Annual Report of The Columbia River Treaty, Canada and United States Entities

01 August 2016 through
30 September 2017

2017 ANNUAL REPORT

OF THE

COLUMBIA RIVER TREATY

CANADA AND UNITED STATES ENTITIES

FOR THE PERIOD

01 AUGUST 2016 – 30 SEPTEMBER 2017

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EXECUTIVE SUMMARY

General

Water Year (WY) 2017 streamflow and snowpack conditions were higher than 2016, with the April-August runoff across the basin, measured at The Dalles, of 134.8 cubic kilometers (km^3) (109.3 Million acre feet, Maf), or 125 percent of the 30 year average (1981 – 2010). April-August runoff in the Upper Columbia (106 percent of normal measured at Keenleyside) and Kootenai basins (119 percent of normal measured at Libby) was slightly above average while runoff in the Snake Basin (142 percent of normal measured at Lower Granite) was well above average. The strong El Niño of 2016 gave way to a weak La Niña for WY 2017 which produced a very eventful water year. This year had observed periods with record rainfall and extreme cold, which resulted in the heaviest February, March and April precipitation the basin had received since at least the 1970s. The rapid snowpack increase from early February through early April set the stage for flood risk management (FRM) challenges throughout the spring. New records were set for highest average unregulated March flows at Lower Granite, Grand Coulee and The Dalles going back to 1929. For the third year in a row, calculated unregulated flows on the Snake River peaked several weeks before the rest of the Columbia Basin, and much earlier than the long-term, 80-year mean.

For the 01 August 2016 through 30 September 2017 reporting period, the Canadian Storage were operated according to the 2016-2017 and the 2017-2018 Detailed Operating Plans (DOPs), the 2003 Columbia River Treaty Flood Control Operating Plan (FCOP), and supplemental operating agreements as described below. The Libby project was operated consistently with the Libby Coordination Agreement (LCA), including the Libby Operating Plan (LOP), United States (U.S.) requirements for power, and U.S. Fish and Wildlife Service's 2006 Biological Opinion (BiOp), as clarified, and the National Oceanic and Atmospheric Administration’s National Marine Fisheries Service’s (NOAA Fisheries’) 2010 and 2014 Supplemental BiOp for operation and maintenance of the Federal Columbia River Power System (FCRPS).

Entity Agreements

During the period covered by this report, the following joint U.S.-Canadian agreements were approved by the Entities:

Date Signed by Entities	Description of Agreement
09 January 2017	Extension of the Columbia River Treaty Short-term Entity Agreement on Coordination of Libby Project Operations
30 June 2017	Columbia River Treaty Agreement on the Detailed Operating Plan for Canadian Storage 01 August 2017 through 31 July 2018

Columbia River Treaty Operating Committee Agreements

The Columbia River Treaty Operating Committee (CRTOC) completed the following supplemental operating agreements during the reporting period:

Date Signed	Description	Authority
21 July 2016	Columbia River Treaty Operating Committee Arrow Summer Storage Agreement For the Period 23 July 2016 through 31 August 2016	Detailed Operating Plan 01 August 2015 through 31 July 2016 and Detailed Operating Plan 01 August 2016 through 31 July 2017
07 December 2016	Columbia River Treaty Operating Committee Agreement on Operation of Canadian Storage for Nonpower Uses for 01 December 2016 through 31 July 2017	Detailed Operating Plan 01 August 2016 through 31 July 2017

System Storage

The 2016-17 Operating Year began on 01 August 2016 with the Canadian Storage at 15.5 km^3 (12.6 Maf), or 81.2 percent full. Canadian Storage drafted to a minimum of 3.7 km^3 (3.0 Maf), or 19.6 percent full on 31 March 2017, and refilled to 18.5 km^3 (15.0 Maf), or 96.6 percent full, on 31 July 2017. Canadian Storage operated in proportional draft mode during August 2016 through October 2016 and again during August 2017 through the end of this reporting period to meet Treaty firm loads. Throughout the Operating Year, the composite Canadian Storage targeted the Treaty Storage Regulation (TSR) study composite storage, plus any operations implemented under mutually agreed upon Supplemental Operating Agreements, including the Short Term Libby Agreement (STLA), Arrow Summer Shaping Agreement and the Nonpower Uses

Agreement (NPU). Exceptions occurred in all periods due to inadvertent draft or storage, which occurs routinely due to updated inflow forecasts or differences between forecast and actual inflows, as well as after-the-fact changes in proportional draft points.

As in past years, the CRTOC negotiated a NPU to manage Keenleyside outflows and to improve conditions for fish in both countries. Under provisions of that agreement, the U.S. Entity stored 1.2 km^3 (504 thousand second-foot-days (ksfd), 1 Maf) of flow augmentation water by the end of January 2017. Operation under the agreement helped to manage flows downstream of Keenleyside for Canadian whitefish and trout spawning protection during the January through June period. The flow augmentation water was subsequently released May through July 2017 to help meet U.S. salmon flow objectives. The majority of flow augmentation in 2017 was forced out earlier than desired due to FRM constraints. From January until the end of July 2017, Canadian Storage remained above TSR-specified levels.

The January 2017 water supply forecast for the Columbia River above The Dalles for January through July was 119.2 km^3 (96.6 Maf), or 95 percent of the 1981–2010 average. After the water supply forecast increased to 134.2 km^3 (108.8 Maf) in March, or 107 percent of the 1981-2010 average, the forecasts continued to increase in April to 161.3 km^3 (130.8 Maf), or 129 percent of 1981-2010 average. By the June 2017 forecast, the (January-July) runoff forecast had increased to 175.0 km^3 (141.9 Maf), or 140 percent of the 1981-2010 average. The actual January through July runoff for the Columbia River above The Dalles was 169.1 km^3 (137.1 Maf), or 135 percent of the 1981-2010 average. In contrast, the actual April through August runoff for the Columbia River above The Dalles was 134.8 km^3 (109.3 Maf), or 125 percent of the 1981-2010 average. This illustrates the relatively wet conditions in February and March along with strong early runoff. The 2017 water year included much higher precipitation than 2016 posing some operational challenges on FRM draft and refill timing.

Operations of the three Canadian projects (Mica, Keenleyside, and Duncan) and Libby in the United States for the 14-month period from 01August 2016 to 30 September 2017 are illustrated in Section VIII as Charts 5 through 8. The hydrographs show actual reservoir levels, discharges, inflows, and the FRM Rule Curve. The FRM Rule Curve specifies maximum month-end reservoir levels which permit timely evacuation of the reservoir to mitigate potentially high inflows from precipitation and snowmelt events.

Treaty Project Operations

Mica (Kinbasket Reservoir)

Kinbasket reached a maximum elevation in 2016 of 752.83 meters (m) (2,469.9 feet, ft), 1.55 m (5.1 ft) below full pool, on 16 November 2016 due to fairly significant weather events in the fall. The winter of 2016/2017 was significantly colder than normal across the province. As a result of low temperatures and high system loads, Columbia Basin generation ran much harder than normal. This caused the reservoir to draft quickly across December through February approaching near average levels by spring 2017. In 2017, the minimum level reached was of 728.72 m (2,390.8 ft) on 04 May 2017, about 0.67 m (2.2 ft) lower than the 2016 minimum level.

Reservoir inflows for the period February to July 2017 were about 112% of average. Due to above average inflows and low electricity demands in the spring, the reservoir filled from May to August to reach a maximum of 752.18 m (2,467.8 ft) on 19 August 2017, 2.19 m (7.2 ft) below normal full pool.

Hugh Keenleyside (Arrow Lakes Reservoir)

In Operating Year 2016 Arrow reached a maximum level of 437.24 m (1,434.5 ft), 2.90 m (9.5 ft) below full pool, on 10 June 2016. Arrow releases are regulated under the Columbia River Treaty (CRT) and its supplemental operating agreements. Under dry conditions, more Treaty water is released from Arrow Lakes Reservoir according to the principles of proportional draft under the CRT. This operation resulted in high discharges from Keenleyside across July through September 2016 and produced correspondingly low summer levels. Arrow levels reached 430.96 m and 427.88 m (1,413.9 ft and 1,403.8 ft) by 31 August and 30 September 2016, respectively.

With the arrival of heavy rainstorms in the fall (October – November 2016), the coordinated system went on to refill resulting in significantly reduced discharges from Arrow to as low as 142 cubic meters per second (m^3/s) (5.0 thousand cubic feet per second, kcfs) in November. Arrow storage subsequently refilled to slightly above average levels by 31 December 2016. Arrow then went on to draft across the winter to reach its minimum level of 427.15 m (1,401.4 ft) on 04 February 2017. By comparison, in the previous year, Arrow reached a minimum level of 424.13 m (1,391.5 ft) on 31 January 2016.

Snowpack in the Columbia Basin in 2017 was above normal due to a wetter than normal spring primarily in the U.S. Columbia Basin and the lower portion of the Canadian Columbia Basin. This resulted in an above normal runoff forecast for the entire Columbia Basin with the forecast at The Dalles reaching 125% of normal for April to August runoff. By comparison, in 2016, the Columbia runoff was 90% of normal for the April to August period.

Arrow Lakes Reservoir refilled to a maximum level of 439.58 m (1,442.2 ft), or 0.55 m (1.8 ft) below full pool, on 27 July 2017. This is about 2.35 m (7.7 ft) above the 2016 maximum level. Since then, Arrow drafted across the summer to reach about 437.24 m (1,434.5 ft) on 31 August 2017 and 434.61 m (1,425.9 ft) on 30 September 2017.

Duncan (Duncan Reservoir)

Duncan refilled to 576.47 m (1,891.3 ft), 0.21 m (0.7 ft) below full, on 08 August 2016 and then drafted to elevation 547.30 m (1,795.6 ft) on 11 April 2017. By comparison, the reservoir reached a similar minimum level of 547.21 m (1,795.3 ft) on 08 April 2016. From September 2016 through April 2017, Duncan was operated to supplement flows into Kootenay Lake, to provide spawning and incubation flows for fish downstream in the Duncan River and to meet Treaty FRM requirements. As in most years, the reservoir was drafted to near empty in late April. Duncan reached its minimum level, 547.30 m (1,795.6 ft) on 11 April 2017. By comparison, the reservoir reached a similar minimum level of 547.21 m (1,795.3 ft) on 08 April 2016.

The reservoir discharge was reduced to its minimum of 2.8 m^3/s (0.1 kcfs) in late-May to initiate reservoir refill and reduce flood risk on Kootenay Lake. Releases from Duncan were held at minimum until early July, when discharges were gradually increased to manage the rate of reservoir refill. In 2017, Duncan refilled to a maximum of 576.50 m (1,891.4 ft), 0.18 m (0.6 ft) below full pool on 13 August 2017. Duncan discharges were increased during August to facilitate drafting the reservoir to reach the summer recreation target of 575.46 m (1,888.0 ft) between 10 August and Labour Day as per the Duncan Water Use Plan Order.

Libby (Lake Koocanusa)

Lake Koocanusa ended July 2016 at elevation 745.82 m (2,446.9 ft). The project was drafted to elevation 745.72 m (2,446.6 ft) at the end of August 2016. From September through April, the project was operated to meet minimum bull trout flows and FRM requirements. On 04 May 2017,

Libby Dam reached its minimum elevation for the year of 719.15 m (2,359.4 ft) then operated to the Variable Flow (VarQ) FRM rules until the start of the sturgeon pulse. On 15 May 2017, Libby began to release the sturgeon volume 1.54 km^3 (1.2 Maf) set by the May water supply forecast of 10.1 km^3 (8.2 Maf), or 139 percent of average. The 2017 sturgeon volume was released in a double pulse operation with the first pulse to mimic the peak of the tributaries and a second pulse to mimic peak inflows to Libby Dam. The first pulse began on 15 May with project outflows ramping up to 685 m^3/s (24.2 kcfs) or powerhouse capacity for approximately 7 days followed by a flat flow of 510 m^3/s (18.0 kcfs) for 11 days. The second pulse began on 02 June with project outflows ramping up to powerhouse capacity for 9 days (03-11 June) followed by a gradual ramp down to 396 m3/s (14.0 kcfs) as the sturgeon volume was expended on 26 June. Lake Koocanusa ended the month of June at elevation 743.56 m (2,439.5 ft).

The operation for the rest of the summer, July through August, was to try to refill Libby in so far as possible and meet the 746.46 m (2,449.0 ft) target by the end of September, as required in the NOAA Fisheries BiOp and coordinated through the Technical Management Team (TMT). Libby reached its peak elevation for the summer on 02 August, 746.33 m (2,448.6 ft), which was 3.14 m (10.3 ft) below full pool. Due to low inflows, the project kept releases to the minimum bull trout flow of 255 m^3/s (9.0 kcfs) through August then ramped down to 170 m^3/s (6.0 kcfs), the minimum bull trout flow for September. Libby elevations were 745.27 m (2,445.1 ft) and 744.47 m (2,442.5 ft) at the end of August and September, respectively. The 170 m^3/s (6.0 kcfs) in September was also the requested release from Libby to help with the ongoing in-stream habitat work for the Kootenai Tribe of Idaho (KTOI). Libby held this minimum release through the end of September.

