901.4	3066.3	3143.4	3784.6	8553.3	14860.4	"
1935-36	"	"	"	"	"	"	3185.5	2304.7	2108.2	1999.1	2729.2	8732.2	16220.2	"
1936-37	"	"	"	"	"	"	8315.5	4297.9	4119.8	4392.1	4992.0	9898.5	16451.7	"
1937-38	"	"	"	"	"	"	4450.6	3585.0	3252.8	3456.3	4114.7	8754.7	15746.3	"
1938-39	"	"	"	"	"	"	5673.9	4297.9	4084.4	4340.3	4989.8	9898.5	16451.7	"
1939-40	"	"	"	"	"	"	4472.6	3738.9	3560.8	3792.7	4541.1	"	16308.8	"
1940-41	"	"	"	"	"	"	8069.9	4297.9	4119.8	4392.1	4992.0	"	16451.7	"
1941-42	"	"	"	"	"	"	7985.2	"	"	"	"	9169.6	14989.1	"
1942-43	"	"	"	"	"	"	8209.8	"	"	"	"	9898.5	16451.7	"
1943-44	"	"	"	"	"	"	8315.5	"	"	"	"	"	"	"
1944-45	"	"	"	"	"	"	"	"	"	"	"	9659.4	"	"
1945-46	"	"	"	"	"	"	2066.6	447.0	287.5	236.3	1056.2	6833.8	15224.5	"
1946-47	"	"	"	"	"	"	2822.9	1978.1	1882.4	1934.3	2928.8	8604.0	15656.5	"
1947-48	"	"	"	"	"	"	2352.9	1543.8	1453.0	1306.7	1983.7	7355.9	15197.5	"
1948-49	"	"	"	"	"	"	8315.5	4297.9	4119.8	4392.1	4992.0	9898.5	16451.7	"
1949-50	"	"	"	"	"	"	3015.7	2141.8	2031.4	1976.4	2697.4	7252.7	13740.8	"
1950-51	"	"	"	"	"	"	3603.6	2953.3	2707.7	2835.9	3671.9	8738.8	15940.6	"
1951-52	"	"	"	"	"	"	4888.8	4016.1	3697.8	3716.9	4505.2	9798.1	16271.8	"
1952-53	"	"	"	"	"	"	6496.0	4274.0	4031.0	4289.9	4857.7	9045.1	16098.4	"
1953-54	"	"	"	"	"	"	2066.6	162.2	12.5	25.9	744.7	6037.2	13632.2	"
1954-55	"	"	"	"	"	"	3891.1	3289.5	3317.3	3257.4	4074.3	7985.5	14045.2	"
1955-56	"	"	"	"	"	"	2150.6	1280.1	1155.3	1093.9	1898.6	7844.8	15385.9	"
1956-57	"	"	"	"	"	"	2689.5	1861.1	1800.9	1746.9	2591.7	7825.9	16451.7	"
1957-58	"	"	"	"	"	"	2156.2	965.7	985.0	1143.3	2140.5	7500.1	15744.1	"

TABLE 11M
(Metric Units)
COMPOSITE END STORAGE
FOR THE WHOLE OF CANADIAN STORAGE
END OF PERIOD TREATY STORAGE CONTENTS (hm^3)
2017 - 18 ASSURED OPERATING PLAN

YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	19119.2	19119.2	18348.3	17710.2	16266.7	13301.9	8315.5	4180.0	3182.8	2932.0	3057.5	6719.3	15186.8	18716.0
1929-30	19103.8	18827.8	16455.8	14145.5	11170.2	8219.8	2986.6	500.6	0.0	289.4	1760.3	6319.8	13225.6	17449.6
1930-31	18369.3	18583.4	17245.3	15154.5	11935.2	8111.5	3730.6	798.3	0.0	11.7	0.2	3912.6	10437.9	12690.8
1931-32	12118.5	11533.0	9672.6	7618.2	3890.8	620.7	0.0	0.0	4.2	297.5	1127.4	5836.1	14248.8	18630.4
1932-33	18952.3	19119.2	16972.3	15540.1	15595.9	12631.6	7470.7	3438.7	1231.1	1072.8	1581.0	5862.3	13998.0	18891.7
1933-34	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	7657.1	3784.2	1883.4	1482.9	3003.7	8099.0	15197.3	18631.3
1934-35	19016.2	18818.8	16577.9	15038.8	15906.6	12631.6	7495.2	3824.8	3001.7	2701.3	3045.5	7572.5	14860.4	19119.2
1935-36	19119.2	19067.3	18099.9	16287.0	13851.9	10186.4	4848.4	2202.4	1236.8	1020.7	2139.3	8732.2	16220.2	18891.7
1936-37	19071.7	18815.3	16577.9	14434.2	11445.9	7957.1	2923.2	453.1	0.0	21.3	128.9	3781.0	11126.4	14629.9
1937-38	14611.1	14278.4	12558.6	11014.1	9506.3	7518.6	4450.6	3544.4	1910.3	1663.4	1438.4	6317.9	14083.1	18829.5
1938-39	18773.5	18693.5	17256.4	16171.8	13944.6	11437.9	6178.9	4235.6	3302.4	3381.2	3463.9	9898.5	14763.0	18891.7
1939-40	19104.5	18848.6	16720.3	15491.4	14153.1	12631.6	7434.7	3738.9	3114.5	3332.0	4101.0	9898.5	14809.0	17703.6
1940-41	17922.1	17730.3	16577.9	16398.3	13969.4	10912.3	6981.1	3783.4	3186.5	3716.9	4747.4	7497.1	11742.5	13981.3
1941-42	13600.9	13266.0	12417.5	13554.2	12482.6	12631.6	8033.2	4297.9	2670.7	2389.8	2151.8	6810.6	12585.3	18568.7
1942-43	19033.3	19012.5	17346.9	15707.2	15114.4	12631.6	8227.9	4297.9	3266.5	3441.9	3533.1	6867.6	12747.0	18891.7
1943-44	19119.2	19119.2	18182.6	17421.3	15910.7	12629.8	8275.9	4208.4	2955.7	2826.6	2872.8	5892.9	11185.6	13066.1
1944-45	12696.9	12198.5	10419.1	8949.2	5782.8	2472.8	499.4	0.0	0.0	2.0	0.0	4475.8	11735.1	15720.4
1945-46	15301.3	14843.3	13043.3	11391.4	9378.3	7277.4	2066.6	447.0	0.0	0.0	692.4	6678.7	15169.4	18891.7
1946-47	19119.2	19081.8	18348.3	17421.3	16191.1	12631.6	7268.4	3242.5	1882.4	1934.3	2928.8	8604.0	15656.5	19119.2
1947-48	19119.2	19062.9	18348.3	17421.3	16191.1	12631.6	7333.2	3089.6	1453.0	1193.7	1687.9	7355.9	15197.5	19119.2
1948-49	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	8315.5	4297.9	3335.0	3334.2	3683.8	9898.5	15594.1	18136.6
1949-50	18877.7	18776.2	16725.9	15475.5	15657.0	12631.6	7264.2	3197.0	2024.8	1875.1	2044.6	5509.7	13740.8	19119.2
1950-51	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	7465.1	3523.3	2440.2	2496.0	2832.7	8734.6	15155.0	18969.2
1951-52	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	7266.9	4016.1	2946.4	2785.2	3569.1	9372.4	16008.6	18891.7
1952-53	19119.2	19034.3	17637.1	15978.5	13558.1	10430.3	6655.2	4274.0	3254.0	2865.0	2435.8	7028.6	14251.0	18891.7
1953-54	19096.0	19119.2	18348.3	17421.3	16191.1	12631.6	7412.0	3521.6	1355.4	526.5	606.0	6037.2	13632.2	19119.2
1954-55	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	7529.2	3584.0	2613.9	2532.2	2235.2	5069.1	14045.2	18891.7
1955-56	19119.2	19119.2	18348.3	17421.3	16191.1	12631.6	7396.1	3176.4	1155.3	1074.5	1898.6	7844.8	15385.9	18891.7
1956-57	19033.3	19119.2	18348.3	17421.3	16191.1	12631.6	7316.3	3275.8	1800.9	1722.2	2175.0	7825.9	16421.6	18891.7
1957-58	19009.1	18804.3	16940.7	16178.9	14835.2	12631.6	7388.2	3474.7	1205.9	1143.3	1606.7	7500.1	15744.1	18891.7
Max	19119.2	19119.2	18348.3	17710.2	16266.7	13301.9	8315.5	4297.9	3335.0	3716.9	4747.4	9898.5	16421.6	19119.2
Median	19083.8	19023.4	17301.6	16175.3	15355.1	12631.6	7324.8	3522.5	1896.8	1798.6	2163.4	6948.1	14507.0	18891.7
Average	18104.1	17986.2	16642.0	15462.4	13875.6	10860.4	6206.2	3013.6	1880.5	1802.2	2218.3	7065.1	14138.5	17970.9
Min	12118.5	11533.0	9672.6	7618.2	3890.8	620.7	0.0	0.0	0.0	0.0	0.0	3781.0	10437.9	12690.8