Treaty Benefits

Flood Risk Management Operations

Columbia River Basin projects were operated for FRM objectives according to the May 2003 FCOP. The 2017 runoff volumes were well above normal across the Columbia River Basin. The regulated peak outflow during the freshet from The Dalles Dam, was 12,465 m^3/s (440.2 kcfs) on 04 June 2017, and the unregulated peak flow was estimated at 20,116 m^3/s (710.4 kcfs) on 04

June 2017. The peak stage[1] observed during the freshet at Vancouver, Washington, was 5.24 m (17.2 ft) on 01 April 2017, and the estimated peak unregulated stage was 7.28 m (23.9 ft) on 03 June 2017, while the flood stage is 4.88 m (16.0 ft).

Flood Risk Management Benefits

Water Year 2017 resulted in an active FRM season due to the well above average seasonal volumes. Higher than average amounts of low level snow pack (particularly in the Snake River Basin), rain on snow, and elevated baseflow in parts of the basin resulted in some system and local FRM challenges. Reservoirs throughout the Columbia River Basin, including the Canadian Storage, were drafted during the winter and spring in preparation for flood season. The actual unregulated runoff for the overall Columbia River Basin (U.S. and Canada combined) measured at The Dalles for January through July 2017 was 169.1 km^3 (137.1 Maf), 135 percent of the 1981-2010 average. The peak regulated and estimated unregulated flows, and river stages are shown in the following tables:

Columbia River Streamflow at The Dalles Dam, Oregon

Date	Peak Unregulated Flow Estimated	Date	Peak Regulated Flow
04 June 2017	20,116 m^3/s (710.4 kcfs)	04 Jun 2017	12,465 m^3/s (440.2 kcfs)

Columbia River Stage at Vancouver, Washington

Flood Stage is 4.88 m (16.0 ft)

Date	Peak Unregulated Stage Estimated	Date	Peak Regulated Stage
03 June 2017	7.28 m (23.9 ft)	01 Apr 2017	5.25 m (17.2 ft)[1]

[1] The peak observed regulated stage at the Vancouver gage (VAPW) during the reporting period was 5.36 m (17.6 ft) which occurred on 30 March 2017 (just outside the traditional Apr-Jul freshet) due to high flows on both the Columbia and Willamette Rivers.

Hydroregulation by Duncan and Libby projects limited the peak level of Kootenay Lake at Queen's Bay to 533.74 m (1,751.1 ft) on 09 June 2017. Without regulation from those Treaty dams, the peak level would have been approximately 536.05 m (1,758.7 ft). As documented in the 2003 FCOP, flood damages commence at Nelson when the Kootenay Lake elevation reaches 534.92 m (1,755.0 ft). Duncan, Keenleyside, Mica and Libby projects limited the peak flow of the Columbia River at Trail, just upstream of Birchbank, British Columbia, to 4,301 m^3/s (151.9 kcfs) on 11 June 2017. Absent the dams, but with natural lake effects at Kootenay Lake, the flow would have been approximately 8,062 m^3/s (284.7 kcfs). For reference as per the DOP16, the bankfull flow at Birchbank is estimated to be 5,097.0 m^3/s (180 kcfs).

Power Benefits

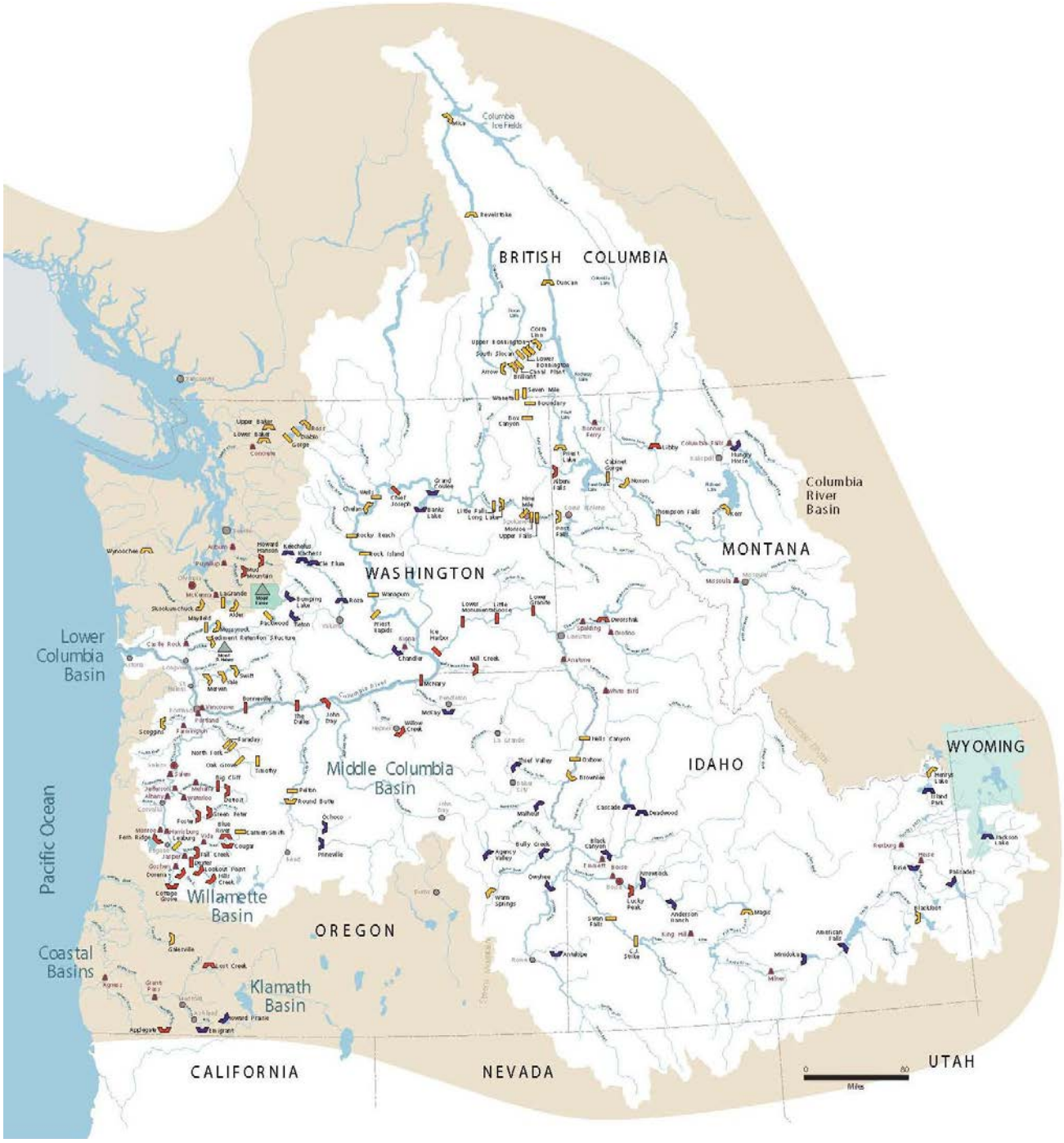
A Determination of Downstream Power Benefits (DDPB) is computed in conjunction with the Assured Operating Plan (AOP). This computation represents the optimized generation from downstream U.S. projects that could have been produced by an optimized Canadian/U.S. system. The DDPB is prepared in accordance with the Treaty and Protocol, and other Entity Agreements. The Canadian Entitlement (CE) represents one-half of the DDPB. For the period 01 August 2016 through 31 July 2017, the CE amount, before deducting transmission losses, was 484.0 average Megawatts (aMW) of energy, scheduled at rates up to 1333 Megawatts (MW). From 01 August 2017 through 30 September 2017, the amount, before deducting transmission losses, was 475.0 aMW of energy, scheduled at rates up to 1304 MW.

During the course of the 2016-2017 Operating Year, there was one CE delivery curtailment event. On 14 December 2016, there was a two hour event totaling 10 Megawatt hours (MWh) of curtailment. The 10 MWh was successfully redelivered on 17 December 2016. Actual U.S. power benefits from the operation of CRT storage are unknown and can only be roughly estimated. Canadian Storage has such a large impact on the U.S. system operation that its absence would significantly affect operating procedures, nonpower requirements, loads and resources, and market conditions, thus making any benefit analysis highly speculative. A rough estimate of the impact on downstream U.S. power generation during the 2016-17 Operating Year, with and without the regulation of Canadian Storage, based on the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER) that includes minimum flow and spill requirements for U.S. fishery objectives, is 630 aMW. The increase in hydro power

generation occurred primarily in the winter months, December through March. No quantification of this benefit was reported by the Entities.

Treaty operating plans are designed to adapt to streamflow and water supply conditions that arise and evolve over the Operating Year. Operating Plans are implemented through the TSR study which incorporates streamflows, water supply forecasts and operating parameters dependent on runoff conditions during the Operating Year, and which update the specified Canadian Storage draft points twice a month. This report discusses conditions as realized for the 2016-17 Operating Year and describes the response of Canadian Storage to the actual inflows and water supply conditions which occurred this year. The emphasis of the Treaty is for FRM and power. Other risk mitigation benefits (such as fish habitat and navigation) associated with the Treaty's flexibility to adapt to the broad array of water conditions are not addressed or quantified in this report.

Columbia Basin Map



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Acronyms and Abbreviations

AER.....Actual Energy Regulation

aMW……... .....Average Megawatts

AOP…….....Assured Operating Plan

B.C. Hydro .....British Columbia Hydro and Power Authority

BiOp .....Biological Opinion

BPA.....Bonneville Power Administration

CE……...Canadian Entitlement

CEEA .....Canadian Entitlement Exchange Agreement

cfs .....Cubic feet per second

CRC.....Critical Rule Curve

CRT.....Columbia River Treaty

CRTHC .....Columbia River Treaty Hydrometeorological Committee

CRTOC .....Columbia River Treaty Operating Committee

DDPB.....Determination of Downstream Power Benefits

DOP.....Detailed Operating Plan

DRL.....Duncan River below the Lardeau R. confluence

FCOP.....Flood Control Operating Plan

FCRPS.....Federal Columbia River Power System

FRM .....Flood Risk Management

ft .....feet

hm^3 .....Cubic hectometers

ICF .....Initial Controlled Flow

IJC .....International Joint Commission

kaf .....Thousand acre feet

kcfs.....Thousand cubic feet per second

KLBC.....Kootenay Lake Board of Control

km^3 .....Cubic kilometer (one billion cubic meters)

ksfd.....Thousand second-foot-days (= kcfs x days)

LCA.....Libby Coordination Agreement

LOP .....Libby Operating Plan

m .....Meter

m^3/s .....Cubic meters per second

Maf.....Million acre-feet

MG ….....Major General

MW .....Megawatt

MWh .....Megawatt hour

NOAA Fisheries.....National Oceanic and Atmospheric Administration's National Marine Fisheries Service, formerly NMFS

NPU.....Nonpower Uses Agreement

NTSA .....Non-Treaty Storage Agreement

NWRFC .....Northwest River Forecast Center

ORC .....Operating Rule Curve

PEB .....Permanent Engineering Board

PEBCOM .....PEB Engineering Committee

PNCA.....Pacific Northwest Coordination Agreement

POP .....Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans for Canadian Storage

SSARR .....Streamflow Synthesis and Reservoir Regulation (computer simulation)

STLA…….....Columbia River Treaty Short-Term Libby Agreement on Coordination of Project Operations

TMT……Technical Management Team

TSR…… Treaty Storage Regulation

U.S. .....United States

USACE .....U.S. Army Corps of Engineers

VarQ.....Variable flow flood risk management

VRC .....Variable refill curves

WUP.....Water Use Plan

WY .....Water Year

Unit Conversions

Distance

1 km = 3280.839895 ft

1 m = 3.280839895 ft

Volume

1 m^3 = 35.314666721 ft^3

1 km^3 = 35314666721 ft^3

1 km^3 = 0.810713194 Maf

1 hm^3 = 0.000810713 Maf

1 hm^3 = 0.81071319 kaf

1 hm^3 = 0.40873 ksfd

1 ksfd = 1.98347 kaf

Flow

1 m^3/s = 35.31466672 cfs

Project Naming Conventions

Hugh Keenleyside Dam

The official name of the project is Hugh Keenleyside Dam, but will be referred to as Keenleyside in the report. The official name of the associated reservoir is Arrow Lakes Reservoir, but will be referred to as Arrow in the report i.e. “Arrow” will always refer to the reservoir and “Keenleyside” will always refer to the dam/project/facility. Note that when the Treaty was signed, the dam was referred to as “Arrow”; the re-naming to Hugh Keenleyside Dam was completed later.

Mica Dam and Powerhouse

The official name of the project/facility is Mica Dam and Powerhouse, but will be referred to as Mica in the report. The official name of the associated reservoir is Kinbasket Lake Reservoir, but will be referred to in the report as Kinbasket.

Libby Dam

The official name of the project is Libby Dam, but will be referred to as Libby in the report. The official name of the associated reservoir is Lake Koocanusa.

Duncan Dam

The official name of the project is Duncan Dam, but will be referred to as Duncan in the report. The official name of the associated reservoir is Duncan Reservoir, but will be referred to in the report as Duncan.

I – INTRODUCTION

This annual Columbia River Treaty Entity Report is for the Water Year (WY) 2017, 01 October 2016 through 30 September 2017, with additional information on the operation of Mica, Keenleyside, Duncan, and Libby dams, as needed, to also cover the reservoir system Operating Year, 01 August 2016 through 31 July 2017. Also described are the power and flood risk management (FRM) effects downstream in Canada and the United States (U.S.). This report is the 51st of a series of annual reports covering the period since the ratification of the Columbia River Treaty (Treaty, CRT) in September 1964.

Duncan, Keenleyside, and Mica in Canada were constructed as required under the CRT, and Libby in the U.S. was constructed as provided for by the CRT. Treaty storage in Canada (Canadian Storage) is operated for the primary purposes of FRM and increasing hydroelectric power generation in Canada and the U.S. In 1964, the Canadian and the U.S. governments each designated at least one Entity to formulate and carry out the operating arrangements necessary to implement the CRT. The Canadian Entity for these purposes is British Columbia Hydro and Power Authority (B.C. Hydro). The Canadian Entity for the limited purpose of making arrangements for disposal of all or portions of the Canadian Entitlement (CE) within the U.S. is the government of the Province of British Columbia. The U.S. Entity is the Administrator & Chief Executive Officer of Bonneville Power Administration (BPA) and the Division Commander of the Northwestern Division, U.S. Army Corps of Engineers (USACE). These Treaty Entities (USACE, BPA, and B.C. Hydro) have arranged for a series of Treaty-related agreements to provide benefits beyond those for FRM and power, related to values such as fisheries, recreation, and others.

The following is a summary of key features of the CRT and related documents:

1. Canada was to provide 19.1 cubic kilometers (km^3) (15.5 Million acre-feet (Maf) of usable storage. This has been accomplished with 8.6 km^3 (7.0 Maf) in Kinbasket, 8.8 km^3 (7.1 Maf) in Arrow, and 1.7 km^3 (1.4 Maf) in Duncan.
2. For the purpose of computing downstream power benefits, the U.S. base system hydroelectric facilities will be operated in a manner that makes the most effective use of the improved streamflow resulting from operation of the Canadian Storage.

3. The U.S. and Canada are to share equally the downstream power benefits pre-determined to be generated in the U.S. resulting from operation of the Canadian Storage.
4. The U.S. paid Canada a lump sum of $64.4 million (U.S.) for one-half of the present worth of expected future FRM benefits in the U.S. to September 2024, resulting from operation of the Canadian Storage.
5. Under certain specified conditions, the U.S. has the option of requesting the evacuation of additional FRM space above that specified in the CRT, for a payment of $1.875 million (U.S.) plus power losses for each of the first four requests for this "on-call" storage. No requests under this provision have been made to date.
6. The U.S. had the option (which it exercised) to construct Libby Dam with a reservoir that extends 67.6 kilometers (42 miles) into Canada and for which Canada agreed to make the land available.
7. Both Canada and the U.S. have the right to make diversions of water for consumptive uses. In addition, since September 1984, Canada has had the option of making, for power purposes, specific diversions of the Kootenay River into the headwaters of the Columbia River. This has not been exercised.
8. Differences arising under the Treaty that cannot be resolved by Canada and the U.S. may be referred to either the International Joint Commission (IJC) or to arbitration by an appropriate tribunal.
9. The Treaty shall remain in force for at least 60 years from its date of ratification, 16 September 1964, after which either Government has the option to terminate most sections of the Treaty if a minimum of 10 years advance notice has been given. No termination notices have been made to date.
10. In the Canadian Entitlement Purchase Agreement of 13 August 1964, Canada sold its entitlement to downstream power benefits (Canadian Entitlement) to the Columbia Storage Power Exchange (a consortium of U.S. utilities) for 30 years beginning at Duncan on 01 April 1968, Keenleyside on 01 April 1969, and Mica on 01 April 1973. That sale has now expired and all CE has reverted to British Columbia provincial ownership and is delivered to the Canadian-U.S. border under the terms of the ‘Aspects Agreement’.

11. Canada and the U.S. each appointed Entities to implement Treaty provisions, as well as two members each to a joint Permanent Engineering Board (PEB), to review and report on operations under the CRT.

II - TREATY ORGANIZATION

Entities

There was one meeting of the CRT Entities (including the Canadian and U.S. Entities and Entity Coordinators) during the year on 08 February 2017 in Vancouver, B.C.

The members of the two Entities at the end of the report period were:

UNITED STATES ENTITY

Mr. Elliot Mainzer, Chairman
Administrator &
Chief Executive Officer
Bonneville Power Administration
Department of Energy
Portland, Oregon

MG Scott A. Spellmon, Member
Division Engineer
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY

Mr. Chris O'Riley, Chair
President & Chief Operating Officer
British Columbia
Hydro and Power Authority
Vancouver, British Columbia

The Entities have designated alternates to act on behalf of the primaries in their absence, appointed in the U.S. by a Memorandum of Agreement between BPA and USACE, and in Canada by the B.C. Hydro Board of Directors. The BPA Administrator's alternate is the BPA Deputy Administrator and MG Spellmon's alternate is the Deputy Division Engineer. The alternate for Mr. O'Riley is the B.C. Hydro Executive Vice President of Operations.

The Entities have appointed Coordinators, Secretaries, and two joint standing committees to assist in CRT implementation activities that are described in subsequent paragraphs. The primary duties and responsibilities of the Entities as specified in the CRT and related documents are to:

1. Plan and exchange information relating to facilities used to obtain the benefits contemplated by the CRT;
2. Calculate and arrange for delivery of hydroelectric power to which Canada is entitled and the amounts payable to the U.S. for standby transmission services (the latter is no longer in effect);

3. Operate a hydrometeorological system;
4. Assist and cooperate with the PEB in the discharge of its functions;
5. Prepare and implement Flood Control Operating Plans (FCOPs) for the use of Canadian Storage;
6. Prepare Assured Operating Plans (AOPs) for Canadian Storage and determine the resulting downstream power benefits that Canada is entitled to receive; and
7. Prepare and implement Detailed Operating Plans (DOPs) that may produce results more advantageous to both countries than those that would arise from operation under AOPs.

Additionally, the CRT provides that the two governments, by exchange of diplomatic notes, may empower or charge the Entities with any other matter coming within the scope of the CRT, or appoint additional Entities for specific purposes. The Province of British Columbia is a Canadian Entity for the limited purpose of implementing the Disposal Agreement.

Entity Coordinators & Secretaries

The Entities have appointed Coordinators from members of their respective staffs to help manage and coordinate CRT related work and Secretaries to serve as information focal points on all CRT matters within their organizations.

Following are the appointed Coordinators and Secretaries:

UNITED STATES ENTITY COORDINATORS

Kieran Connolly*
Vice President,
Generation and Asset Management
Bonneville Power Administration
Portland, Oregon

David J. Ponganis
Director, Civil Works & Management
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY COORDINATOR

Heather Matthews
Director,
Generation System Operations
B.C. Hydro
Burnaby, British Columbia

UNITED STATES ENTITY SECRETARY	CANADIAN ENTITY SECRETARY
Jennifer Boyer Regional Coordination Power and Operations Planning Bonneville Power Administration Portland, Oregon	Jeremy Benson Manager, Planning and Licensing Generation Resource Management B.C. Hydro Burnaby, British Columbia

* Kieran Connolly was appointed to replace Rick Pendergrass on 23 September 2016.

Columbia River Treaty Operating Committee

The Columbia River Treaty Operating Committee (CRTOC) was established in September 1968 by the Entities and is responsible for preparing and implementing operating plans as required by the CRT, making studies and otherwise assisting the Entities, as needed. The CRTOC consists of the following eight members:

UNITED STATES SECTION	CANADIAN SECTION
Pamela Kingsbury, BPA, Alt. Chair Steven B. Barton, USACE, Alt. Chair Julie H. Ammann, USACE Trevor Downen, BPA	Darren Sherbot, B.C. Hydro, Chair Gillian Kong, B.C. Hydro Herbert Louie, B.C. Hydro Doug D. Robinson, B.C. Hydro

The CRTOC met during the reporting period to exchange information, approve work plans, discuss issues, agree on operating plans, and brief the PEB and Permanent Engineering Board Engineering Committee (PEBCOM). There were six regular meetings held every other month alternating between Canada and the U.S., plus one meeting with the PEBCOM. During the period covered by this report, the CRTOC:

- Coordinated the operation of the CRT storage in accordance with the then-current hydroelectric operating plans and FCOP;
- Coordinated changes to procedures and reviewed scheduled delivery of the CE according to the CRT and related agreements;
- Completed the 01 August 2017 through 31 July 2018 DOP;
- Completed two supplemental operating agreements for Canadian Storage;

- Implemented the Libby Coordination Agreement (LCA) including the July 2016 update to the Libby Operating Plan (LOP), delivery of one average megawatt (MW) of power;
- Implemented the Short-term Libby Agreement (STLA) including scheduling Arrow provisional water transactions and associated financial payments;
- Completed the LOP for 2017-2018, 27 September 2017;
- Briefed both PEBCOM and PEB on Entity activities, and completed the 2016 Entity Annual Report.

These aspects of the CRTOC's work are described in the following sections of this report, which have been prepared by the CRTOC with the assistance of others.

CRT Operating Committee at the PEBCOM meeting on October, 2017. Pictured are (L to R), Trevor Downen (member), Doug Robinson (member), Jeremy Benson (Canada Secretary), Gillian Kong (member), Darren Sherbot (Canada Chair), Steve Barton (U.S. Alternate Chair), Pam Kingsbury (U.S. Alternate Chair), Stephanie Smith, Herbert Louie (member), Jen Boyer (U.S. Secretary).

Columbia River Treaty Hydrometeorological Committee

The Columbia River Treaty Hydrometeorological Committee (CRTHC) was established in September 1968 by the Entities and is responsible for coordinating hydrometeorological data

collection, data exchange and water supply forecasting for the CRT projects in accordance with the Treaty and otherwise assisting the Entities, as needed. The Committee consists of the following four members:

UNITED STATES SECTION	**CANADIAN SECTION**
Ann McManamon, BPA Co-Chair	Stephanie Smith, B.C. Hydro, Chair
William Proctor, USACE Co-Chair	Georg Jost, B.C. Hydro, Member

The CRTHC conducted bi-monthly conference calls and met in person twice during the 01 October 2016 – 30 September 2017 period:

Meeting 79: 08 May 2017, USACE

Meeting 80: 07 September 2017, B.C. Hydro

The 2016 CRTHC Annual Report was completed in December 2016 and distributed prior to the end of the year.

Forecasting

The CRTHC can agree to alter inputs to the prescribed Treaty water supply forecasting procedures if there is a strong justification and agreement that one of the inputs is unduly influencing the forecast results. The committee has a procedure to review any proposed changes and decide whether the change is considered to be justified.

The October 2016 precipitation in Canada, Montana, and Idaho was significantly above normal (precipitation in the Upper Columbia (above Arrow Dam) and Kootenay regions was 166 and 275 percent of normal[2], respectively) and caused the water supply forecast procedures for the Treaty projects to be artificially high. B.C. Hydro and later Seattle District USACE proposed adjustments to the input variables to capture the effect of this above normal precipitation while not unduly influencing the water supply forecasts. Those adjustments remained in place through the season.

[2] Data from Northwest River Forecast Center (NWRFC), Monthly Precipitation Table (archived for WY 2017) https://www.nwrfc.noaa.gov/water_supply/wy_summary/wy_summary.php?tab=5

There was one data submittal error in the original February Treaty Storage Regulation (TSR) as B.C. Hydro and BPA found a small discrepancy in the observed Arrow total inflow in early February. Water supply volumes for Arrow Reservoir (Hugh Keenleyside Dam) are computed differently for the observed and forecasted periods. The forecasted inflows for Arrow produced by B.C. Hydro do not include a regulated Whatshan forecast. However, the observed values for after the fact do include a regulated Whatshan outflow. To correct this discrepancy, the forecasted inflows for Arrow submitted by BPA for the Actual Energy Regulation (AER)/TSR will contain forecasted inflows for Whatshan, with the assumption that with the limited storage at Whatshan, its inflows and outflows are approximately equal. This created no significant impact to the AER/TSR studies and this process was documented in the POP.

In September of 2016, CRTHC made the recommendation to the Operating Committee to use the ESP forecast prepared on the third working day of each month, rather than the fifth working day for the 2017 operating year. Changing the date of the forecast had little impact on forecast accuracy but did provide 2-4 days of additional operational time. The purpose for this recommendation was to move up the operational decision making, so that decisions such as FRM directives would be initiated earlier and provide more time to reach FRM draft targets. This process was adopted by the Operating Committee in 2017 and both CRTHC and the Operating Committee support continuing this process in 2018.

In addition, the current generation of B.C. Hydro's statistical models was developed in mid-2000s from data for the period of 1966-2002 and became operational in 2007. CRTOC requested new error terms to capture the increased variability in the forecasts. This required an update in the statistical water supply forecast equations. B.C. Hydro has prepared a new set of statistical regression water supply forecast models to incorporate the more recent historical record, to update the forecast error terms and to generate seasonal volume forecasts instead of monthly forecasts. The CRTHC has reviewed the new proposed equations and based on that review has recommended the use of the new equations to CRTOC for use during the 2018 operating season. The new equations were subsequently approved by CRTOC and the errors and hedges were added to "Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans for Canadian Storage," (also referred to as the "POP") Appendix 8 for 2018.