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

	2010-11	2011-12 through 2013-14 1/	2014-15	2015-16 through 2016-17 3/	2017-18
MICA TARGET OPERATION (hm^3 or m^3/s)					
AUG 15	8414.3	8230.9	8267.6	8267.6	8548.7
AUG 31	FULL	FULL	FULL	FULL	FULL
SEP	FULL	FULL	FULL	FULL	FULL
OCT	8387.9	8387.9	8387.9	8328.5	8328.5
NOV	594.7	594.7	623.0	594.7	538.0
DEC	707.9	707.9	623.0	481.4	651.3
JAN	764.6	679.6	679.6	679.6	679.6
FEB	594.7	594.7	594.7	736.2	651.3
MAR	594.7	481.4	707.9	707.9	283.2
APR 15	623.0	566.3	481.4	594.7	424.8
APR 30	283.2	283.2	283.2	283.2	283.2
MAY	226.5	226.5	226.5	226.5	226.5
JUN	226.5	226.5	283.2	226.5	226.5
JUL	8482.9	8482.9	8482.9	8407.0	8407.0
COMPOSITE CRC1 CANADIAN TREATY STORAGE CONTENT (hm3)					
1928 AUG 31	19069.0	19118.7	19119.2	19119.2	19119.2
1928 DEC	12443.4	12732.1	12923.2	12459.3	13301.9
1929 APR15	2564.5	2653.1	2637.9	2506.5	2932.0
1929 JUL	17696.7	17933.1	18351.7	18559.7	18716.0
COMPOSITE CANADIAN TREATY STORAGE CONTENT (hm3)					
Pre AOP15: 60-Yr Avg, AOP15 -17: 70-Yr Avg 2/					
AUG 31	18197.7	18013.8	18121.4	18142.3	18070.3
DEC	11286.0	11327.8	11363.5	10985.5	11069.5
APR15	2061.6	2222.9	2175.9	1752.5	1984.2
JUL	17784.1	17486.1	17811.0	17869.5	18077.2
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)					
U.S. Firm Energy	-0.3	0.1	0.0	0.0	0.0
U.S. Dependable Peaking Capacity	-19.1	-22.9	-3.9	-2.1	6.9
U.S. Average Annual Usable Secondary Energy	16.0	21.6	21.3	17.6	22.7
BCH Firm Energy	34.4	43.6	44.0	24.0	18.6
BCH Dependable Peaking Capacity	43.8	41.7	47.8	28.2	37.2
BCH Average Annual Usable Secondary Energy	-20.8	-13.9	-33.4	-16.2	-24.1
COORDINATED HYDRO MODEL LOAD (MW)					
AUG 15	11138	10969	11187	11367	12028
AUG 31	11167	11104	10971	10944	11399
SEP	11025	11081	9756	9822	10207
OCT	9958	9920	9758	10051	9233
NOV	11333	11458	11821	12152	11434
DEC	13369	13316	13836	13744	13523
JAN	13076	12878	13323	13933	13862
FEB	11902	11721	13179	12876	13006
MAR	10967	10501	12022	11269	11264
APR 15	10241	9786	10476	10894	9583
APR 30	12475	11502	11012	11600	10684
MAY	13493	13287	12198	12166	12344
JUN	14080	13867	12208	11291	11314
JUL	12725	12531	11954	11812	12256
ANNUAL AVERAGE	12039	11856	11819	11794	11689

1/ The AOP 2013-14 and 2012-13 utilize the same system regulation study as the 2011-12.

2/ Prior to AOP15, average content based on 60 years of modified flows. AOP15 through AOP17 averages based on 70 years of modified flows. AOP18 averages based on 80 years of modified flows.

3/ The AOP 2016-17 utilizes the same Step 1 system regulation studies as used in the AOP 2015-16, so these coordinated hydro loads will be used for the DOP17 TSR unless otherwise agreed.

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

Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Canadian Projects					
Mica (1890)	Minimum Flow	3000 cfs	85.0 m^3/s		In place in AOP79, AOP80, AOP84.
Arrow (1831)	Minimum Flow	5000 cfs	141.6 m^3/s		In place in AOP79, AOP80, AOP84.
	Draft Rate Limit	1.0 ft/day	0.30 m/day		
Duncan (1681)	Minimum Flow	100 cfs	2.8 m^3/s		In place in AOP79, AOP80, AOP84.
	Maximum Flow	10000 cfs	283.2 m^3/s		
	Draft Rate Limit	1.0 ft/day	0.30 m/day		
	Other			Remove 5-step logic of Operate to meet IJC orders for Corra Linn.	CRTOC agreement on to remove 5-step logic procedures to implement 1938 IJC order. 2012
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	9500 cfs	269.0 m^3/s	Step 1 only	
	Minimum Content			None	
	Other			No VECC limit.	VECC limit not in place in AOP79.
Kerr (1510)	Minimum Flow	1500 cfs	42.5 m^3/s	All periods	In place in AOP80, AOP84.
	Maximum Flow			None	
	Minimum Content	614.7 ksfd	1503.9 hm^3	Jun - Sep	MPC 2-1-92, PNCA submittal similar operation, Jun-Aug 15, in AOP80.
		2893.0 ft	881.79 m		
		426.3 ksfd	1043 hm^3	May	
		2890.0 ft	880.9 m		
		0.0 ksfd	0 hm^3	Empty Apr 15	FERC, AOP80.
		2883.0 ft	878.74 m		
	Maximum Content	58.6 ksfd 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	0 hm^3	Conditions permitted, should be on or about, empty Mar and Apr 15.	FERC, AOP80.
		2883.0 ft	878.74 m		
Thompson Falls (1490)				None Noted	

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Project Name (Number)	Constraint Type	Requirements English	Metric	Explanation	Source
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 (empty at end of	
		2051.0 ft	625.14 m		
		190.4 ksfd	465.83 hm^3	Apr 30	
		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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Project Name (Number)	Constraint Type	Requirements English	Metric	Explanation	Source
Albeni Falls (1465) (Continued)	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 1208.0 ft	0.0 hm^3 368.20 m	Empty at end of CP.	
	Step I only:	843.7 ksfd 1240.0 ft	2064.2 hm^3 377.95 m	May and June	Retain as a power operation (for pumping).
	Steps II & III only:	868.8 ksfd 1240.0 ft	2125.6 hm^3 378.0 m	May and June	
	Maximum Content Step I only:	2.0 ft 3.0 ft	0.61 m 0.91 m	Operating room Sep - Nov Operating room Dec - Feb	In place in AOP89 Retain as a power operation.
	Steps II & III only:	2557.1 ksfd 1288.0 ft	6256.1 hm^3 392.58 m	Aug-Nov	
		2518.3 ksfd 1287.0 ft	6161.2 hm^3 392.28 m	Dec-Feb	
	Draft Rate Limit	1.3 ft/day 1.5 ft/day	0.40 m/day 0.46 m/day	(bank sloughage) (Constraint submitted as 1.5 ft/day interpreted as 1.3 ft/day mo.ave.)	
Chief Joseph (1270)	Other Spill	500 cfs	14.2 m^3/s	All periods	
Wells (1220)	Other Spill	1000 cfs	28.3 m^3/s	All periods	2/1/05 C. Wagers, Douglas With fish ladder
	Fish Spill			None	
Rocky Reach (1200)	Fish Spill/Bypass			None	
	Other Spill	200 cfs	5.7 m^3/s	Aug 31 - Apr 15 (leakage)	
Rock Island (1170)	Fish Spill/Bypass			None	
Wanapum (1165)	Fish Spill/Bypass			None	
	Other Spill	2200 cfs	62.3 m^3/s	All periods	With fish ladder

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Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
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	0 cfs	0.0 m^3/s	All years, all periods in CP & LT studies.	4-04 C. Henriksen
	Downstream Minimum Flow	6500 cfs	184.1 m^3/s	All periods for navigation requirement downstream at Hells Canyon (project #762). Draft Brownlee to help meet this requirement in CP and LT studies.	
	Power Operation			Agree to use similar “historic” power operation (rule curves) provided by IPC and used in AOP since AOP97 for CP.	2-1-91 PNCA submittal
				Optimizer was used in the Step I critical period study to get a starting point for Brownlee operations. Results were then modified to follow the general shape of the "historic" shape for power with the exception of going empy at the end of the critical period. To the extent possible, CRC1 is used in every year. Step II/III studies will use the same operation, except as needed to start critical periods full and end empty.	5-12 P. Kingsbury, T. Downen (BPA)
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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Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
John Day (440) (Continued)	Other				
	Step I:	269.7 ksfd	659.8 hm^3	June - Aug 15	In place AOP80
		268.0 ft	81.69 m		
		242.5 ksfd	593.3 hm^3	Aug 31 - Sep	
		267.0 ft	81.38 m		
		153.7 ksfd	376.0 hm^3	Oct - Mar	
		263.6 ft	80.35 m		
		114.9 ksfd	281.1 hm^3	Apr - May	
		262.0 ft	79.86 m		
	Steps II & III:	190.0 ksfd	464.8 hm^3	Use JDA as run-of-river plant.	
		265.0 ft	80.77 m		
The Dalles (365)	Fish Spill/Bypass			None	
	Other Spill	1300 cfs	36.8 m^3/s	All periods	
	Incremental Spill			None	
	Minimum Flow	50000 cfs	1415.8 m^3/s	Mar - Nov	
		12500 cfs	354.0 m^3/s	Dec - Feb	
Bonneville (320)	Fish Spill/Bypass			None	
	Other Spill	8040 cfs	227.7 m^3/s	All periods	
	Incremental Spill			None	
Kootenay Lake (Corra Linn (1665))	Minimum Flow	5000 cfs	141.6 m^3/s	All periods	BCHydro agreements 1969.
	Other			Remove 5-step logic of Operate to meet IJC orders for Corra Linn.	CRTOC agreement on to remove 5-step logic procedures to implement 1938 IJC order.
Chelan (1210)	Minimum Flow	50 cfs	1.4 m^3/s	All periods	In place in AOP79, AOP80, AOP84
	Minimum Content	308.5 ksfd	126.1 hm^3	Jul - Sep (except as needed to empty at end of critical period).	In place in AOP79, AOP80, AOP84
		1098.0 ft	334.7 m		
Couer d'Alene L (1341)	Minimum Flow	50 cfs	1.4 m^3/s	All periods	In place in AOP79.
	Minimum Content	112.5 ksfd	275.2 hm^3	May - Aug	
		2128.0 ft	648.6 m	Flood control may override these minimum contents.	2-1-00 PNCA submittal
Post Falls (1340)	Minimum Flow	50 cfs	1.4 m^3/s	All periods	In place in AOP79, AOP80, AOP84.
Other Major Step I Projects					
Libby (1760)	Minimum Flow	4000 cfs	113.3 m^3/s	All periods	
	Other Spill	200 cfs	5.7 m^3/s	All periods	