Data Exchange

There have been ongoing issues with data exchange between the USACE, BPA and B.C. Hydro. There were issues with respect to data retrieval for BPA. Part of the problem is an issue around user accounts that require frequent password changes. In addition, there has also been an issue with data retrieval method due to continued tightening of IT security. USACE is working with BPA staff directly to resolve the issues. Part of the solution is a new system that does not rely on IPASS accounts. USACE staff is meeting monthly with BPA to keep track of progress and to resolve any ongoing issues. In addition, during August, changes were made to the ciphers used to encrypt data on the B.C. Hydro SFTP server which prevented anyone from accessing the site. USACE updated its ciphers and could then log into the B.C. Hydro server. Staff from B.C. Hydro and USACE were able to get the SFTP data transfers reestablished. Agencies worked together to solve any issues and there were not any delays in the TSR studies or other data applications.

Stations

The CRTHC routinely reviews the basin gauging network for adequacy. At this time, the CRTHC believes that the station network is adequate for Treaty purposes. CRTHC added clarification on how it comes to this determination in the 2015 CRTHC Annual Report.

B.C. Hydro performed some ‘ground-truthing’ of a snow pillow in the Arrow drainage that was reporting anomalously low snow measurements early in the season. It was found that while the snow data was low, the station was reporting correctly and snowpack was simply not increasing at this particular station. The validation of the reported snow water equivalent values was very helpful in planning operations for the Treaty projects.

The Committee reviews the adequacy of the hydrometeorological network every year based on the status of the stations and data quality, and if the data meet model input requirements. In the process of updating the water supply procedures for the Canadian projects, B.C. Hydro conducted a review of the sites available for developing those procedures and found that there were adequate stations for the process. The CRTHC believes that the current station network is adequate for making valid forecasts in the Columbia Basin.

Permanent Engineering Board

Provisions for the establishment of the Permanent Engineering Board (PEB) and its duties and responsibilities are included in the CRT and related documents. The members of the PEB at present are:

UNITED STATES SECTION	**CANADIAN SECTION**
James C. Dalton, Chair Washington, D.C.	Dr. Niall O'Dea, Chair Ottawa, Ontario
Edward Sienkiewicz, Member Newberg, Oregon	Tim Newton, Member Vancouver, British Columbia
Sean Smith, (interim) Alternate* Washington, D.C.	Renata Kurschner, Alternate** Delta, British Columbia
Steve Oliver, Alternate Portland, Oregon	Les MacLaren, Alternate Victoria, British Columbia

The following serve as Secretaries to the Board:

Jerry W. Webb, Secretary Washington, D.C.	Darcy Blais, Secretary Ottawa, Ontario

* Dr. Pietrowsky retired 30 April 2017, Sean Smith is acting as the interim alternate.

** Glen Davidson retired 31 March 2017, Renata Kurschner was nominated as the alternate.

Under the CRT, the PEB is to assemble records of flows of the Columbia River and the Kootenay River at the international boundary. The PEB is also to report to both governments if there is substantial deviation from the hydroelectric operating plans or the FCOP, and, if appropriate, include recommendations for remedial action. Additionally, the PEB is to:

- Assist in reconciling differences that may arise between the Entities;
- Make periodic inspections and obtain reports, as needed, from the Entities to assure that CRT objectives are being met;
- Prepare an annual report to both governments and special reports when appropriate;

- Consult with the Entities in the establishment and operation of a hydrometeorological system; and
- Investigate and report on any other CRT related matters at the request of either government.

The Entities continued their cooperation with the PEB during the past year by providing copies of Entity agreements, operating plans, CRTOC agreements, updates to hydrometeorological documents, personnel appointments, pertinent correspondence, and the annual Entity report to the PEB for their information and review. The annual joint meeting of the PEB and the Entities was held on 07-08 February 2017 in Vancouver, B.C. The Entities and the PEB met to discuss the current status of the CRT Review, the preparation and implementation of operating plans, the Libby Variable Flow (VarQ) FRM issues and other topics requested by the PEB. The STLA was extended for another year allowing additional time to complete and review studies.

PEB Engineering Committee

The PEB has established the PEBCOM to assist in carrying out its duties. The PEBCOM met with the Operating Committee on 26 October 2016 in Portland, Oregon. The members of PEBCOM at the end of this reporting period were:

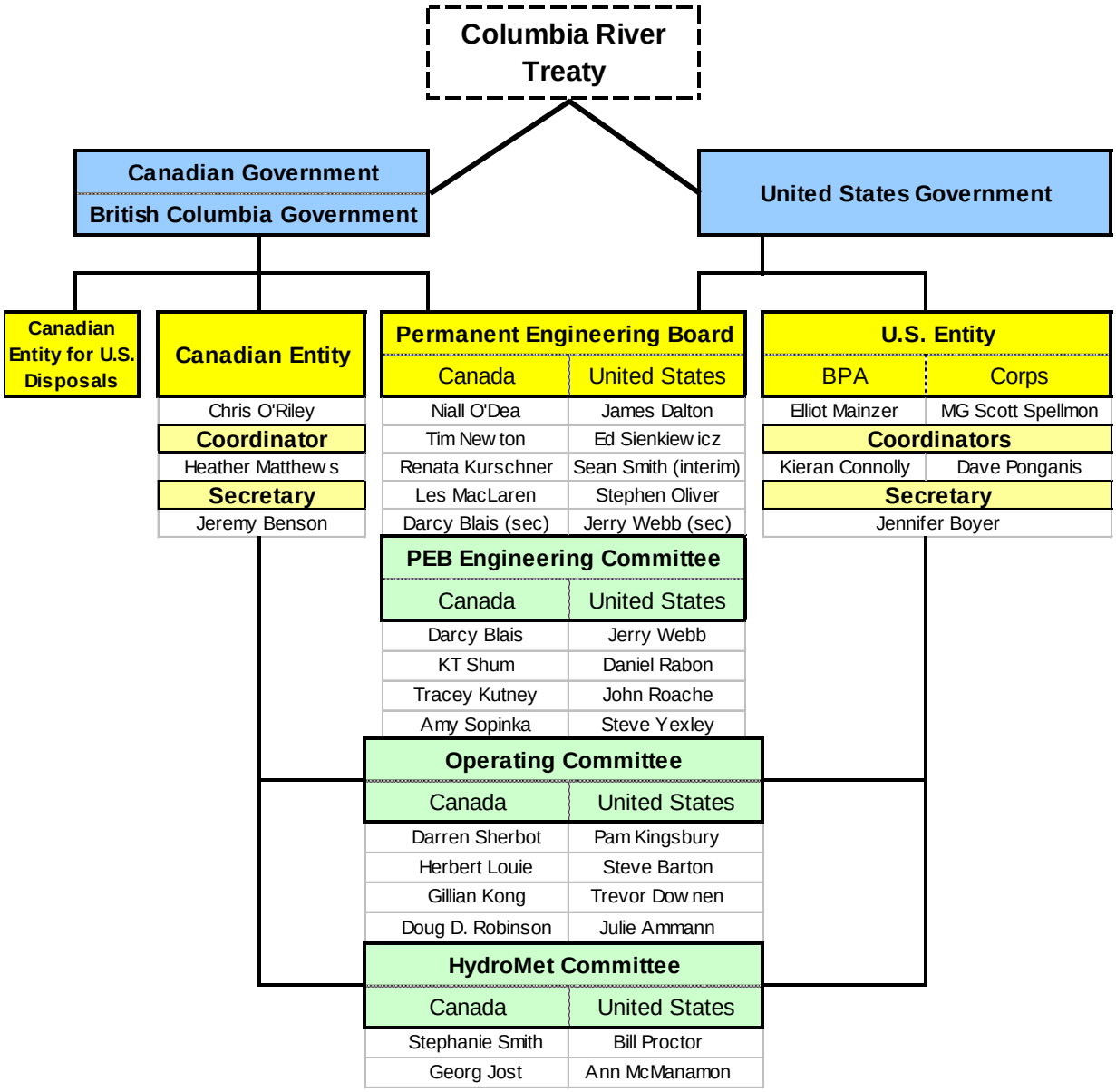
UNITED STATES SECTION	**CANADIAN SECTION**
Jerry W. Webb, Chair Washington, D.C.	Darcy Blais, Chair Ottawa, Ontario
Steve Yexley, Member* Lakewood, CO	Tracey Kutney, Member Ottawa, Ontario
Daniel Rabon, Member** Washington, DC	Dr. K.T. Shum, Member Victoria, British Columbia
John Roache, Member Boise, Idaho	Dr. Amy Sopinka, Member*** Victoria, British Columbia

* Mr. Yexley was appointed to replace Mr. Patton on 01 October 2016.
** Mr. Rabon was appointed to replace Mr. Sadiki on 01 June 2017.
*** Dr. Sopinka was appointed to replace Chris Trumpy on 26 September 2017.

International Joint Commission

The IJC was created under the Boundary Waters Treaty of 1909 between Great Britain (on behalf of Canada) and the U.S. Its principal functions are rendering decisions on the use of boundary waters, investigating important problems arising along the common frontier not necessarily connected with waterways, and making recommendations on any question referred to it by either government. If the Entities or the PEB cannot resolve a dispute concerning the CRT, that dispute may be referred to the IJC for resolution. The current IJC membership includes U.S. Section Chair Lana Pollack, Canadian Section Chair Gordon Walker, U.S. members Rich Moy and Dereth Glance, and the other Canadian members are Benoit Bouchard and Richard Morgan. The IJC writes Orders to implement decisions relating to boundary waters and also appoints local Boards of Control to insure compliance with IJC Orders and to keep the IJC informed. There are three IJC Boards of Control west of the Continental Divide: the International Columbia River Board of Control, the International Osoyoos Lake Board of Control, and the International Kootenay Lake Board of Control (KLBC), which oversees the implementation of the 1938 IJC Order on Kootenay Lake.

Organization Chart for the Columbia River Treaty



Notes:

1) The Entities and the PEB are creations of the Treaty, and all report directly to their respective governments.

2) The Operating Committee and the HydroMet Committee report to the Entities; the PEBCOM reports to the PEB.

3) CRT XIV2(f): The Entities are tasked with "*assisting and cooperating with the PEB*".

4) CRT XV2(c): Similarly, the PEB is directed to *"assist in reconciling differences concerning technical or operational matters that may arise between the entities"*.

III - OPERATING ARRANGEMENTS

Power and Flood Control Operating Plans

The CRT requires that the reservoirs constructed in Canada be operated pursuant to FRM and hydroelectric operating plans developed under Annex A of the CRT which:

1. Stipulates that the U.S. Entity will submit FCOPs.
2. States that the Canadian Entity will operate in accordance with FRM storage diagrams or any variation which the Entities agree will not reduce the desired aim of the FRM plan; and
3. Provides for the development of assured hydroelectric operating plans for Canadian Storage for the 6th succeeding year of operation (i.e., 5 years in advance).

Article XIV.2.k of the CRT provides that a DOP be developed that may produce results more advantageous to both countries than the AOP. The Protocol to the CRT provides further detail and clarification of the principles and requirements of the CRT.

The POP signed December 2003 (as amended), together with the "Columbia River Treaty Flood Control Operating Plan" (also referred to as the "FCOP") dated May 2003 (as revised), establish and explain the general criteria used to develop the AOP and DOP, and operate CRT storage during the period covered by this report.

The planning and operation of CRT Storage as discussed on the following pages are for the 2016-2017 Operating Year from 01 August 2016 through 30 September 2017. The operation of Canadian Storage was guided by the 2016-2017 DOP, the 2017-2018 DOP and supplemental operating agreements. The DOP required a semi-monthly TSR study to determine end-of-month storage obligations (prior to any adjustments associated with supplemental operating agreements). The TSR included all operating criteria from, and was based on, the Step I Joint Optimum Power Hydroregulation Study from the 2016-2017 AOP, with agreed changes. Most of the hydrographs and reservoir charts in this report are for a 14-month period from 01 August 2016 through 30 September 2017.

Assured Operating Plans

Prior to the reporting period, the Entities completed the AOP 2020 and four subsequent AOPs through 2024. The CRTOC conducted a careful review of the 2020-2024 AOP load, resource and other data assumptions and completed the AOP for the middle year, AOP 2022. The Entities agreed that the results of the AOP 2022 suite of studies would be used for the two prior years (AOP 2020 and AOP 2021) and for the two subsequent years (AOP 2023 and AOP 2024). Thus, all five AOPs were signed by the Entities in January 2016. The 2019-2020 through 2023-2024 AOPs and Determination of Downstream Power Benefits (DDPB) are not precedent-setting for future AOP or DDPB studies and are not to be construed as representing a past practice or procedure or constituting a Treaty modification to or revised interpretation of the Treaty.

Determination of Downstream Power Benefits

For each Operating Year, the DDPB resulting from Canadian Storage operation is made in conjunction with the AOP according to procedures defined in the CRT, Annexes, and Protocol, and the 2003 POP agreement (except for modifications noted in the AOP/DDPB documents). In conjunction with the 2019-2020 through 2023-2024 AOP studies, the Entities completed studies for the 2019-2020 through 2023-2024 DDPBs.

Canadian Entitlement for the Operating Year

For the period 01 August 2016 through 31 July 2017, the CE amount, before deducting transmission losses, was 484.0 average Megawatts (aMW) of energy, scheduled at rates up to 1,333 MW capacity. From 01 August 2017 through 30 September 2017, the amount, before deducting transmission losses, was 475.0 aMW of energy, scheduled at rates up to 1,304 MW capacity. The CE obligation was determined by the 2016-2017 and 2017-2018 AOP/DDPBs. During the course of the 2016-2017 Operating Year, there was a single curtailment event totaling 10 Megawatt hours (MWh) over two hours on 14 December 2016, which was successfully redelivered on 17 Dec 2016.

Detailed Operating Plans

During the period covered by this report, the CRTOC used the DOP dated June 2016 for 01 August 2016 through 31 July 2017, and the DOP dated June 2017 for 01 August 2017 through 30 September 2018, to guide Canadian Storage operations. These DOPs established criteria for determining the Operating Rule Curves (ORCs), proportional draft points, as well as other operating criteria for use in actual operations. The 2016-2017 and 2017-2018 DOPs were based respectively on the 2016-2017 AOP and 2017-2018 AOP loads and resources, rule curves, and other operating criteria with agreed changes for both Canadian and U.S. projects. The 2016-2017 and 2017-2018 AOPs included a FRM allocation of 4.4 km^3 (3.6 Maf) at Arrow and 5.0 km^3 (4.08 Maf) at Kinbasket. The 2016-2017 DOP and 2017-2018 DOP operating criteria were used to develop the TSR studies for implementation of Canadian Storage operations. These operating criteria came from the 2016-2017 and the 2021-2022 AOPs, respectively. The changes from the AOP were mainly updates to FRM upper rule curves, hydro-independent data, incorporation of updated forecast errors and distribution factors, plant data, Grand Coulee pumping estimates and updated storage/elevation table, and 2010 level modified flows.

The TSR studies were updated twice monthly throughout the reporting period for current inflow forecasts, FRM curves and variable refill curves (VRCs), and actual unregulated inflows for the previous month. The TSR and supplemental operating agreements defined the end-of-period draft rights for Canadian Storage. The VRCs and FRM requirements, subsequent to 01 January 2017, were determined on the basis of seasonal volume runoff forecasts during actual operation. The VRC calculations for Canadian reservoirs and Lake Koocanusa for the 2016-2017 Operating Year are shown in Tables 2 through 5. The calculation in Table 5 for Libby's VRCs was used in the TSR study only and was not used in actual operations. The CRTOC directed the regulation of the Canadian Storage on a weekly basis throughout the year, in accordance with the applicable DOPs, the STLA and supplemental operating agreements.

Libby Coordination Agreement

During the period covered by this report, the LCA[3] was supplemented by the Short-Term Entity Agreement on Coordination of Libby Project Operations (Short-Term Libby Agreement; STLA). The LCA required delivery to the U.S. Entity of one (1) aMW, shaped flat, over the entire 2016-2017 Operating Year. The most recent LOP is dated 27 September 2017. The STLA, signed by the Entities in September 2013, was intended to address issues raised by the Canadian entity regarding VarQ operations at Libby until 31 August 2015. The STLA provided the Canadian Entity additional flexibility to draft and store at Arrow. The STLA has been amended three times allowing the agreement to remain in effect until 31 August 2018. During the term that the STLA is in effect, Section 10 and Attachment C of the LCA are suspended. Other portions of the LCA remain in effect.

Entity Agreements

During the period covered by this report, the following joint U.S.-Canadian agreements were approved by the Entities:

Date Signed by Entities	Description of Agreement
09 January 2017	Extension of the Columbia River Treaty Short-term Entity Agreement on Coordination of Libby Project Operations
30 June 2017	Columbia River Treaty Agreement on the Detailed Operating Plan for Canadian Storage 01 August 2017 through 31 July 2018

Columbia River Treaty Operating Committee Agreements

During the period covered by this report, the CRTOC approved the following joint U.S.-Canadian Storage agreements:

[3] "Libby Coordination Agreement" (LCA) refers to the "Columbia River Treaty Entity Agreement Coordinating the Operation of the Libby Project With the Operation Of Hydroelectric Plants on the Kootenay River and Elsewhere in Canada," dated 16 February 2000.

Date Signed	Description	Authority
21 July 2016	Columbia River Treaty Operating Committee Arrow Summer Storage Agreement For the Period 23 July 2016 through 31 August 2016	Detailed Operating Plan 01 August 2015 through 31 July 2016 and Detailed Operating Plan 01 August 2016 through 31 July 2017
07 December 2016	Columbia River Treaty Operating Committee Agreement on Operation of Canadian Storage for Nonpower Uses for 0 December 2016 through 31 July 2017	Detailed Operating Plan 01 August 2016 through 31 July 2017

Long Term Non-Treaty Storage Agreement

The Long Term Non-Treaty Storage Agreement (NTSA), executed in April 2012, was used by BPA and B.C. Hydro for power purposes through Operating Year 2016-2017. In accordance with the Entity agreement that approved the 2012 NTSA contract between BPA and B.C. Hydro, the CRTOC monitored the storage and release operations under the Agreement throughout the Operating Year to ensure they did not adversely impact the operation of CRT storage required by the DOPs. BPA and B.C. Hydro developed a bilateral agreement that allowed storage, and subsequent release, of NTSA water using of Recallable accounts for the period the period 08 October 2016 through 31 March 2017, providing mutual power and nonpower benefits during the period.

IV - WEATHER AND STREAMFLOW

While annual average temperatures in the 2017 Water Year continued a multi-year trend of averaging slightly above the 30-year mean, both extreme cold and heat, and extreme wet and dry episodes affected the basin, which in turn significantly impacted treaty operations. Also, for the third year in a row, calculated unregulated flows on the Snake River peaked several weeks before the rest of the Columbia Basin, and much earlier than the long-term, 80-year mean.

After the strong El Niño of 2016, a weak La Niña developed over the tropical Pacific as the 2017 water year began, with below average sea surface temperatures along the equator between the dateline and the west coast of South America persisting through late February (Figure 1). While there is some correlation between ENSO state and Columbia Basin water supplies, the correlation between La Niña episodes and water supplies is weak with a wide historical spread. For example the extremely wet winter of 1996-97 and extremely dry year of 2000-01 both took place during similarly weak La Niña episodes (Figure 2).

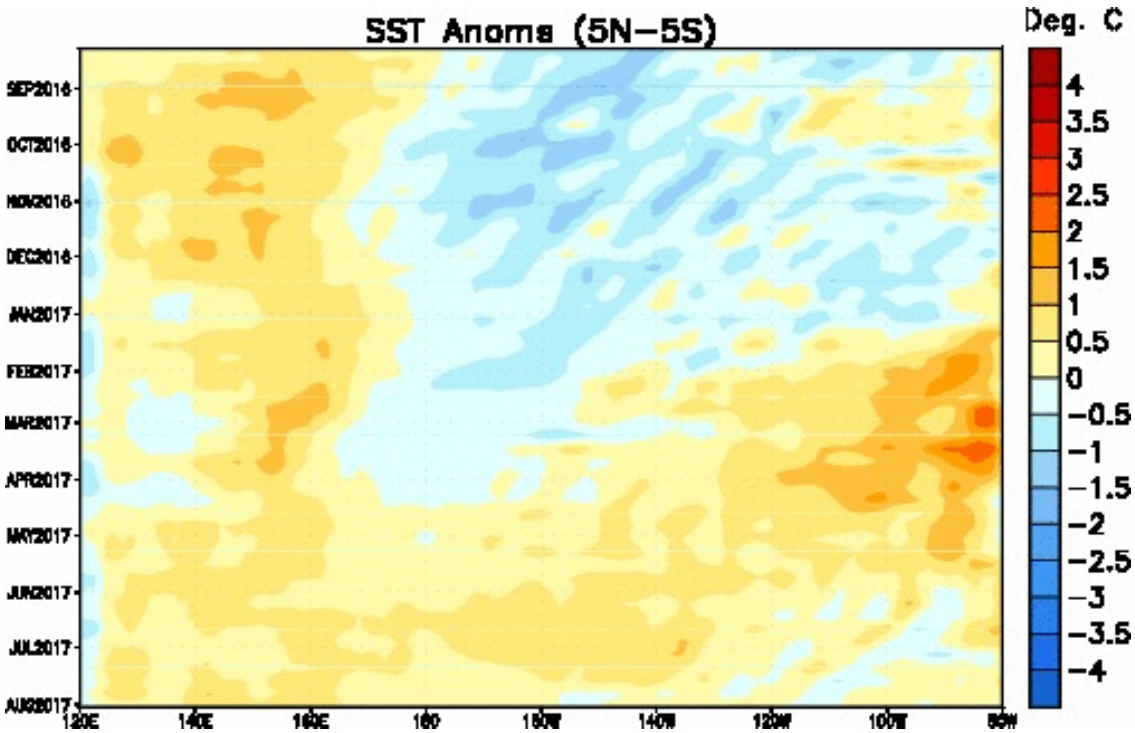


Figure 1: Sea surface temperature anomalies along the equator over the Pacific, September 2016 (top) through August 2017 (bottom).

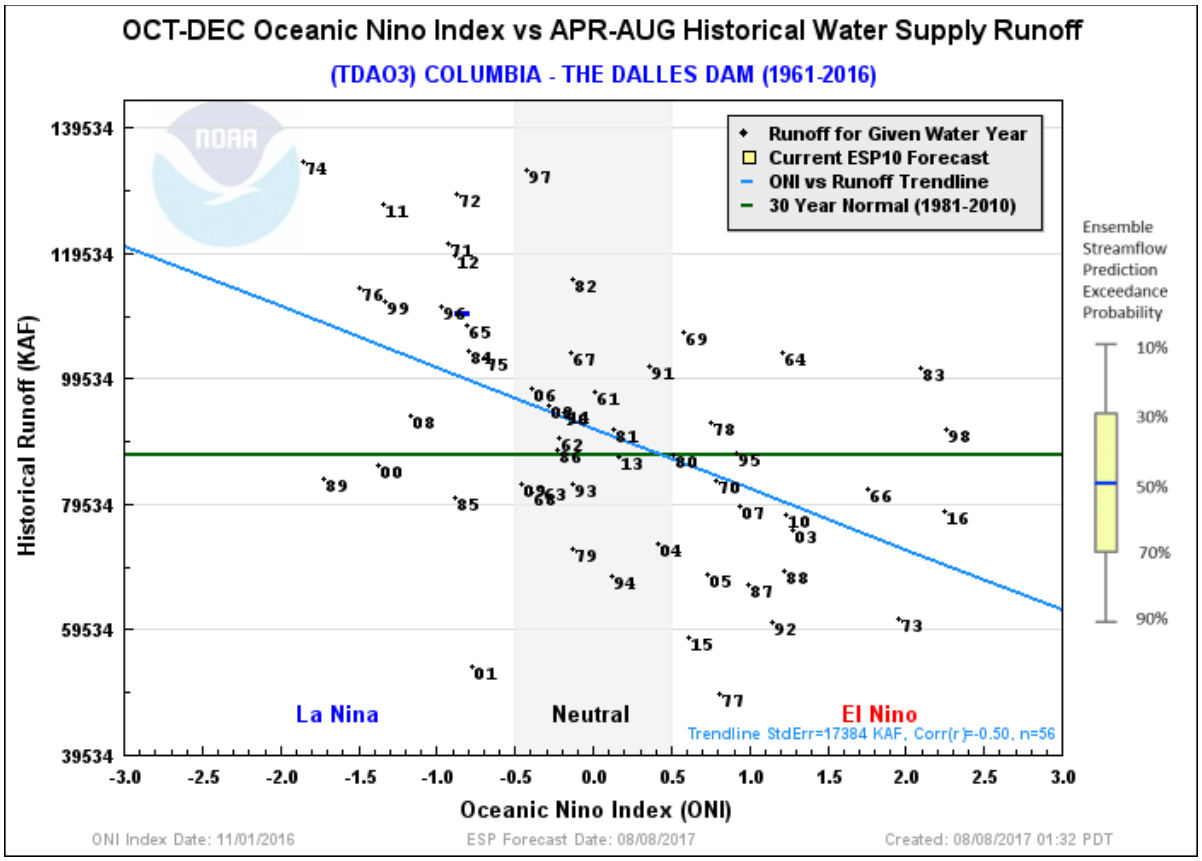


Figure 2: Comparison between April-August volumes at The Dalles by year (y axis) versus October-December ENSO ONI index (x axis), 1965-2016.

The very eventful water year began with a series of strong subtropical systems, including the remnants of Typhoon Songda on October 15, which brought 60-70 mph winds to coastal Oregon, Washington and British Columbia and even a rare EF-2 Tornado in Manzanita, OR. In what became a common theme in 2017, the basin experienced its wettest October on record – the first of five monthly precipitation records to be eclipsed since reliable basin precipitation records were consolidated in 1976. The record rainfall saturated soils for the upcoming winter, but also stressed statistical water supply forecast equations used for treaty rule curve calculations, particularly in the upper Columbia and Kootenai basins[4].

The next extreme weather to impact the basin came in the form of bitter cold and low elevation snow, the latter of which was most noticeable in the major coastal metropolitan areas and in normally snow-free lower-elevation areas across the Snake River basin. After a mild and

[4] Adjustments were made by B.C. Hydro and Seattle USACE to reduce the impacts of the very high precipitation totals on the regression forecasts by limiting the precipitation totals used in the forecast equations as coordinated through the CRTHC.

dry November, Arctic air masses dropped several times from northwest Canada into the Columbia Basin in December, January and the first half of February, with each Arctic intrusion quickly overrun by incoming Pacific storm systems and attendant moisture feeds. Three cold snaps were recorded across the region: December 15-17, January 02-07 (the coldest of the three) and January 11-15. While only a few daily record low temperatures were set, the December 15-January 15 period was the coldest month-long stretch of weather since December, 2008.