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Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Libby (1760) (Continued)	Minimum Content	By			
		776.9 ksfd	1900.7 hm^3	1929 Dec	2-1-93 PNCA submittal, in plac in AOP99.
		2363.0 ft	720.24 m		
		676.5 ksfd	1655.1 hm^3	1929 Jan	
		2355.0 ft	717.80 m		
		603.6 ksfd	1476.8 hm^3	1929 Feb	
		2349.0 ft	715.98 m		
		2147.7 ksfd	5254.5 hm^3	1929 Jul	
		2443.0 ft	744.63 m		
		652.0 ksfd	1595.2 hm^3	1930 Dec	
		2353.0 ft	717.19 m		
		433.2 ksfd	1059.9 hm^3	1930 Jan	
		2334.0 ft	711.40 m		
		389.3 ksfd	952.5 hm^3	1930 Feb	
		2330.0 ft	710.18 m		
		348.5 ksfd	852.6 hm^3	1930 Mar	
		2326.0 ft	708.96 m		
		297.4 ksfd	727.6 hm^3	1930 Apr 15	
		2321.0 ft	707.44 m		
		444.2 ksfd	1086.8 hm^3	1930 Apr 30	
		2335.0 ft	711.71 m		
		499.1 ksfd	1221.1 hm^3	1930 May	
		2340.0 ft	713.23 m		
		1344.6 ksfd	3289.7 hm^3	1930 Jun	
		2402.0 ft	732.13 m		
		1771.9 ksfd	4335.1 hm^3	1930 Jul	
		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		
		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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Project Name (Number)	Constraint Type	Requirements English	Metric	Explanation	Source
Libby (1760) (Continued)	Max Summer Draft	5 ft	1.5 m		
	Other			Remove 5-step logic of Operate to meet IJC orders for Corra Linn.	CRTOC agreement on to remove 5-step logic procedures to implement 1938 IJC order. 2012
Dworshak (535)	Minimum Flow	1600 cfs	45.3 m^3/s	All periods	2-1-12 PNCA submittal (1500 cfs powerhouse/100 cfs hatchery water supply)
	Maximum Flow	14000 cfs	396.4 m^3/s	All periods (model includes maximum 14000 cfs for all periods, but URC may override.)	2-1-02 PNCA submittal
		25000 cfs	707.9 m^3/s	Up to 25 kcfs for flood control all periods.	
	Start CP at:	497 ksfd	1215.9 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:				Target Elev based on 2010 modified flows and new 80 yr Flood Control data
		780.9 ksfd	1910.5 hm^3	Jul	
		1573.4 ft	479.57 m		
		652.6 ksfd	1596.6 hm^3	Aug 15	for Jul-Aug 15 and Sep based
		1556.8 ft	474.51 m		use 80-yr Median May 2012
		497 ksfd	1215.9 hm^3	Aug 31	
		1535 ft	467.87 m		
		389.4 ksfd	952.7 hm^3	Sep	
		1519 ft	462.99 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	450 cfs	12.7 m^3/s	Jul	2-1-09 PNCA submittal
		510 cfs	14.4 m^3/s	15-Aug	
		470 cfs	13.3 m^3/s	30-Aug	
		480 cfs	13.6 m^3/s	Sep	
		530 cfs	15.0 m^3/s	Oct	
		410 cfs	11.6 m^3/s	Nov	
		340 cfs	9.6 m^3/s	Dec	
		100 cfs	2.8 m^3/s	Jan	
		130 cfs	3.7 m^3/s	Feb	
		230 cfs	6.5 m^3/s	Mar	
		420 cfs	11.9 m^3/s	15-Apr	
		440 cfs	12.5 m^3/s	Apr 30 - May	
		460 cfs	13.0 m^3/s	Jun	

Appendix A
Project Operating Procedures for the 2017-18
Assured Operating Plan and Determination of Downstream Power Benefits

Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Lower Granite (520) (Continued)	Incremental Spill			Removed	
	Fish Spill	17333 cfs	490.8 m^3/s	Apr 15 [20 kcfs for 13 days]	2-1-12 PNCA submittal
		20000 cfs	566.3 m^3/s	Apr 30 - May [20 kcfs]	2-1-12 PNCA submittal
		19333 cfs	547.4 m^3/s	June [20 kcfs through June 21 then 18 kcfs]	2-1-12 PNCA submittal
		18000 cfs	509.7 m^3/s	Jul - Aug	2-1-12 PNCA submittal
	Maximum Fish Spill	40000 cfs	1132.7 m^3/s	Apr 15 - Jun 21	
		40000 cfs	1132.7 m^3/s	Jun - Aug 15	
	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 ft	223.42 m	On MOP Apr - Oct 31.	
		245.7 ksfd	601.1 hm^3	On full pool Nov 30 - Mar 31.	
		738 ft	224.94 m	On full pool Nov 30 - Mar 31.	
Little Goose (518)	Bypass Date			None	
	Other Spill	590 cfs	16.7 m^3/s	Jul	2-1-09 PNCA submittal
		620 cfs	17.6 m^3/s	15-Aug	
		500 cfs	14.2 m^3/s	30-Aug	
		750 cfs	21.2 m^3/s	Sep	
		640 cfs	18.1 m^3/s	Oct	
		500 cfs	14.2 m^3/s	Nov	
		460 cfs	13.0 m^3/s	Dec	
		120 cfs	3.4 m^3/s	Jan	
		240 cfs	6.8 m^3/s	Feb	
		380 cfs	10.8 m^3/s	Mar	
		530 cfs	15.0 m^3/s	15-Apr	
		580 cfs	16.4 m^3/s	Apr 30 - May	
		660 cfs	18.7 m^3/s	May	
		590 cfs	16.7 m^3/s	Jun	
	Incremental Spill			Removed	
	Fish Spill (% of outflow)	26%		Apr 15 [30%*13/15]	2012 data submittal
		30%		Apr 30	2012 data submittal
		30%		May	2012 data submittal
		30%		Jun - Aug 31	2012 data submittal
	Maximum Fish Spill	30000 cfs	849.5 m^3/s	Apr 15 - Apr 31	
		28000 cfs	792.9 m^3/s	May	
		30000 cfs	849.5 m^3/s	Jun	
		28000 cfs	792.9 m^3/s	Jul - Aug 31	
	Minimum Flow	11500 cfs	325.6 m^3/s	All periods	
	Other	260.5 ksfd	106.5 hm^3	On MOP Apr - Aug 31.	
		633 ft	192.94 m		
		285.0 ksfd	697.3 hm^3	On full pool Sep 30 - Mar 31.	
		638 ft	194.46 m		

Appendix A
Project Operating Procedures for the 2017-18
Assured Operating Plan and Determination of Downstream Power Benefits

Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Lower Monumental (504)	Bypass Date			A bypass date of 2010 was assumed.	
	Other Spill	790 cfs	22.4 m^3/s	Jul	2-1-09 PNCA submittal
		860 cfs	24.4 m^3/s	15-Aug	
		770 cfs	21.8 m^3/s	30-Aug	
		780 cfs	22.1 m^3/s	Sep	
		840 cfs	23.8 m^3/s	Oct	
		750 cfs	21.2 m^3/s	Nov	
		720 cfs	20.4 m^3/s	Dec	
		450 cfs	12.7 m^3/s	Jan	
		410 cfs	11.6 m^3/s	Feb	
		560 cfs	15.9 m^3/s	Mar	
		770 cfs	21.8 m^3/s	15-Apr	
		780 cfs	22.1 m^3/s	Apr 30 - May	
		840 cfs	23.8 m^3/s	May	
		780 cfs	22.1 m^3/s	Jun	
	Fish Spill	22533 cfs	638.1 m^3/s	Apr 15 [26000*(13/15)]	2-1-12 PNCA submittal
		25000 cfs	707.9 m^3/s	Apr 31	
		22000 cfs	623.0 m^3/s	May	2012 data submittial
		18333 cfs	519.1 m^3/s	June	2012 data submittial
		17000 cfs	481.4 m^3/s	Jul - Aug 31	
	Maximum Fish Spill	26000 cfs	736.2 m^3/s	Apr 15	
		25000 cfs	707.9 m^3/s	Apr 30	
		22000 cfs	623.0 m^3/s	May	
		19000 cfs	538.0 m^3/s	Jun	
		24000 cfs	679.6 m^3/s	Jul - Aug 31	
	Minimum Flow	11500 cfs	325.6 m^3/s	All period	
	Other	180.5 ksfd 537 ft	441.6 hm^3 163.68 m	On MOP Apr - Aug 31.	
		190.1 ksfd 540 ft	465.1 hm^3 164.59 m	On full pool Sep 30 - Mar 31.	
Cushman (2206)	Other Spill	240 cfs	6.8 m^3/s	All periods	2-1-09 PNCA submittal
LaGrande (2188)	Other Spill	30 cfs	0.8 m^3/s	All periods	Submittal
Lower Baker (2025)	Max Storage Limits	67.0 ksfd 442.4 ft	163.9 hm^3 134.84 m	Jul - Aug 31	2-1-12 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	
	Min Storage Limit	30.4 ksfd 404.8 ft	74.4 hm^3 123.38 m	Jun - Sep	
		18.0 ksfd 389.0 ft	44.0 hm^3 118.57 m	Oct - May	

Appendix A
Project Operating Procedures for the 2017-18
Assured Operating Plan and Determination of Downstream Power Benefits

Project Name (Number)	Constraint Type	Requirements English	Requirements Metric	Explanation	Source
Upper Baker (2028)	Max Storage Limits	107.4 ksfd	262.8 hm^3	May - Sep	2-1-12 PNCA submittal
		727.8 ft	221.83 m		
		103.5 ksfd	253.2 hm^3	Oct	
		726.1 ft	221.32 m		
		70.9 ksfd	173.5 hm^3	Nov - Feb	
		711.7 ft	216.93 m		
		84.6 ksfd	207.0 hm^3	Mar - Apr 30	
		718.0 ft	218.85 m		
	Min Storage Limits	100.5 ksfd	245.9 hm^3	Jun - Aug 31	
		724.8 ft	220.92 m		
		91.1 ksfd	222.9 hm^3	Sep	
		720.8 ft	219.70 m		
		40.6 ksfd	99.3 hm^3	Oct	
		695.2 ft	211.90 m		
		25.5 ksfd	62.4 hm^3	Nov - Apr 30	
		685.0 ft	208.79 m		
Timothy (117)	Minimum Content	24.5 ksfd	59.9 hm^3	Oct - May	3-6-01 PNCA submittal
		3180.0 ft	969.26 m		
		31.1 ksfd	76.1 hm^3	Jun - Aug 31	
		3190.0 ft	972.31 m		
		27.8 ksfd	68.0 hm^3	Sep	
		3185.0 ft	970.79 m		
Long Lake (1305)	Minimum Content	50.1 ksfd	122.6 hm^3	Apr - Nov	2-5-02 PNCA submittal
		1535.0 ft	467.87 m		
		19.7 ksfd	48.2 hm^3	Dec - Mar	
		1522.0 ft	463.9 m		
	Draft Rate Limit	1.0 ft/day	0.30 m/day		2-1-03 PNCA submittal
Priest Lake (1470)	Maximum Content	0.0 ksfd	0.0 hm^3	Oct	2-1-03 PNCA submittal
		0.0 ft	0.00 m		
	Max/Min Content	35.5 ksfd	86.9 hm^3	Maintain at or near after runoff through Sep.	
		3.0 ft	0.91 m		
Ross (2070)	Minimum Content/			Dependent on Skagit Fisheries.	2-1-06 PNCA submittal
		Fixed ARCs and VRCs			Data came from SCL based on the 80-yr modified streamflow. April 2012
Gorge (2065)	Minimum Flow			Settlement; monthly data, varies by water year.	2-1-12 PNCA submittal

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 2017-18

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DETERMINATION OF DOWNSTREAM POWER BENEFITS (DDPB) FOR THE ASSURED OPERATING PLAN FOR OPERATING YEAR 2017-18

April 2013

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 2017-18 (DDPB18).

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 September 2011 update to Appendix 1 - Refill Curves; the November 2004 additions of Appendix 6 - Streamline Procedures, and Appendix 7 - Table of Median Stream flows; and in Appendix 8, the September 2007 addition of Appendix 8 concerning Water Supply Forecasts and the February 2012 revision of Summary of Errors and Hedges in Table 1.

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 the DDPB18, the Entities have agreed to use only the first of the three streamline procedures defined in Appendix 6 of the POP. This consists of "Forecasting Loads and Resources" for determining the thermal installations (described in Subsection 7(d) of the AOP18 document).

In addition to the changes discussed in Subsection 2(a) of the AOP18 document, the Entities have agreed to modify the DDPB18 Table 2 calculation of Thermal Displacement Market (TDM), as was done since DDPB13, to use thermal imports (e.g. market purchases of power from California, but 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.

The Canadian Entitlement Benefits were computed from the following studies:

Step I -- Operation of the total United States of America (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; and

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 2017-18 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 Joint Optimum results in Table 5):

Dependable Capacity	= 1304.1 megawatts (MW)
Average Annual Usable Energy	= 475.0 average annual MW

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

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."*

Step II studies based on the assumption of optimum power generation in Canada and the USA resulted in a 1.3 average annual megawatt (aMW) increase in the Energy Entitlement and a 1.3 MW increase in the Capacity Entitlement compared to the Step II study based on optimum power generation only in the USA (see Table 5, columns A and B). Since there was no reduction in the downstream power benefits for the Joint Optimum Study, the computation of the maximum allowable reduction in downstream power benefits, as defined in Section 3.3.A(3) of the POP, was not necessary.

5. Delivery of the Canadian Entitlement

See Section 6 of the AOP18.

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 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 Procedures noted in Section 2 of this DDPB and described in Section 7 of the AOP18. Table 1A shows the Step I energy loads and resources while Table 1B shows the Step I peak loads and resources.

Table 2 Determination of Thermal Displacement Market

This table shows the computation of the TDM for the downstream power benefit determination of average annual usable energy. The TDM is the thermal installations shown in Table 1A with subsequent reductions for estimated minimum thermal generation and system sales. System sales are all exports except for Canadian Entitlement, plant sales, seasonal exchanges, and flow-through-transfers, as defined in POP and modified in Section 2 of this DDPB.

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) 2011 White Book (WB11) load forecast as described in Subsection 7(a) of the AOP18. The Grand Coulee net 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 to 3.

Hydro maintenance, transmission losses and peaking reserves (for capacity balance) are summed together in the Step I load-resource balance as a resource adjustment. The Steps II and III capacity balance includes the hydro maintenance and the peaking reserves based on the same percentage as the Step I system.

The firm energy load carrying capability for the Steps I, II, and III Systems is based on the same critical periods as recent studies. The firm peak load carrying capability for each system is based on the period with the least surplus firm peak capability over the thirty water years. For the AOP/DDPB18, these periods are the first half of August 1932, January 1932, and January 1930 for the Steps I, II and III systems, respectively.

Table 5 Computation of Canadian Entitlement

A. Joint Optimum Generation in Canada and the USA
B. Optimum Generation in the USA Only
C. Optimum Generation in the USA and a 0.62 km^3 (0.5 Maf) reduction In Total Canadian Treaty Storage.

The essential elements used in the computation of the Canadian Entitlement arising from the downstream power benefits under the Joint

Optimum and USA Optimum are shown under Columns A and B, respectively. The elements for the computation of maximum allowable reduction in downstream benefits are shown in column C.

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 Joint Optimum Step II and the USA Optimum Step 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, as shown in Table 5, is equal to the firm hydro loads, 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 2016-17 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 2016-17 DDPB (DDPB17) 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 DDPB17. For DDPB18, the 2017-18 loads trend higher May through September and lower October through April compared to the 2016-17 loads. This is mainly due to the change in PNWA load shape, particularly March through September, and thermal maintenance schedules, which are explained in Subsection 7(b).

Differences between DDPB18 and DDPB17 Table 3 Hydro Loads (aMW)

	Aug1	*Aug2*	*Sept*	*Oct*	*Nov*	*Dec*	*Jan*	*Feb*	*Mar*	*15-Apr*	*30-Apr*	*May*	*June*	*July*	*Avg.*	*CPavg*
DDPB18 S2	8659	8641	7393	6738	8586	10414	10605	9686	8745	7494	8268	10534	9300	9431	*8999*	*8903*
DDPB17 S2	8098	8063	6875	6908	8958	10606	10770	9805	9218	8020	8923	9961	8608	9061	*8944*	*8948*
Difference	561	578	518	-170	-371	-192	-165	-119	-473	-526	-655	573	692	370	*55*	*-46*
DDPB18 S3	6288	6272	5188	4608	6214	7793	7965	7176	6435	5304	6058	8392	6986	6979	*6644*	*6957*
DDPB17 S3	5552	5522	4490	4522	6296	7707	7855	7022	6650	5582	6480	7582	6122	6426	*6354*	*6975*
Difference	735	750	699	86	-82	86	110	154	-215	-278	-422	810	864	554	*289*	*-17*

The average critical period load factor increased slightly from 74.03% in AOP17 (WB10) to 74.60% in AOP18 (WB11).

b) Thermal Installations

The total thermal installation energy capability shown in Tables 1 to 3 decreased by only 1 annual aMW compared to the DDPB17. This is due to the offsetting effects of reductions in PNWA firm load, exports and renewable resources (mostly wind) against decreases in imports and Step I hydro load (caused by changes in the PNWA load shape and WB thermal maintenance schedules).

Beginning with AOP06, Columbia Generating Station 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. Beginning with AOP/DDPB14 and continuing with this AOP/DDPB, the Entities have agreed to use the average of the two year maintenance schedule, thereby eliminating the year to year Energy Entitlement variability and reducing the effect on the AOP storage operations.

In addition, the thermal installation shape has changed due to changes in thermal maintenance schedules (mostly coal but also combustion turbines and co-generation).

The TDM increased by 42 annual aMW, due to changes in system sales. Both the thermal installation and TDM changes are shown in the following table.

DDPB18 minus DDPB17 Table 2 Thermal Installations and Thermal Displacement Market (aMW)

	Aug1	*Aug2*	*Sept*	*Oct*	*Nov*	*Dec*	*Jan*	*Feb*	*Mar*	*15-Apr*	*30-Apr*	*May*	*June*	*July*	*Avg.*	*CPavg*
DDPB18 T.I.	10381	10379	10305	10357	10461	10633	10593	10471	9797	10087	9476	6667	9276	10251	*9909*	*9994*
DDPB17 T.I.	10438	10437	10490	10462	10424	10503	10457	10459	9477	9730	8867	7362	9486	10124	*9911*	*9995*
Difference	-57	-58	-185	-105	37	130	136	12	320	358	608	-695	-210	128	*-1*	*-1*
TDM 18	9952	9951	9878	9929	10030	10198	10159	10040	9383	9666	9070	6323	8862	9824	*9491*	*9574*
TDM 17	9964	9964	10016	9988	9950	10028	9983	9985	9027	9274	8433	6957	9024	9656	*9448*	*9531*
Difference	-12	-13	-137	-59	80	170	176	55	355	392	637	-634	-162	168	*42*	*42*

c) Hydro Project Modified Stream Flows

The unregulated base stream flows used in the Steps II and III system regulation studies are the same as those used in the Step I studies (see Subsection 7(e) of AOP18), which were updated to the 2010 Modified Streamflows published by BPA in August 2011, except for adjustments to add the effect of natural lake regulation and remove reservoir evaporation at projects not included in Steps II or III.

d) Hydro Project Rule Curves

The critical rule curves and refill curves were updated in accordance with procedures defined in POP, except for the changes described in Subsection 7(f) of the AOP18. The Mica/Arrow operating criteria for the Step I study is also used in the Step II study.

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

Changes to operating procedures, constraints, and plant data are described in Subsection 7(g) of the AOP18.

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

The Entities conducted a full set of Step II (-42, -12, and -22) and Step III (-13) critical period and 30-year system regulation studies for the 2017-18 operating year in accordance with procedures described in Section 3.3 of the POP. The system regulation studies used version 29 (.net) of the HYDSIM model. The critical period studies establish the length of the critical stream flow period, the hydro firm load carrying capability, and critical rule curves.

The Step II and Step III critical stream flow periods are unchanged from the DDPB17 studies. The Step II critical period comprises the 20 calendar-months from 1 September 1943 through 30 April 1945, and the Step III critical period consists of the 5.5 calendar-months from 1 November 1936 through 15 April 1937. The Step II critical period generation, as compared to DDPB17, decreased by 45.6 aMW, while the average annual firm energy increased by 54.8 MW. The Step III critical period generation decreased by 17.4 aMW, but the average annual firm energy increased by 289.4 aMW. This is due to changes in the Steps II and III load shapes.

The Step II 30-year average generation, compared to DDPB17, increased by 21.0 aMW, and the Step III 30-year average generation decreased by 23.6 aMW, both due mainly to changes in storage operations caused by data updates as well as the above-mentioned changes in the hydro load shape.

g) Downstream Power Benefits

The Canadian Capacity Entitlement decreased from 1333.2 MW in the DDPB17 to 1304.1 MW in the DDPB18, a decrease of 29.1 MW. This is caused by a slight increase in the critical period load factor as well as a greater reduction in the Step II critical period generation relative to the Step III critical period generation.

The Canadian Energy Entitlement decreased from 484.0 annual aMW in the DDPB17 to 475.0 annual aMW in the DDPB18, a decrease of 9.0 annual aMW. This decrease is caused mainly by a combination of changes in the shape of the Thermal Displacement Market as well as the Steps II and III loads.

End Notes:

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

[2] The Step II DDPB18-42 30 year system regulation study dated 18 January 2013 and the Step III DDPB18-13 30-year system regulation study dated 4 January 2013 were used to determine the critical period and 30-year system generation.