The combination of Arctic air masses and overrunning moisture led to several major snow and ice storms down to sea level, including the region's major metropolitan areas on December 07-09 (heaviest in southern British Columbia), January 10-11 (heaviest in Oregon and southern Washington), and February 05-06 (heaviest in western Washington). For much of the Columbia Basin, the precipitation that fell into the Artic air was actually lighter than usual for December and January. In the Snake Basin though, the precipitation was well above average and led to record snowpacks at unusually low elevations where automated snow measurements are generally lacking. This unaccounted snow pack can result in errors in the runoff forecasts.

The bitter cold and snow was then followed in mid-February through April by milder temperatures and a series of increasingly wet and rather warm storms. While no particular storm was noteworthy, wave after wave of heavy rain and mountain snow added up to the heaviest precipitation the basin as a whole has received in February, March and April since at least the 1970s. While snow piled up rapidly in higher elevations, the heavy and persistent valley rains fell into unusually deep low elevation snow and initiated unusually early flooding, especially in the Snake Basin and eastern Washington. Flows peaked for the year at Lower Granite on March 16 at around 6,513 cubic meters per second (m^3/s) (230 thousand cubic feet per second, kcfs), with unusually high March mainstem crests throughout the U.S. portion of the basin. New records were set for highest average unregulated March flows at Lower Granite, Grand Coulee and The Dalles going back to 1929. Despite the increasing low elevation rains, the rapid snowpack increase from early February (Figure 3) through early April (Figure 4) set the stage for ongoing, significant FRM challenges throughout the spring.

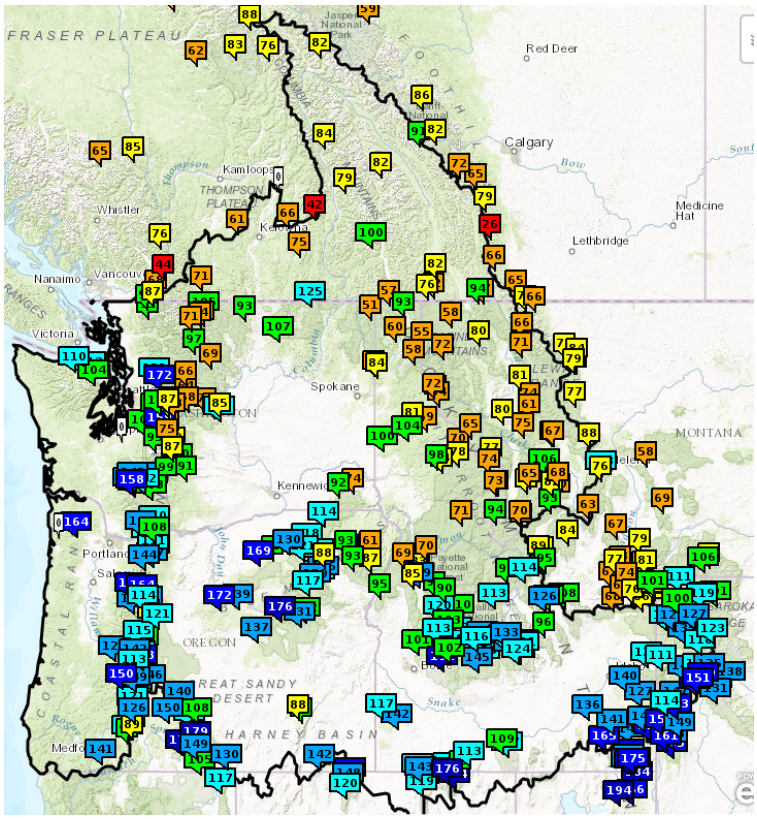


Figure 3: Snowpack % of Average, 01 February 2017, (NWRFC).

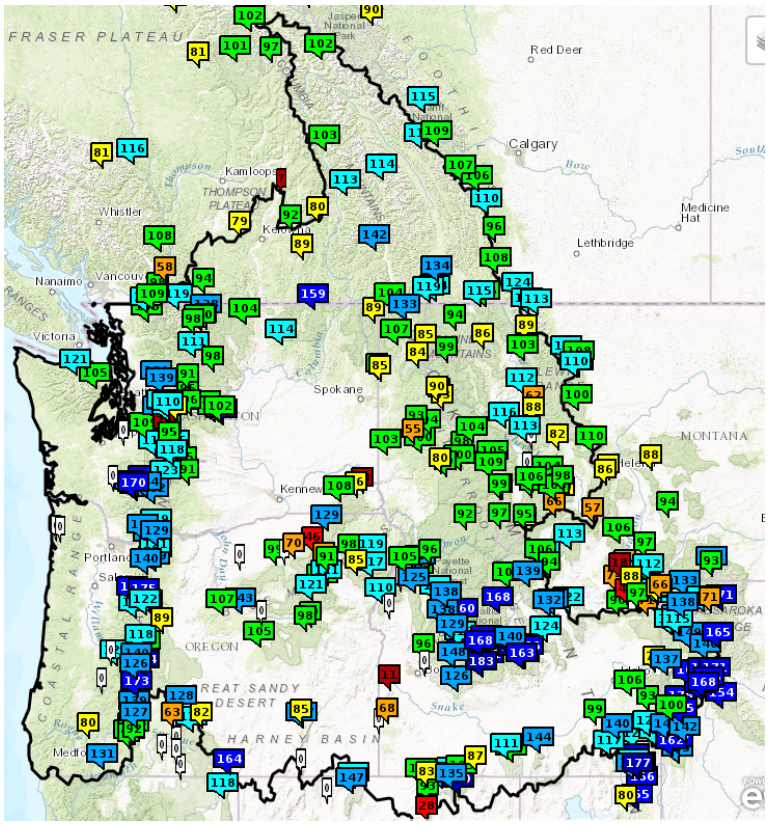


Figure 4: Snowpack % of average, 02 April 2017 (NWRFC).

With the late winter-early spring record precipitation came a near record run-up in water supply forecasts (Figure 5). The Official April-August Forecast used for Federal Columbia River Power System (FCRPS) operations issued on 03 February at The Dalles was only 102.1 km^3 (82.8 Maf) or 95 percent of the 30-year average. By 03 March the forecast climbed to 113.9 km^3 (92.3 Maf) or 105 percent of average, and by 05 April the forecast had climbed to 129.5 km^3 (105.0 Maf) or 120 percent of average. The 27.4 km^3 (22.2 Maf) jump in April-August forecasts over a two month period was one of the larger water supply forecast changes on record, either up or down, since the NWRFC began to issue regular, monthly water supply forecasts in 1980, rivaling the 25 Maf forecast increase for 07 April – 06 June in 2011. The jump in January-July volume forecasts at The Dalles was even more spectacular increasing 46.3 km^3 (37.5 Maf) from 03 February through 05 April.

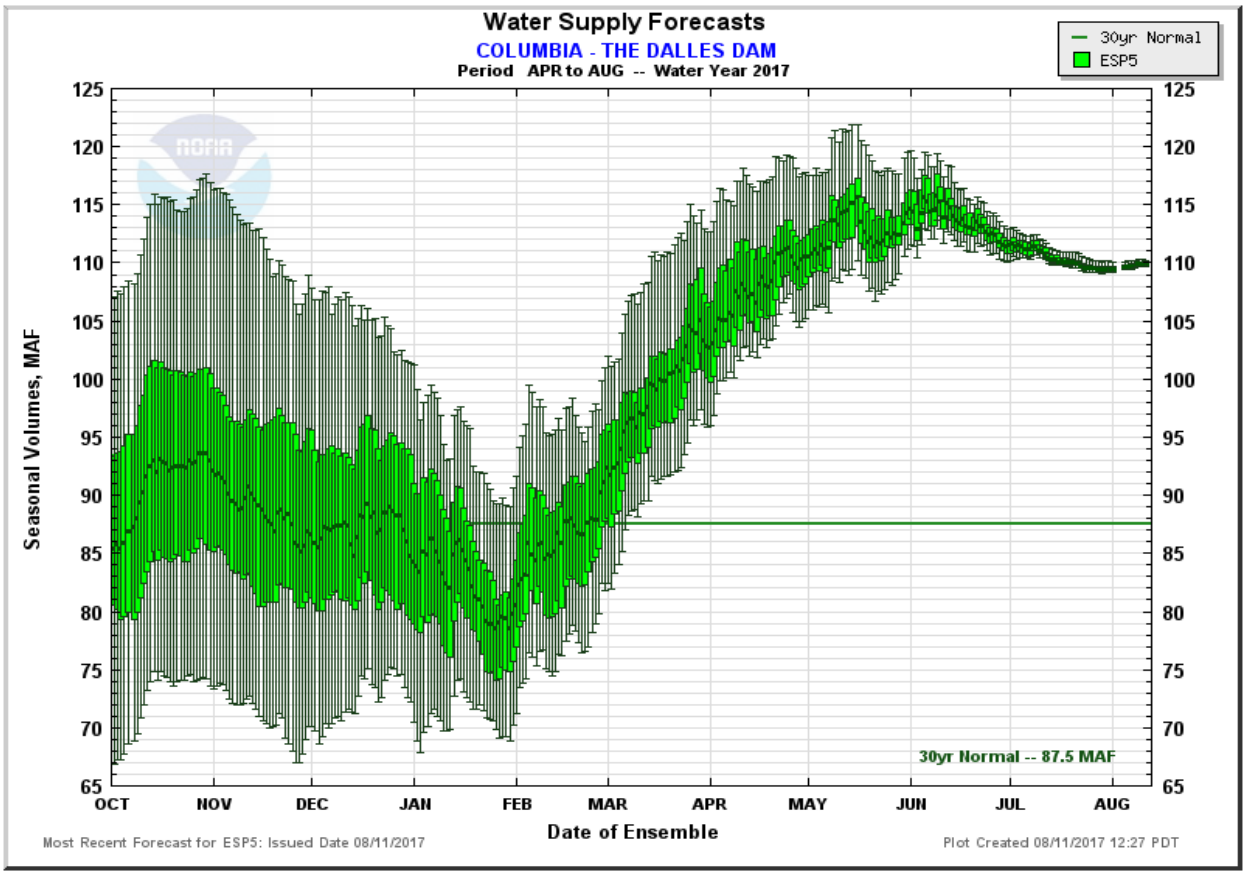


Figure 5: Daily ESP April-August water supply forecasts issued by NWRFC at The Dalles, 2017.

After the cold and very wet late winter and early spring, mild and somewhat drier weather took hold over the basin which helped to gradually ease the risk of system wide flooding in May

and June, despite a calculated, unregulated flow peak of 20,116 m^3/s (710.4 kcfs) at The Dalles on 04 June 2017– the highest unregulated peak since 2011. However, several rounds of strong thunderstorms combined with the spring snowmelt to cause serious flooding in south central British Columbia, particularly around Kamloops and Kelowna and along the Kettle and Okanagan Valley.

After such active weather since October, the basin flipped to an entirely different weather pattern in July. For the first time all year, a blocking upper level ridge developed over eastern portions of the basin for the first half of the month, before shifting west to just off the coast for the first half of August. This not only led to the driest July since records were consolidated in 1976, but also the worst 3-day heat wave in the basin since July 2009 when temperatures soared to 35-42°C (95-108 °F) from 02 - 04 August, on both sides of the Cascades and even along the immediate Pacific Coast.

Columbia Basin Weather

	Temperature	**Precipitation**	**Precipitation**	**Precipitation**
Location	**Columbia Basin above The Dalle** **Departure from the 1981-2017 average (ºC / ºF)**	**Columbia River above Grand Coulee** **Percent of the 1981-2010 average (%)**	**Snake River above Ice Harbor** **Percent of the 1981-2010 average (%)**	**Columbia River above The Dalle** **Percent of the 1981-2010 average (%)**
August 2016	+ 0.3 / +0.6	48%	12%	31%
September 2016	-0.6 / -1.1	103%	132%	103%
October 2016	+ 0.3 / +0.6	**248%**	**241%**	**246%**
November 2016	+ 3.4 / +6.2	72%	36%	56%
December 2016	-3.2 / -5.7	76%	126%	94%
January 2017	-3.9 / -7.0	47%	122%	78%
February 2017	-0.3 / -0.5	**198%**	**214%**	**195%**
March 2017	+1.1 / +1.9	**202%**	161%	**176%**
April 2017	-0.9 / -1.6	**131%**	122%	**129%**
May 2017	+0.3 / +0.5	75%	55%	66%
June 2017	+0.6 / +1.0	67%	84%	69%
July 2017	+2.4 / +4.3	**13%**	**24%**	**15%**
August 2017	+2.6 / +4.7	18%	27%	20%
September 2017	+0.8 / +1.5	70%	165%	104%
Water Year 2017	**+0.3 / +0.6**	**103%**	**118%**	**108%**

(Temperature and precipitation data from NWRFC. Record highest precipitation since 1976, according to BPA runoff processor records, highlighted in blue. Record lowest in red.)