TABLE 1A
DETERMINATION OF STEP I FIRM ENERGY HYDRO LOADS
FOR 2017-18 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/	23482	23491	21837	21038	23378	25825	25965	24734	22772	21609	21758	21205	22974	24411	23273	23349
b) Exclude 99% of UPL's Idaho load 3/	-520	-520	-471	-438	-431	-465	-437	-451	-424	-404	-405	-452	-574	-633	-475	-472
c) Update Coulee pumping 4/	-29	-61	-48	-9	-4	-9	5	-4	-14	-28	19	-34	-25	-70	-22	-21
d) …Total PNWA Firm Loads	**22934**	**22911**	**21317**	**20591**	**22943**	**25352**	**25533**	**24280**	**22334**	**21177**	**21373**	**20719**	**22375**	**23708**	**22776**	**22857**
e) Annual Load Shape in Percent	100.7	100.6	93.6	90.4	100.7	111.3	112.1	106.6	98.1	93.0	93.8	91.0	98.2	104.1	100.0	100.4
2. Flows-Out of firm power from PNWA																
a) White Book Exports, incl firm sp 5/	1499	1427	1330	1094	1092	998	1024	945	1129	1201	1259	1062	1354	1352	1174	1164
b) Remove WB Canadian Entitlement	-486	-486	-486	-486	-486	-486	-486	-486	-486	-486	-486	-486	-486	-486	-486	-486
c) Add est. Can. Entitle. Exported 6/	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469
d) Added export for WB surplus	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) Added SeEx for WB Surplus 7/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f) Added SeEx for AOP Hydro 7/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g) Imp. Thermal used out of region 8/	263	278	290	209	146	75	69	91	67	126	122	126	260	258	166	164
h) …Subtotal for Table 2	1746	1688	1603	1286	1221	1056	1076	1018	1179	1310	1365	1172	1597	1594	1322	1311
i) Remove Plant Sales	-685	-615	-536	-518	-535	-446	-472	-399	-618	-677	-731	-535	-743	-630	-566	-555
j) Remove Flow-through-transfer	-75	-75	-75	-45	-45	-45	-45	-40	0	0	0	0	0	0	-31	-34
k) …Total	**985**	**998**	**993**	**723**	**641**	**565**	**558**	**579**	**561**	**633**	**633**	**637**	**854**	**963**	**726**	**722**
3. Flows-In of firm power to PNWA, except from coordinated thermal installations																
a) White Book Imports 9/	-831	-816	-754	-809	-1076	-1255	-1167	-1124	-940	-812	-784	-693	-792	-866	-924	-938
b) Remove UP&L imports for 1(b) 3/	502	502	466	466	465	500	469	484	451	426	426	478	553	612	489	488
c) Remove Eastern Thermal Instal 10/	223	209	192	276	345	425	429	401	389	345	317	183	196	226	300	305
d) Added SeEx for WB Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) Added Can.Import for WB deficits 11/	-41	-194	0	0	0	-258	-414	-307	-285	0	0	0	0	-175	-130	-135
f) Added Calif.Import for WB deficits12/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g) Added Seas.Exch. for Aop hydro 7/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h) Remove Flow-Through-Xfers	75	75	75	45	45	45	45	40	0	0	0	0	0	0	31	34
i) …Total	**-72**	**-225**	**-21**	**-22**	**-221**	**-544**	**-638**	**-507**	**-384**	**-41**	**-41**	**-32**	**-42**	**-203**	**-233**	**-246**
4. PNWA Non-Step I Hydro and Non-Thermal Resources																
a) Hydro Independents (1929 water)	-1004	-987	-983	-1090	-1108	-1003	-1026	-847	-952	-1108	-1137	-1389	-1344	-1105	-1082	-961
b) Non-Step I Coordinated Hydro(1929)	-495	-458	-551	-925	-934	-945	-1245	-673	-715	-810	-705	-641	-1054	-658	-798	-808
c) WB Regional Hydro NUGs	-309	-307	-227	-149	-117	-109	-100	-105	-137	-265	-267	-389	-421	-404	-228	-216
d) WB Renewable NUGs	-55	-56	-56	-56	-56	-56	-56	-56	-55	-55	-55	-55	-55	-55	-56	-56
e) WB Renewables	-763	-1241	-1133	-1005	-845	-768	-542	-557	-946	-1281	-964	-1092	-1433	-1128	-967	-948
f) …Total (1929)	**-2625**	**-3049**	**-2950**	**-3224**	**-3059**	**-2881**	**-2969**	**-2239**	**-2805**	**-3519**	**-3128**	**-3565**	**-4307**	**-3350**	**-3130**	**-2988**
5. Step I System Load (1929) 13/	**21222**	**20635**	**19339**	**18069**	**20305**	**22491**	**22485**	**22114**	**19706**	**18250**	**18837**	**17759**	**18880**	**21118**	**20138**	**20344**
6. Coordinated Thermal Installations 14/																
a) Columbia Generation Station (WNP2)	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	715	515	947	954	965
b) Generic Thermal Installations	9351	9349	9275	9327	9431	9603	9563	9441	8767	9057	8446	5953	8761	9304	8956	9029
c) ...Total	**10381**	**10379**	**10305**	**10357**	**10461**	**10633**	**10593**	**10471**	**9797**	**10087**	**9476**	**6667**	**9276**	**10251**	**9909**	**9994**
7. Step I Hydro Resources (1929) 15/	**11533**	**10941**	**9656**	**8309**	**10500**	**12578**	**12617**	**12333**	**10550**	**8774**	**9979**	**11703**	**10260**	**11598**	**10891**	**11014**
8. Step I Resource Adjustments																
a) Hydro Maintenance	-32	-27	-9	-9	-4	0	0	0	-5	-7	-8	-20	-16	-51	-13	-12
b) Transmission System Losses 16/	-659	-658	-613	-588	-653	-720	-725	-690	-636	-604	-610	-591	-640	-680	-650	-652
9. Total Step I System Resources(1929)	**21222**	**20635**	**19339**	**18069**	**20305**	**22491**	**22485**	**22114**	**19706**	**18250**	**18837**	**17759**	**18880**	**21118**	**20138**	**20344**
10. Coordinated Hydro Load (1929) 17/	**12028**	**11399**	**10207**	**9233**	**11434**	**13523**	**13862**	**13006**	**11264**	**9583**	**10684**	**12344**	**11314**	**12256**	**11689**	**11822**
a) Coord. Hydro Load Shape (1929) 18/	102.9%	97.5%	87.3%	79.0%	97.8%	115.7%	118.6%	111.3%	96.4%	82.0%	91.4%	105.6%	96.8%	104.9%	100.0%	

Notes:

1/ The Step I critical period is the 42.5 months beginning 16 August 1928 and ending 29 February 1932.

2/ BPA Final 2011 White Book (WB11) total regional firm load estimate, which includes estimated Coulee pumping and Idaho loads served by Utah P&L.

3/ Annex B requires exclusion of Idaho load from area served by Utah Power Light in 1964. We exclude import that supports that, but include the import for the 1% within the region.

4/ Coulee pumping loads were updated to the 2012 PNCA data submittal to be consistent with the pumping flows in the Base Flows.

5/ WB11 exports include Firm Seasonal Exchanges, Flow-Through Transfers, Plant Sales, and an estimate of the Canadian Entitlement.

6/ Assumes 469 aMW Energy Entitlement exported to Canada.

7/ Seasonal Exchanges were not employed in this AOP, but lines 2(e) and 2(f) were retained for continuity.

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, determined to be about 28% of the estimated 469 aMW of Energy Entitlement .

12/ Added Calif. import as a portion of the resources needed to balance WB deficits, based on the pro-rata procedure.

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

14/ Thermal installations are CGS, plus a generic thermal installation that is sized to meet the Step 1 System load minus Step I Hydro.

15/ 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).

16/ Transmission losses are 2.71% of all resources including imports.

17/ The Coordinated Hydro Model Load is the Step I Hydro Resources plus Non-Step I Coordinated Hydro, lines 7 - 4(b).

18/ The Coordinated 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 2017-18 ASSURED OPERATING PLAN
(MW)