Streamflow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 01 August through 30 September 2017 are shown in Section VIII on Charts 5 through 7. Libby hydrographs are shown in Chart 8. Observed flows and unregulated flows (computed using the USACE Hydrologic Engineering Center's Reservoir System Simulation (HEC-ResSim or ResSim) model with SSARR[5] routing for Kootenay Lake, Columbia River at Birchbank, Grand Coulee, and The Dalles are shown on Charts 9 through 12, respectively. A plot of the flows that would occur at The Dalles if regulated only by the four Treaty reservoirs is provided in Chart 13 along with the observed and unregulated flows at The Dalles for comparison.

The peak-unregulated discharge for the Columbia River at The Dalles was 20,116 m^3/s (710.4 kcfs) on 04 June 2017, based on the USACE ResSim model run. The average monthly unregulated values shown in the table in the following section are from the NWRFC. The values from NWRFC do not reflect the effects of natural lakes, whereas the USACE ResSim model does. Natural lake effects cause attenuation and dampening of flows; thus, the ResSim model simulations provide lower flows than the NWRFC tabulations. As per the table below, the average unregulated August 2016 - July 2017 streamflow at The Dalles was above average at 6,609 m^3/s (233.4 kcfs), with a corresponding runoff volume of 208.5 km^3 (169.0 Maf) (129 percent of 1981-2010 average) for the same period. This is approximately 34 percent higher than last year's annual runoff.

[5] SSARR stands for Streamflow Synthesis and Reservoir Regulation and is a computer simulation model.

Columbia River Unregulated Streamflow

Time Period	Columbia River at Grand Coulee			Columbia River at The Dalles		
	Unregulated Flow		Percent of Normal	Unregulated Flow		Percent of Normal
	kcfs	m^3/s		Kcfs	m^3/s	
Aug-16	71.7	2,030	77	93.0	2,633	74
Sep-16	47.3	1,339	84	67.8	1,920	78
Oct-16	84.4	2,390	186	125.8	3,562	152
Nov-16	87.3	2,472	179	152.8	4,327	162
Dec-16	48.7	1,379	122	85.7	2,427	94
Jan-17	35.1	994	88	76.9	2,178	79
Feb-17	60.6	1,716	138	159.0	4,502	138
Mar-17	135.0	3,823	225	333.3	9,438	225
Apr-17	169.3	4,794	141	365.9	10,361	158
May-17	337.3	9,551	134	582.2	16,486	141
Jun-17	345.8	9,792	118	543.2	15,382	124
Jul-17	157.7	4,466	89	214.1	6,063	91
Aug-17	73.1	2,070	78	101.1	2,863	81
Sep-17	47.7	1,351	85	76.2	2,158	88
Aug-Jul Average	**131.9**	**3,735**	**124**	**233.4**	**6,609**	**129**

(Source of unregulated flow: NWRFC Runoff Processor)

Seasonal Runoff Forecasts and Volumes

Seasonal runoff volumes for the April-August 2017 period, adjusted to exclude the effects of regulation of upstream storage, are listed below for eight locations in the Columbia River Basin:

Location	Volume in km^3	Volume in MAF	Percentage of 1981-2010 Average
Libby Reservoir Inflow	8.6	7.0	119%
Duncan Reservoir Inflow	2.7	2.2	109%
Mica Reservoir Inflow	14.3	11.6	106%
Arrow Reservoir Inflow	28.6	23.2	106%
Columbia River at Birchbank	53.3	43.2	111%
Grand Coulee Reservoir Inflow	80.9	65.6	116%
Snake River at Lower Granite	37.0	30.0	142%
Columbia River at The Dalles	134.8	109.3	125%

(Source: NWRFC Runoff Processor)

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2017 for a large number of locations in the Columbia River Basin and updated at the beginning of each month from December to June as the season advanced. Table 1 and Table 1M list the April through August inflow volume forecasts for Mica, Keenleyside, Duncan, and Libby projects as well as The Dalles. The actual runoff volume for these five locations is also given in Tables 1 and 1M. The forecasts for Mica, Keenleyside, and Duncan inflow were prepared by B.C. Hydro. The forecasts for the lower Columbia River inflows were prepared by the NWRFC. The Libby inflow forecast was prepared by USACE. The April 2017 forecast of January through July runoff for the Columbia River above The Dalles was 161.3 km^3 (130.8 Maf) and the actual observed runoff was 169.1 km^3 (137.1 Maf).

The following tabulations summarize the monthly forecasts since 1985 of the January-July runoff for the Columbia River above The Dalles compared with the actual runoff. The average January-July runoff volume for the period of 1981-2010 is 125.1 km^3 (101.4 Maf).

Historic Seasonal Runoff Forecasts and Volumes (km3)

The Dalles, OR Volume Runoff Forecasts in km^3 (Jan-Jul)							
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Actual**
1985	161.6	134.4	129.5	121.6	121.6	123.3	108.2
1986	119.4	115.1	127.0	130.7	133.2	133.2	133.6
1987	109.7	101.0	96.2	98.7	94.6	93.5	94.4
1988	97.7	92.3	89.7	91.3	93.9	92.5	90.9
1989	124.6	125.8	116.2	122.7	121.6	119.5	111.8
1990	106.7	124.6	128.3	118.4	118.4	122.7	123.0
1991	143.1	135.7	132.0	130.7	130.7	128.3	132.1
1992	114.2	109.9	103.0	87.8	87.8	83.6	86.8
1993	114.2	106.7	95.3	94.5	88.7	106.2	108.5
1994	98.3	94.1	96.3	90.3	93.1	94.2	92.5
1995	124.7	122.9	116.3	122.9	122.9	120.8	128.3
1996	143.1	150.5	160.4	155.4	165.3	173.9	171.8
1997	170.2	178.9	175.2	183.8	188.7	196.1	196.1
1998	106.6	117.4	113.1	112.0	109.9	124.6	128.3
1999	143.1	148.0	160.4	157.9	153.0	151.7	153.1
2000	129.5	130.7	129.5	129.5	129.5	125.8	120.9
2001	99.2	81.9	72.3	69.2	69.7	68.5	71.8
2002	123.3	125.8	120.0	118.9	121.1	123.3	128.0
2003	99.3	93.3	92.4	105.2	111.3	110.1	108.2
2004	127.0	123.3	114.6	103.9	98.1	105.0	102.4
2005	105.6	101.6	87.2	91.0	92.1	98.4	100.3
2006	124.6	136.9	132.0	132.0	135.7	136.9	141.5
2007	129.5	124.6	123.3	123.3	122.2	118.9	118.0
2008	125.8	127.0	127.0	124.6	120.0	121.1	122.4
2009	116.8	114.6	106.3	113.5	112.4	113.5	111.3
2010	109.2	97.7	88.6	86.0	87.5	91.3	104.5
2011	128.3	135.7	134.4	144.3	157.9	173.9	169.0
2012	106.1	112.6	121.9	139.2	148.1	145.3	159.7
2013	126.4	113.5	110.7	112.4	114.0	115.8	120.5
2014	118.5	98.7	126.0	129.4	135.1	132.8	133.3
2015	126.6	128.0	113.1	118.3	106.7	106.1	103.2
2016	116.1	117.4	126.9	129.1	137.9	123.4	120.4
2017	119.1	115.2	134.2	161.3	168.9	175.0	169.1
Minimum	97.7	81.9	72.3	69.2	69.7	68.5	71.8
Median	119.4	117.4	120.0	121.6	121.1	121.1	120.5
Maximum	170.2	178.9	175.2	183.8	188.7	196.1	196.1

Historic Seasonal Runoff Forecasts and Volumes (Maf)

The Dalles, OR Volume Runoff Forecasts in Maf (Jan-Jul)							
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Actual**
1985	131.0	109.0	105.0	98.6	98.6	100.0	87.7
1986	96.8	93.3	103.0	106.0	108.0	108.0	108.3
1987	88.9	81.9	78.0	80.0	76.7	75.8	76.5
1988	79.2	74.8	72.7	74.0	76.1	75.0	73.7
1989	101.0	102.0	94.2	99.5	98.6	96.9	90.6
1990	86.5	101.0	104.0	96.0	96.0	99.5	99.7
1991	116.0	110.0	107.0	106.0	106.0	104.0	107.1
1992	92.6	89.1	83.5	71.2	71.2	67.8	70.4
1993	92.6	86.5	77.3	76.6	71.9	86.1	88.0
1994	79.7	76.3	78.1	73.2	75.5	76.4	75.0
1995	101.1	99.6	94.3	99.6	99.6	97.9	104.0
1996	116.0	122.0	130.0	126.0	134.0	141.0	139.3
1997	138.0	145.0	142.0	149.0	153.0	159.0	159.0
1998	86.4	95.2	91.7	90.8	89.1	101.0	104.0
1999	116.0	120.0	130.0	128.0	124.0	123.0	124.1
2000	105.0	106.0	105.0	105.0	105.0	102.0	98.0
2001	80.4	66.4	58.6	56.1	56.5	55.5	58.2
2002	100.0	102.0	97.3	96.4	98.2	100.0	103.8
2003	80.5	75.6	74.9	85.3	90.2	89.3	87.7
2004	103.0	100.0	92.9	84.2	79.5	85.1	83.0
2005	85.6	82.4	70.7	73.8	74.7	79.8	81.3
2006	101.0	111.0	107.0	107.0	110.0	111.0	114.7
2007	105.0	101.0	100.0	100.0	99.1	96.4	95.7
2008	102.0	103.0	103.0	101.0	97.3	98.2	99.2
2009	94.7	92.9	86.2	92.0	91.1	92.0	90.2
2010	88.5	79.2	71.8	69.7	70.9	74.0	84.7
2011	104.0	110.0	109.0	117.0	128.0	141.0	137.0
2012	86.0	91.2	98.8	112.9	120.0	117.8	129.4
2013	102.5	92.0	89.7	91.1	92.4	93.9	97.7
2014	96.1	80.0	102.1	104.9	109.6	107.7	108.1
2015	102.6	103.8	91.7	95.9	86.5	86.0	83.7
2016	94.1	95.2	102.9	104.6	111.8	100.0	97.6
2017	96.6	93.4	108.8	130.8	136.9	141.9	137.1
Minimum	79.2	66.4	58.6	56.1	56.5	55.5	58.2
Median	96.8	95.2	97.3	98.6	98.2	98.2	97.7
Maximum	138.0	145.0	142.0	149.0	153.0	159.0	159.0

V - RESERVOIR OPERATION

General

During the 2016-17 Operating Year, the Canadian Storage operated in a manner consistent with DOP17 as modified by Entity or Supplemental Operating Agreements listed in Section III. Libby was operated consistently with the LCA, including the LOP, U.S. requirements for power, and U.S. Fish and Wildlife Service's 2006 Biological Opinion (BiOp), as clarified, and the National Oceanic and Atmospheric Administration's National Marine Fisheries Service's (NOAA Fisheries') 2010 and 2014 Supplemental BiOp for operation and maintenance of the FCRPS.

The water supply during the 2016-17 Operating Year was above average, referencing the 1981-2010 period of record. The actual runoff for the overall Columbia basin (U.S. and Canada combined) measured at The Dalles, OR, for January through July 2017 was 135 percent of normal.

For the period 01 August 2016 through 30 September 2017, the CRTOC executed two operating agreements. The first agreement was the Arrow Summer Storage agreement effective for the period 23 July 2016 through 15 August 2016, impacting Keenleyside operations (note: there was not an Arrow Summer Storage agreement in 2017). The second was the Nonpower Uses Agreement (NPU), effective for the period 01 December 2016 through 31 July 2017that impacted Mica and Keenleyside operations.

Canadian Storage Operation

At the beginning of the 2016-17 Operating Year (1 August 2016), actual Canadian Storage provided under Article II of the CRT (Canadian Storage) was at 15.5 km^3 (12.6 Maf) or 81.2 percent full. Canadian Storage drafted to a minimum of 3.7 km^3 (3.0 Maf), or 19.6 percent full in 31 March 2017. The composite Canadian Storage refilled to 18.5 km^3 (15.0 Maf), or 96.6 percent full, at the end of the Operating Year, 31 July 2017.

The composite Canadian Storage operation was consistent with the DOP TSR for the 2016-17 Operating Year, as modified by Entity or Supplemental Operating Agreements such as the STLA and NPU. During August 2016 through October 2016 and again during August 2017 through

the end of this reporting period, the TSR reflected the coordinated system being in proportional draft.

As specified in the DOP, the release of Canadian Storage is made effective at the Canada-U.S. border. Accordingly, releases from individual Canadian projects can vary from the release required by the DOP TSR plus Supplemental Operating Agreements, as long as this variance does not impact the ability of the Canadian system to deliver the sum of CRT-specified outflows or exceed the upper rule curves for CRT reservoirs. Variances from the TSR project target storage operation are accumulated in respective Flex accounts.

An overrun in a Flex account occurs when actual project releases are greater (contents are lower) than those specified by the TSR. Conversely, an underrun occurs when actual project releases are less (contents are higher) than those specified by the TSR. Flex accounts for Mica, Revelstoke, Keenleyside, and Duncan are balanced at all times (i.e., sum to zero) to ensure that neither underruns nor overruns impact the total CRT release required at the Canadian-U.S. border. The terms “underrun and overrun” are used in the description of Mica operations below.

Mica

At the start of the Operating Year on 01 August 2016, Kinbasket level was 751.58 meters (m) (2,465.8 feet, ft). This was 2.80 m (9.2 ft) below the normal full pool elevation. Mica is normally operated as required to meet system requirements and for the reporting period, Kinbasket levels were generally above average (see Chart 5) due to above normal runoff conditions and system constraints.