	Aug15	Aug31	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr15	Apr30	May	Jun	Jul
1. Pacific Northwest Area (PNWA) Firm Load														
a) White Book Regional Firm Load	31941	31941	28595	29256	32278	35790	35593	33728	30977	29235	29235	27911	30786	32973
b) Exclude 99% of UPL's Idaho load	-740	-740	-622	-563	-560	-641	-584	-583	-559	-531	-531	-572	-809	-884
c) Adj.for Federal Peak Diversity 1/	-488	-524	-553	-357	-305	-560	-312	-331	-388	-496	-512	-519	-521	-423
d) Updates to Coulee pumping forec.	-65	-65	-28	-76	126	126	251	-21	0	-18	-28	-2	-7	-72
e) ….Total PNWA Firm Loads	**30648**	**30612**	**27392**	**28260**	**31539**	**34715**	**34948**	**32794**	**30030**	**28190**	**28165**	**26818**	**29450**	**31593**
f) Monthly Load Factors in Percent	74.83	74.84	77.82	72.86	72.75	73.03	73.06	74.04	74.37	75.12	75.89	77.26	75.98	75.04
2. Flows-Out of firm power from PNWA														
a) White Book Exports	1998	1998	1998	1637	1601	1601	1601	1601	1556	1556	1563	1420	1923	1923
b) Remove WB Canadian Entitlement	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350	-1350
c) Add estimated Can.Entitle. exported	1303	1303	1303	1303	1303	1303	1303	1303	1303	1303	1303	1303	1303	1303
d) Added export for WB surplus	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) Add Seasonal Exch. WB Export	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f) Add Seasonal Exch. Shape Export	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g) Thermal Inst. used outside region 2/	256	255	277	151	117	10	0	77	54	85	66	126	259	245
h) …Subtotal for Table 2	*2207*	*2206*	*2228*	*1741*	*1671*	*1564*	*1554*	*1630*	*1562*	*1594*	*1583*	*1498*	*2135*	*2122*
i) Remove Plant Sales	-207	-207	-207	-207	-199	-199	-199	-199	-199	-199	-207	-63	-207	-207
j) Remove Flow-through-transfer	-75	-75	-75	-45	-45	-45	-45	-45	0	0	0	0	0	0
k) …Total	**1926**	**1925**	**1947**	**1489**	**1427**	**1320**	**1310**	**1387**	**1363**	**1395**	**1376**	**1436**	**1929**	**1915**
3. Flows-In of firm power to PNWA, except from coordinated thermal installations														
a) White Book Imports	-1086	-1086	-1022	-1125	-1450	-1625	-1637	-1605	-1244	-1107	-1107	-996	-1070	-1148
b) Remove UP&L imports for SW Idaho	544	544	500	501	507	530	500	514	478	453	453	528	633	670
c) Remove Eastern Thermal Instal	313	313	294	426	465	574	585	506	501	489	489	316	283	323
d) Added SeEx for WB Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e) Added Can.Import for WB deficits	-113	-1332	0	0	0	-1332	-1332	-1332	-1332	0	0	0	0	-1332
f) Added Calif.Import for WB deficits	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g) Added Seas.Exch. for Aop hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h) Remove Flow-Through-Xfers	75	75	75	45	45	45	45	45	0	0	0	0	0	0
i) …Total	**-267**	**-1486**	**-153**	**-153**	**-433**	**-1808**	**-1839**	**-1872**	**-1597**	**-165**	**-165**	**-152**	**-154**	**-1487**
4. PNWA Non-Step I Hydro and Non-thermal Resources														
a) Hydro Independents (1932)	-1431	-1330	-1275	-1226	-1330	-1432	-1590	-1301	-1678	-1716	-1732	-1963	-1864	-1569
b) Non-Step I Coord. Hydro (1932)	-1503	-1577	-1930	-2015	-2161	-2134	-2050	-1911	-1822	-1788	-2020	-2026	-2376	-2439
c) WB Regional Hydro NUGs	-374	-372	-301	-218	-159	-147	-138	-150	-186	-300	-309	-437	-457	-448
d) WB Renewable NUGs	-69	-69	-69	-69	-69	-69	-69	-69	-68	-68	-68	-68	-68	-68
e) WB Renewables	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31	-31
f) …. Total (1932)	**-3408**	**-3379**	**-3606**	**-3559**	**-3750**	**-3812**	**-3879**	**-3463**	**-3785**	**-3903**	**-4160**	**-4524**	**-4796**	**-4555**
5. Step I System Load 3/ (1932)	**28900**	**27671**	**25580**	**26038**	**28782**	**30415**	**30540**	**28846**	**26011**	**25518**	**25216**	**23577**	**26428**	**27466**
6. Coordinated Thermal Installations														
a) Columbia Generating Station (cgs)	1130	1130	1130	1130	1130	1130	1130	1130	1130	1130	1130	565	565	1130
b) Generic Thermal Installations	10938	10919	10978	11086	11180	11225	11237	11208	10659	11041	10676	8488	10410	10917
c) ...Total	**12068**	**12049**	**12108**	**12216**	**12310**	**12355**	**12367**	**12338**	**11789**	**12171**	**11806**	**9053**	**10975**	**12047**
7. Step I Hydro Resc. Needed (1932) 4/	**27020**	**25364**	**23074**	**22953**	**25428**	**26312**	**25931**	**24620**	**22423**	**21789**	**21670**	**22454**	**23778**	**25230**
8. Step I Resource Adjustments														
a) Hydro Maintenance 5/	-4595	-4032	-3787	-3208	-2935	-2037	-1561	-2286	-2626	-2751	-2483	-2360	-2202	-3720
b) ...Hydro maint. as % reg. hydro capa	*15.6%*	*13.7%*	*12.6%*	*10.7%*	*9.7%*	*6.7%*	*5.3%*	*8.2%*	*9.8%*	*10.0%*	*8.8%*	*8.2%*	*7.2%*	*12.1%*
c) Transmission System Losses 6/	-1162	-1217	-1201	-1227	-1260	-1331	-1332	-1256	-1198	-1184	-1202	-1161	-1272	-1299
d) Reserves (11% of resources) 7/	-4432	-4493	-4613	-4696	-4761	-4884	-4866	-4570	-4377	-4506	-4575	-4410	-4852	-4793
e) ....Peak reserves as % resources	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*	*11.0%*
f) ….Total Adjustments	**-10188**	**-9742**	**-9601**	**-9131**	**-8956**	**-8252**	**-7758**	**-8112**	**-8201**	**-8442**	**-8260**	**-7930**	**-8326**	**-9812**
9. Required Step I Resources	**28900**	**27671**	**25580**	**26038**	**28782**	**30415**	**30540**	**28846**	**26011**	**25518**	**25216**	**23577**	**26428**	**27466**
10. Coordinated Hydro load and Surplus/Deficit (1932)														
a) Coordinated Hydro Load (1932) 8/	28523	26941	25004	24968	27589	28445	27981	26532	24245	23576	23689	24479	26154	27670
b) Actual Coord. Hydro Gen (1932) 9/	29410	29446	30014	30124	30158	30269	29547	28034	26844	27645	28109	28870	30540	30686
c) ...Surplus/Deficit (1932)	887	2505	5010	5156	2569	1824	1566	1502	2599	4069	4420	4391	4386	3016

Notes:

1/ Federal peak diversity is a reduction in peak load due to peak loads not all being coincidental.
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 + 2k + 3i + 4f .
4/ Step I hydro resources needed to meet the load = line 5 minus lines 6c and 8f. Actual resource capability is higher. Used 1932 because has lowest surplus.
5/ From WB, based on 5-year PNCA average as a MW reduction from installed capacity.
6/ Transmission losses are 3.24% of all resources including imports, net of reserves and maintenance.
7/ Reserves assumed to be 11%.
8/ Lines 4b and 7.
9/ System Instantaneous Peak (1932).

TABLE 2
DETERMINATION OF THERMAL DISPLACEMENT MARKET
FOR 2017-18 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)	10381	10379	10305	10357	10461	10633	10593	10471	9797	10087	9476	6667	9276	10251	9909.4	9994.3
2. DISPLACEABLE THERMAL RESOURCES																
a) Minimum Gen. from % of Thermal	233	233	231	232	235	239	238	235	218	226	210	148	218	232	223.0	224.8
b) Net Displaceable Thermal Resources	**10148**	**10147**	**10074**	**10125**	**10226**	**10394**	**10355**	**10236**	**9579**	**9862**	**9265**	**6519**	**9058**	**10020**	**9686.4**	**9769.5**
3. SYSTEM SALES (i.e. Amount of Coordinated Thermal Installation Power Used Outside PNWA)																
a) Flows-Out (Table 1A, line 2(h))	1746	1688	1603	1286	1221	1056	1076	1018	1179	1310	1365	1172	1597	1594	1322.5	1311.2
b) ...Exclude Can.Entitlement Exported	-469	-469	-469	-469	-469	-469	-469	-469	-469	-469	-469	-469	-469	-469	-469.0	-469.0
c) ...Exclude Plant Sales	-685	-615	-536	-518	-535	-446	-472	-399	-618	-677	-731	-535	-743	-630	-566.1	-555.2
d) ...Exclude WB Flow-Through-Transfer	-75	-75	-75	-45	-45	-45	-45	-40	0	0	0	0	0	0	-30.8	-33.9
e) ...Exclude WB. Seasonal Exchange	-205	-205	-197	-15	0	0	0	0	0	0	0	0	-79	-189	-57.4	-56.1
f) ...Exclude SeEx for WB Surp/Def	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0.0
g) ...Exclude SeEx for AOP Hydro Diff.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0.0
h) ...Exclude Other Flow-ThruTransfer	-3	-3	-3	-3	-4	-4	-4	-4	-4	-3	-3	-3	-3	-3	-3.3	-3.4
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	309	322	324	237	168	92	85	107	88	161	161	165	303	302	195.9	193.6
k) Uniform Average Ann.System Sales	196	196	196	196	196	196	196	196	196	196	196	196	196	196	195.9	195.9
4 THERMAL DISPLACEMENT MARKET																
a) Line 2b minus line 3k	**9952**	**9951**	**9878**	**9929**	**10030**	**10198**	**10159**	**10040**	**9383**	**9666**	**9070**	**6323**	**8862**	**9824**	**9490.6**	**9573.6**

Notes:

2a Minimum generation is 0.0249 times the monthly 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 mostly wind farms that are exported to California; line 2(i), Table 1A.

3d Flow-through-transfers from the White Book.

3e Seasonal Exchanges from the White Book.

3f Seasonal exchange added to White Book value to export WB surplus.

3g Seasonal Exchanges were not employed in this AOP, but line 3 g) was retained for continuity.

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

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

3j Total System Sales are total exports excluding exchanges, plant sales, flow-thru-xfers, and the Canadian Entitlement. The sum of lines 3(a) through 3(i).

3k Average Annual System Sales shaped uniformly per 1988 Entity Agreement assumpting 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 2017-18 AOP/DDPB STUDIES

	PACIFIC NORTHWEST AREA LOADS				THERMAL INSTALLATIONS			
Period	Area Energy Load 1/ aMW	Annual Energy Load Shape Percent	Peak Load MW	Load Factor Percent	Energy Capability 2/ aMW	Annual Energy Shape Percent	Peak Capability MW	Capacity Factor Percent
August 1-15	22934	100.69	30648	74.83	10381	104.8%	12068	86.0%
August 16-31	22911	100.59	30612	74.84	10379	104.7%	12049	86.1%
September	21317	93.60	27392	77.82	10305	104.0%	12108	85.1%
October	20591	90.41	28260	72.86	10357	104.5%	12216	84.8%
November	22943	100.74	31539	72.75	10461	105.6%	12310	85.0%
December	25352	111.31	34715	73.03	10633	107.3%	12355	86.1%
January	25533	112.11	34948	73.06	10593	106.9%	12367	85.6%
February	24280	106.61	32794	74.04	10471	105.7%	12338	84.9%
March	22334	98.06	30030	74.37	9797	98.9%	11789	83.1%
April 1-15	21177	92.98	28190	75.12	10087	101.8%	12171	82.9%
April 16-30	21373	93.84	28165	75.89	9476	95.6%	11806	80.3%
May	20719	90.97	26818	77.26	6667	67.3%	9053	73.6%
June	22375	98.24	29450	75.98	9276	93.6%	10975	84.5%
July	23708	104.09	31593	75.04	10251	103.5%	12047	85.1%
Annual Avg. 7/	22775.6	100.00		74.71	9909.4	100.0%		83.8%
SI CP Avg(42.5mon)	22856.6			**74.60**	9994.3			
S2 CP Avg(20mon)	22847.7				10065.5			
S3 CP Avg(5.5mon)	23828.8	AvgAnnEn/MaxPeak=	65.2%		10361.7	AvgAnnEn/MaxPeak=		80.1%

	STEP II SYSTEM				STEP III SYSTEM			
Period	Total Energy Load 3/ aMW	Total Peak Load MW	Hydro Energy Load 4/ aMW	Hydro Peak Load MW	Total Energy Load 3/ aMW	Total Peak Load MW	Hydro Energy Load 4/ aMW	Hydro Peak Load MW
August 1-15	19039.5	25444	8658.9	13376	16668.1	22275	6287.5	10207
August 16-31	19020.7	25414	8641.3	13365	16651.6	22249	6272.2	10200
September	17697.7	22741	7392.7	10633	15493.4	19909	5188.4	7801
October	17095.1	23461	6737.7	11246	14965.8	20539	4608.4	8323
November	19047.5	26183	8586.5	13874	16675.1	22922	6214.0	10612
December	21047.0	28821	10414.0	16465	18425.6	25231	7792.6	12876
January	21198.0	29014	10605.3	16646	18557.7	25400	7965.0	13032
February	20157.3	27226	9686.3	14888	17646.7	23835	7175.7	11497
March	18541.7	24931	8744.6	13141	16232.3	21826	6435.2	10036
April 1-15	17581.3	23403	7493.9	11232	15391.5	20488	5304.1	8317
April 16-30	17743.8	23382	8268.1	11576	15533.8	20470	6058.1	8664
May	17201.3	22264	10534.2	13211	15058.9	19491	8391.7	10438
June	18576.0	24449	9300.0	13474	16262.3	21404	6986.3	10429
July	19682.2	26229	9430.7	14182	17230.7	22962	6979.3	10915
Annual Avg. 7/	18908.4		8999.0		16553.3		6643.9	
S2 CP Avg(20mon)	18968.2		8902.8					
S3 CP Avg(5.5mon)					17318.8		6957.1	
Joint Optimum S2 CP capability 5/ =			**8902.77**		S3 CP capability 6/ =		**6957.10**	

Notes:

1/ The PNW Area load does not include the exports, but does include pumping.

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 load of the PNW Area.

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

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

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

7/ The Annual Average is for the operating year. The Critical Period (CP) averages are for the historic water years.

TABLE 4
SUMMARY OF STEPS I, II, & III POWER REGULATIONS
FOR 2017-18 ASSURED OPERATING PLAN

	BASIC DATA		STEP I				STEP II					STEP III				
	NUMBER OF UNITS	MAXIMUM INSTALLED PEAKING CAPACITY MW	USABLE STORAGE kaf	USABLE STORAGE hm^3	CRITICAL CAPACITY FPLCC Ag1 1932 MW	CRITICAL ENERGY FELCC Avg.Gen MW	USABLE STORAGE kaf	USABLE STORAGE hm^3	CRITICAL CAPACITY FPLCC Jan 1932 MW	CRITICAL PERIOD FELCC Avg.Gen MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE kaf	USABLE STORAGE hm^3	CRITICAL CAPACITY FPLCC Jan 1930 MW	CRITICAL PERIOD FELCC Avg.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	274	93	3008	3710	144	108	98	3008	3710	330	230	96
Kerr	3	160	1219	1504	180	122	1219	1504	175	112	129	1219	1504	175	153	125
Thompson Falls	6	85	0	0	85	56	0	0	85	53	58	0	0	85	66	58
Noxon Rapids	5	554	231	285	528	151	0	0	528	132	201	0	0	528	176	201
Cabinet Gorge	4	239	0	0	262	104	0	0	262	91	125	0	0	262	117	126
Albeni Falls	3	50	1155	1425	50	22	1155	1425	20	20	21	1155	1425	20	16	19
Box Canyon	4	74	0	0	72	46	0	0	71	45	48	0	0	71	56	47
Grand Coulee	24+3SS	6684	5185	6396	6420	2022	5072	6256	6020	1823	2396	5072	6256	5195	1223	2305
Chief Joseph	27	2535	0	0	2535	1075	0	0	2535	977	1314	0	0	2535	709	1239
Wells	10	840	0	0	840	421	0	0	840	390	491	0	0	840	288	444
Chelan	2	54	677	835	53	38	676	834	51	38	44	676	834	52	50	43
Rocky Reach	11	1267	0	0	1274	609	0	0	1274	563	732	0	0	1274	409	671
Rock Island	18	513	0	0	529	276	0	0	529	259	322	0	0	529	191	295
Wanapum	10	986	0	0	825	503	0	0	825	466	590	0	0	825	330	523
Priest Rapids	10	912	0	0	770	489	0	0	770	456	561	0	0	770	331	494
Brownlee	5	675	975	1203	675	198	974	1201	675	255	285	974	1201	662	237	286
Oxbow	4	220	0	0	220	83	0	0	220	107	116	0	0	220	105	116
Ice Harbor	6	693	0	0	693	206	0	0	693	221	297	0	0	693	162	297
McNary	14	1127	0	0	1121	615	0	0	1127	590	762	0	0	1127	438	708
John Day	16	2484	535	660	2484	943	0	0	2484	917	1264	0	0	2484	688	1220
The Dalles	22+2F	2074	0	0	1875	767	0	0	1875	744	1001	0	0	1875	563	957
Bonneville	18+2F	1088	0	0	1065	554	0	0	1065	537	677	0	0	1065	419	634
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	22830	9393	28500	35154	22268	8903	11535	13000	16035	21618	6957.2	10906
c) ADDITIONAL STEP I PROJECTS																
Libby	5	600	4980	6143	572	202										
Boundary	6	1055	0	0	855	368										
Spokane Rivr Plnts 2/	24	173	104	128	166	98										
Hells Canyon	3	450	0	0	183	165										
Dworshak	3	450	2015	2485	448	154			NOT APPLICABLE TO STEPS II & III							
Lower Granite	6	932	0	0	802	160										
Little Goose	6	932	0	0	787	169										
Lower Monumental	6	932	0	0	844	165										
Pelton, Rereg,& RB	7	423	274	338	417	139										
Total added Step I		5947	7373	9094	5076	1620										
d) Total Hydro		29689	52318	64533	27906	11013	44000	54273	22268	8903	11535	13000	16035	21618	6957	10906
2. THERMAL INSTALLATIONS 3/			CpEn/AnnPk=83%		12068	9994	CpEn/AnnPk=81%		12367	10065	9909	CpEn/AnnPk=84%		12367	10362	9909
3. RESOURCE ADJUSTMENTS																
a) Hydro maintenance 4/					-4595	-12	-5.3% of hydro		-1177	n.a.	n.a.	-5.3% of hydro		-1142	n.a.	n.a.
b) Peaking reserves 5/					-4432	n.a.	-11% of resc.		-3810	n.a.	n.a.	-11% of resc.		-3738	n.a.	n.a.
c) Transmission losses 6/					-1162	-652			n.a.	n.a.	n.a.			n.a.	n.a.	n.a.
4. TOTAL RESOURCES 7/			CpEn/AnnPk=68%		29786	20344	CpEn/AnnPk=64%		29649	18968	21444	CpEn/AnnPk=60%		29105	17319	20816
5. Steps I, II, & III System Loads																
a) PNW Area firm load			CpEn/AnnPk=75%		30648	22857										
b) Net of Exports + Imports					1659	476										
c) Non-Step I resources					-1503	-808										
d) Hydro Independents					-1431	-961										
e) Miscellaneous resources					-474	-1220										
f) ...Net Step I,II,III System Load 8/			CpEn/AnnPk=70%		28900	20344	CpEn/AnnPk=65%		29014	18968	18908	CpEn/AnnPk=68%		25400	17319	16553
6. SURPLUS (4 - 5f)					886	0			636	0	2536			3705	0	4262
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		18-41				18-42					18-13				

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 1A, 1B and 3.
4/ Step I hydro maintenance from Tables 1A and 1B. Steps II/III peak hydro maintenance is the same percent as Step I coordinated Hydro; no energy maintenance loss was included because impact is negligible. Hydro maintenance energy losses are not included in Steps II & III.
5/ Steps I, II, and III peak reserves are 11% of resources.
6/ Step I transmission losses from Table 1A and 1B. Steps II & III transmission losses are not included, since it would change the energy load by the same amount.
7/ Total Resources are the sum of total lines 1b+1c+2+3. For Step I, this does not include non-Step I coordinated hydro or hydro-independents.
8/ Step I energy load from Table 1A, line 5, and August 15 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.

TABLE 5
COMPUTATION OF CANADIAN ENTITLEMENT
FOR 2017-18 ASSURED OPERATING PLAN

A. Joint Optimum Power Generation in Canada and the U.S. (From 18-42 and 18-13).
B. Optimum Power Generation in the U.S. Only (From 18-12 and 18-13 studies).
C. Optimum Power Generation in the U.S. and a 0.5 Million Acre-Feet (0.6 km3) Reduction in Total Canadian Treaty Storage (From 18-22 study).

Determination of Dependable Capacity Credited to Canadian Storage (MW)	**(A)**	**(B)**	**(C)**
Step II - Critical Period Average Generation 1/	8902.8	8900.8	8866.5
Step III - Critical Period Average Generation 2/	6957.1	6957.1	6957.1
Gain Due to Canadian Storage	1945.7	1943.7	1909.4
Average Critical Period Load Factor in percent 3/	74.60	74.60	74.60
Dependable Capacity Gain 4/	2608.2	2605.5	2559.5
Dependable Capacity Limit (from Table 4) 5/	3613.7	3613.7	3613.7
Canadian Share of Dependable Capacity 6/	**1304.1**	**1302.8**	**1279.8**
Determination of Increase in Average Annual Usable Hydro Energy (aMW)			
Step II (with Canadian Storage) 1/	**(A)**	**(B)**	**(C)**
Firm Energy 7/	8999.4	8997.4	8963.2
Thermal Displacement Energy 8/	2407.8	2406.1	2428.6
Remaining Usable Energy 9/	51.0	51.9	53.8
System Average Annual Usable Energy	11458.2	11455.5	11445.6
Step III (without Canadian Storage) 2/			
Firm Energy 7/	6644.2	6644.2	6644.2
Thermal Displacement Energy 8/	3598.5	3598.5	3598.5
Remaining Usable Energy 9/	265.4	265.4	265.4
System Average Annual Usable Energy	10508.2	10508.2	10508.2
Average Annual Usable Energy Gain 10/	950.1	947.3	937.4
Canadian Share of Average Annual Energy Gain 6/	**475.0**	**473.7**	**468.7**

1/ Step II values were obtained from AOP 18-42, 18-12 and 18-22 studies.
2/ Step III values were obtained from AOP 18-13 study.
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/ From Table 4. Does not set a precedent or necessarily imply agreememt on calculation of this value.
6/ One-half Dependable Capacity (as limited by Capacity Credit Limit) or Usable Energy Gain.
7/ From 30-year average firm load served, which includes 7 leap years (29 days in Feb.), which is slightly different than Table 3.
8/ Average secondary generation limited to Potential Thermal Displacement Market.
9/ Forty percent (40%) of the remaining secondary energy.
10/ Difference between Step II and Step III Annual Average Usable Energy.

TABLE 6
COMPARISON OF RECENT DDPB STUDIES
(English and Metric units)

	2013-14		2014-15		2015-16		2016-17		2017-18	
AVERAGE PNWA ENERGY LOAD										
Annual Load (MW)	22802.6		23013.7		22478.2		22801.8		22775.6	
January Load Factor (%) 1/	113.6		112.8		112.5		112.6		112.1	
Critical Period (CP) Avg. Load Factor (%)	74.6		74.8		73.9		74.0		74.6	
Annual Firm Exports 2/	1605.0		833.0		832.3		841.9		725.6	
Annual Firm Imports 3/	1177.0		467.0		378.6		400.4		233.1	
Annual Non-Step 1 Hydro & Misc Rsrc 4/	2841.0		2919.0		3022.4		3012.8		3130.5	
Total Annual Step 1 Load 5/	20390.0		20462.0		19909.5		20230.6		20137.6	
THERMAL INSTALLATIONS (MW) 6/										
January Peak Capability	12838.8		13734.6		12146.7		12533.5		12367.5	
CP Energy	10125.5		10215.7		9662.4		9995.3		9994.3	
CP Minimum Generation	228.1		230.3		216.6		224.8		224.8	
Average Annual System Export Sales	227.0		180.5		252.6		239.3		195.9	
Average Annual Displaceable Market	9577.7		9708.5		9111.5		9448.2		9490.6	
Average Annual Energy 7/	10031.0		10117.0		9578.8		9910.5		9909.4	
HYDRO RESOURCES (aMW)										
Average Annual Step 1 Hydro Resources 8/	11057.0		11021.0		10994.7		10991.3		10890.9	
Average Annual Step 1 Coord Hydro Load 9/	11850.0		11819.0		11793.9		11790.9		11689.3	
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 10/										
Step I 30-yr Avg Streamflow, cfs and m3/s	175361	4966	175120	4959	175084	4958	175084	4958	173390	4910
Step I CP Average, cfs and m3/s	114734	3249	114518	3243	114487	3242	114487	3242	112665	3190
Step II CP Average, cfs and m3/s	101578	2876	101396	2871	101376	2871	101376	2871	99211	2809
Step III CP Average, cfs and m3/s	56027	1587	56034	1587	56088	1588	56088	1588	54698	1549
CAPACITY BENEFITS (MW)										
Step II CP Generation	8934.7		8944.9		8951.5		8948.4		8902.8	
Step III CP Generation	6942.3		6898.7		6981.7		6974.5		6957.1	
Step II Gain over Step III	1992.4		2046.2		1969.9		1973.9		1945.7	
CANADIAN ENTITLEMENT	1335.5		1368.6		1332.3		1333.2		1304.1	
Change due to Mica Reoperation	0.0		1.5		1.2		0.0		1.3	
ENERGY BENEFITS (aMW)										
Step II Annual Firm	8897.9		8961.8		8960.1		8944.7		8999.4	
Step II Thermal Displacement	2469.5		2423.9		2383.9		2422.6		2407.8	
Step II Remaining Usable Secondary	55.9		49.1		68.1		58.6		51.0	
Step II System Average Annual Usable	11423.3		11434.8		11412.0		11425.8		11458.2	
Step III Annual Firm	6169.1		6300.7		6422.8		6354.9		6644.2	
Step III Thermal Displacement	3920.9		3879.6		3681.8		3800.3		3598.5	
Step III Remaining Usable Secondary	326.3		294.7		330.0		309.8		265.4	
Step III System Average Annual Average	10416.3		10475.1		10434.6		10465.1		10508.2	
CANADIAN ENTITLEMENT 11/	505.5		479.9		488.7		484.0		475.0	
Change due to Mica Reoperation	2.0		9.9		3.7		3.7		1.3	
STEP II PEAK CAPABILITY (MW)	31326		30944		28367		30163		29649	
STEP II PEAK LOAD (MW)	29400		29236		27306		29051		29014	
STEP III PEAK CAPABILITY (MW)	31215		30063		27703		28035		29105	
STEP III PEAK LOAD (MW)	25162		25158		23568		23992		25400	

FOOTNOTES FOR TABLE 6

1. 100 x (January) / (average annual PNWA) firm loads (Table 1A, row 1(d)).

2. Average annual total firm exports (Table 1A, row 2(k)).

3. Absolute value of average annual total firm imports (Table 1A, row 3(i)).

4. Absolute value of average annual PNWA Non-Step I Hydro and Non-Thermal Resources (Table 1A, row 4(f)).

5. Average annual total Step I load (Table 1A, row 5).

6. 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. January thermal peak capability is shown, but actual minimum peak surplus month is August 15.

7. Average annual Energy from the thermal installations (Table 1A, 6(c)).

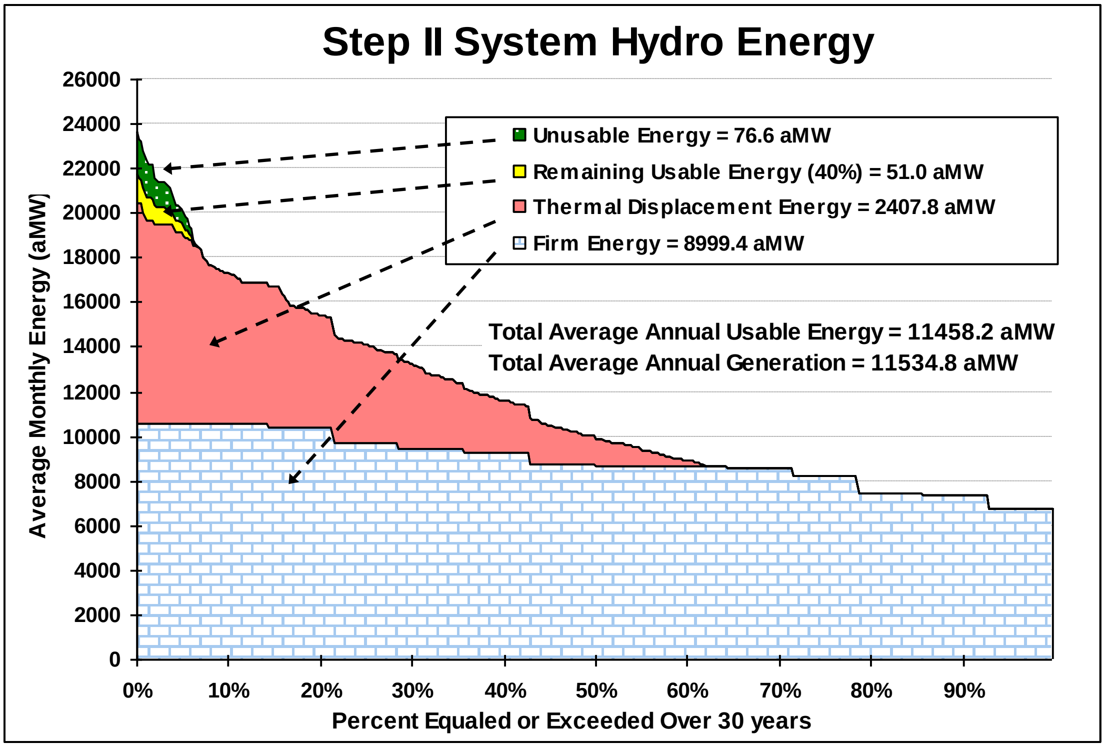
8. Average annual Step I Hydro Resources (Table 1A, row 7).

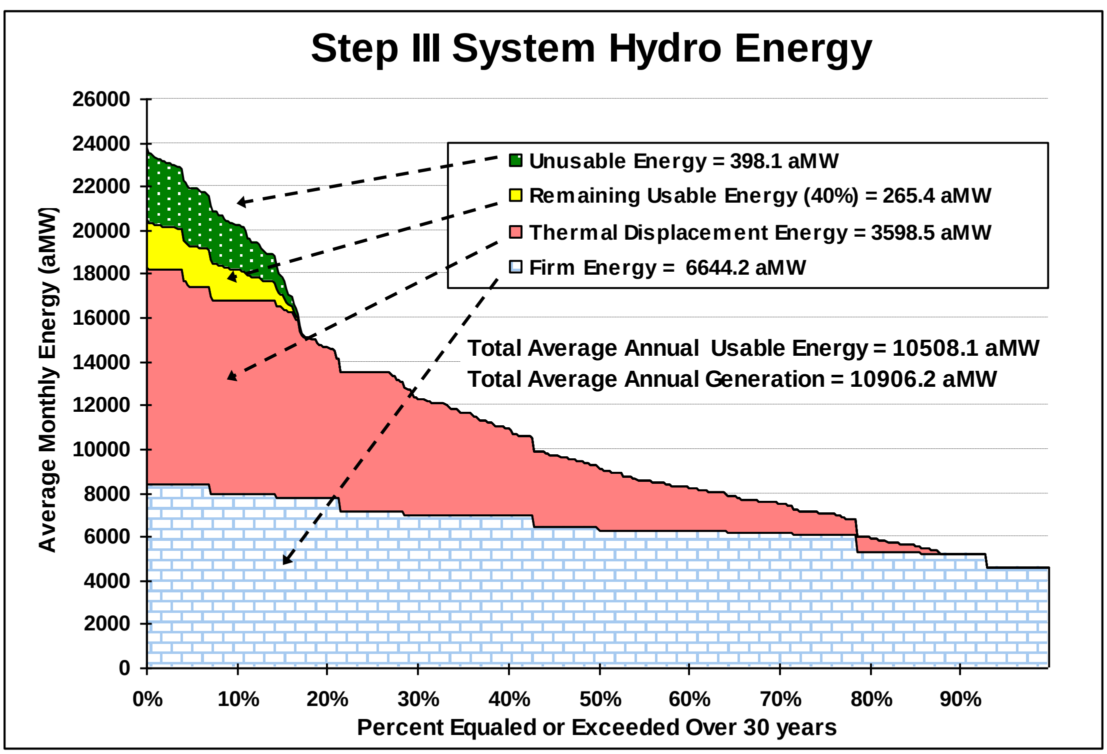
9. Average annual Step I Coordinated Hydro load (Table 1A, row 10).

10. The 2010 level modified flows were used beginning with the 2017-18 DDPB with adjustments for the Grand Coulee pumping and return flows. The 2012-13, 2013-14, 2014-15, 2015-16 and 2016-17 DDPBs, all based upon 2000 level modified flows, include updated adjustments for the Grand Coulee pumping but not for return flows.

11. The energy benefits for 2014-15, 2015-16, and 2017-18 are all based upon Step II 30-year Joint Optimum hydro regulation studies. The energy benefits for 2013-14 and 2016-17 are based upon 30-Year U.S. Optimum hydro regulation studies, which includes an adjustment (+2.0 aMW for the 2013-14 study and +3.7 aMW for the 2016-17 study, respectively) to estimate the increase in the energy entitlement that would result from a Joint Optimum operation of the Step II study.

CHART 1
DURATION CURVES OF 30-YEAR MONTHLY HYDRO GENERATION
From the 18-42 and 18-13 Studies (Average monthly MW)





Values on chart above differ from the values on Table 5 by as much as 0.1 aMW due to rounding error.