The fall of 2016 was significantly wetter than normal. This caused the reservoir to refill in Oct/Nov to reach a second peak level in 2016 of 752.83 m (2,469.9 ft), 1.55 m (5.1 ft) below full pool, on 16 November 2016. The winter of 2016/2017 was significantly colder than normal across the province. As a result of low temperatures and high system loads, Columbia Basin generation ran much harder than normal. This caused the reservoir to draft quickly across December through February approaching near average levels by spring 2017. In 2017, the minimum level reached was of 728.72 m (2,390.8 ft) on 04 May 2017, about 2.74 m (9 ft) above average.

Reservoir inflows for the period February to July 2017 were about 112 percent of average. Due to above average inflows and low electricity demands in the spring, the reservoir filled from

May to August to reach a maximum of 752.19 m (2,467.8 ft) on 19 August 2017, 2.19 m (7.2 ft) below normal full pool.

Inflow into Kinbasket was 97 percent of average over the period August to December 2016. Over this same period, the Mica outflow varied from a monthly average high of about 1,048 m^3/s (37.0 kcfs) in December 2016 to a monthly average low of about 235 m^3/s (8.3 kcfs) in October 2016. Inflows into Kinbasket were about 110 percent of normal over the period January to July 2017. The Mica discharge over this same period varied from a monthly average high of 1,169 m^3/s (41.3 kcfs) in January to a monthly average low of 136 m^3/s (4.8 kcfs) in June.

Mica had a Treaty underrun of 1.7 km^3 (683.9 ksfd) on 31 July 2016. The maximum underrun for the operating period was 3.9 km^3 (1,576.8 ksfd) on 30 November 2016, and the maximum overrun was 1.3 km^3 (540.7 ksfd) on 19 May 2017.

For the reporting period, NTSA water was released and stored by both parties into their respective accounts. In 2016, both BPA and B.C. Hydro filled their Active accounts to near full in October 2016. During the same period, the parties also stored into their respective Recallable accounts. Storage from the Recallable accounts was returned from 24 December 2016 through 06 January 2017.

Releases from the non-treaty accounts were exercised from late December through early February 2017 followed by relatively significant amount of storage from mid-February to the end of March 2017. By the end of March 2017, both B.C. Hydro and BPA's non-treaty accounts were refilled to 99.9 and 99.5 percent full. There has been no activity since until late July when these accounts were drafted across August. By the end of August 2017, both B.C. Hydro and BPA's non-treaty accounts were drafted to 71.8 and 67.7 percent full.

Revelstoke

Revelstoke Reservoir levels fluctuate throughout the day in response to a number of factors, including system electricity demand. Revelstoke Reservoir is normally operated between 571.50 m (1,875 ft) and 573.02 m (1,880 ft), but may be operated lower for brief periods during unusual conditions. During the spring freshet and winter peak load periods, it is common to have frequent daily fluctuations of the reservoir within about 1.52 m (5 ft) of full pool in response to weather patterns and inflow levels. During the 2016/2017 Operating Year, Revelstoke Reservoir remained within its normal operating range.

Keenleyside

Arrow reached a maximum level of 437.24 m (1,434.5 ft), or 2.90 m (9.5 ft) below full pool, on 10 June 2016. Arrow releases are regulated under the Columbia River Treaty and its supplemental operating agreements. Under dry conditions, more Treaty water is released from Arrow Lakes Reservoir according to the principles of proportional draft under the Columbia River Treaty. This operation resulted in high discharges from Keenleyside across July through September 2016 and produced correspondingly low summer levels. Arrow levels reached 430.96 m and 427.88 m (1,413.9 ft and 1,403.8 ft) by 31 August and 30 September 2016, respectively.

With the arrival of heavy rain storms in the fall (October – November 2016), the coordinated system went on to refill resulting in significantly reduced discharges from Arrow to as low as 142 m^3/s (5.0 kcfs) in November and 283 m^3/s (10.0 kcfs) in October. Arrow storage subsequently refilled to slightly above average levels by 31 December 2016 (Chart 6). Arrow then went on to draft across the winter to reach its minimum level of 427.15 m (1,401.4 ft) on 04 February 2017. By comparison, in the previous year, Arrow reached a minimum level of 424.13 m (1,391.5 ft) on 31 January 2016.

After reaching its minimum level in February 2017, the reservoir refilled to above normal for much of the Operating Year. This is due to a wetter than normal spring and above normal snowpack in the Columbia Basin. The runoff forecast for the entire Columbia Basin forecast at The Dalles was 125 percent of normal for April through August 2017.

Arrow reached a maximum level of 439.58 m (1,442.2 ft), or 0.55 m (1.8 ft) below full pool, on 27 July 2017. This is about 2.35 m (7.7 ft) above the 2016 maximum level. Since then, Arrow drafted across the summer to reach about 437.24 m (1,434.5 ft) on 31 August 2017 and 434.61 m (1,425.9 ft) on 30 September 2017. This is about 6.10 – 7.62 m (20.0 – 25.0 ft) higher than these times last year.

Local inflow into Arrow was 105 percent of average over the period August - December 2016. The Keenleyside discharge varied from a monthly average high of 1,648 m^3/s (58.2 kcfs) in August to a monthly average low of 184 m^3/s (6.5 kcfs) in November. Local inflow into Arrow was 108 percent of normal over the period January - July 2017. Outflow over this same period varied from a monthly average low of 589 m^3/s (20.8 kcfs) in April to a monthly average high of 2,061 m^3/s (72.8 kcfs) in January.

The CRTOC negotiated a Nonpower Uses Agreement for 2016-17 to manage Canadian and U.S. fisheries needs. In January 2017, Arrow Treaty flows were reduced to enable 1.2 km^3 (504 ksfd, 1 Maf) of Flow Augmentation storage as specified under the NPU. Under the provisions of the Water Use Plan (WUP) monitoring requirements, there were no provisions for whitefish protection flows in 2017. Additional provisions under the NPU maintained Keenleyside discharges during April - June 2017 at or above 481 m^3/s (17.0 kcfs) to protect rainbow trout spawning downstream of Keenleyside Dam. All of the water stored for Flow Augmentation under the NPU was released, for U.S. salmon migration, in July 2017.

Under terms of the STLA, B.C. Hydro exercised storage and release from this account in the reporting period. In August 2016, B.C. Hydro drafted about 0.2 km^3 (84 ksfd) and stored about 0.3 km^3 (126 ksfd) in October 2016. In December through early February 2017, B.C. Hydro exercised 0.7 km^3 (294 ksfd) of STLA provisional draft followed by a storage of 0.6 km^3 (252 ksfd) in the second half of February through the end of March 2017. By 31 March 2017, the account balance was brought to zero. There was no activity until 08 July - 11 August 2017 and 26-31 August 2017 when B.C. Hydro released for a total of 0.5 km^3 (210 ksfd) under STLA.

Duncan

Operation of Duncan during the 2016-17 Operating Year (refer to Chart 7) followed all Treaty requirements and implemented the operational constraints agreed upon in the Duncan WUP and ordered in the Water License Order (issued on 21 December 2007) except when variance were requested and granted.

Duncan Reservoir peaked at 576.47 m (1,891.3 ft), 0.21 m (0.7 ft) below full, on 08 August 2016. Duncan Dam discharges were adjusted across August to target the summer recreation level of 575.46 m (1,888.0 ft) between 10 August 2016 and Labour Day.

Starting 06 September 2016, Duncan discharges were increased to maintain flows in the Duncan River below the Lardeau River confluence (DRL) gauging station at 249 m^3/s (8.8 kcfs) maximum, to facilitate drafting of the reservoir prior to the start of the kokanee and whitefish spawning downstream of Duncan. Discharges were reduced on 26 September 2016 to target kokanee spawning flows of 74 m^3/s (2.6 kcfs) minimum at DRL and held this discharge until early December 2016. After the kokanee spawning flow period, Duncan Dam increased

discharge to target 249 m^3/s (8.8 kcfs) maximum from early December 2016 through February 2017, to facilitate drafting of the reservoir to meet the end-of-month Treaty FRM targets.

As in most years, the reservoir was drafted to near empty in late April. Duncan reached its minimum level, 547.30 m (1,795.6 ft) on 11 April 2017. By comparison, the reservoir reached a similar minimum level of 547.21 m (1,795.3 ft) on 08 April 2016.

The reservoir discharge was reduced to its minimum of 2.8 m^3/s (0.1 kcfs) in late-May to initiate reservoir refill and reduce flood risk on Kootenay Lake. Releases from Duncan were held at minimum until early July, when discharges were gradually increased to manage the rate of reservoir refill. In 2017, Duncan refilled to a maximum of 576.50 m (1,891.4 ft), 0.18 m (0.6 ft) below full pool on 13 August 2017. Duncan discharges were increased during August to facilitate drafting the reservoir to reach the summer recreation target of 575.46 m (1,888.0 ft) between 10 August and Labour Day as per the Duncan Water Use Plan Order.

Libby

The operation of Libby Dam and Lake Koocanusa is shown in Chart 8 for the period 01 August 2016 through 30 September 2017. Lake Koocanusa ended July 2016 at elevation 745.82 m (2,446.9 ft), 3.69 m (12.1 ft) below full pool. The project was drafted to elevation 745.72 m (2,446.6 ft) at the end of August 2016, with outflows held constant for the month at 198 m^3/s (7.0 kcfs), the bull trout minimum. The Kootenai Tribe of Idaho (KTOI) requested low flows in the fall of 2016 to assist with the continuing habitat restoration work in the Kootenai River, as in previous years. For the month of September 2016, releases averaged 178 m^3/s (6.3 kcfs) and the project ended September at elevation 745.24 m (2,445.0 ft). The final April-August 2016 inflow volume to the project was 6.8 km^3 (5.5 Maf), or 93 percent of the 30-year normal (1981-2010).

In October, releases were reduced and held to 113 m^3/s (4.0 kcfs), the project minimum outflow. Heavy precipitation in October resulted in high inflows and Libby Dam ended the month higher than normal at elevation 747.64 m (2,452.9 ft). Outflow was increased in November to target end-of-year FRM requirements. The December 2016 water supply forecast (WSF) for the April-August 2017 runoff period was initially estimated at 11.0 km^3 (8.9 Maf), or 152 percent of average, setting the 31 December FRM elevation to 734.87 m (2,411.0 ft). The Canadian Entity had expressed concerns that the high October precipitation totals were overly influencing the forecasted volumes developed by the regression equations. Subsequently, the U.S. Entity agreed to

review the forecast result and input parameters. Upon review, the Entities agreed to limit the October precipitation input to the Libby water supply forecast to two standard deviations from the mean. This reduced the April-August water supply forecast for the month December from 11.0 km^3 (8.9 Maf) to 8.6 km^3 (7.0 Maf). This adjustment affected subsequent forecasts that set FRM targets for Libby Dam during the remainder of the drawdown period from December through April. Releases were kept at powerhouse capacity from 09 November until 29 December to reach the end of December FRM target of 734.87 m (2,411.0 ft). The December FRM elevation was reached at the end of the month and releases were adjusted to target the end of January FRM elevation of 730.36 m (2,396.2 ft). Outflow for November-December averaged 637 m^3/s (22.5 kcfs). The April-August water supply forecast for the month of January was 8.5 km^3 (6.9 Maf).

Libby's April-August water supply forecast for the month of February decreased to 6.9 km^3 (5.6 Maf), or 95 percent of average, due to low precipitation totals in December and January. Releases averaged 119 m^3/s (4.2 kcfs) in February resulting in an end-of-month elevation 11.73 m (38.5 ft) below the FRM target. The month of February experienced record precipitation and the snowpack increased from 80 to 104 percent of average between February and March.

The March WSF for April-August increased to 8.4 km^3 (6.8 Maf, 115 percent of average) with a corresponding end-of-month FRM target of 726.06 m (2,382.1 ft), 3.99 m (13.1 ft) lower than the first-of-month elevation for Lake Koocanusa. Releases were held at 113 m^3/s (4.0 kcfs) until 18 March for habitat work downstream of Libby Dam. Once the habitat work was finished, releases were increased to reach the end-of-month FRM target. However, releasing water through the powerhouse alone would not draft Libby to the March FRM target. Per the Libby Dam Water Control Manual (WCM), releases were held at powerhouse capacity after a risk assessment showed no justification to spill to meet the target. Lake Koocanusa was drafted to elevation 727.13 m (2,385.6 ft) on 31 March.

The water supply forecasts continued increasing through May due to well above average snow accumulation. The April WSF increased to 9.5 km^3 (7.7 Maf), or 130 percent of average, with an end-of-month FRM target of 708.78 m (2,325.4 ft). After the Canadian Entity expressed concern about flooding on Kootenay Lake, the U.S. and Canadian Entities coordinated operations for the Kootenai Basin. It became evident that Libby Dam was not going to reach its end-of-month FRM target by releasing water only through the powerhouse. The USACE Seattle District office performed several risk assessments to verify if spilling would be a prudent

operation. Each assessment showed that spilling from Libby Dam would increase the flood risk at Bonners Ferry, ID and Kootenay Lake so releases were kept at powerhouse capacity through the end of the month with the 30 April elevation at 719.79 m (2,361.5 ft).

The May WSF was 10.1 km^3 (8.2 Maf), or 139 percent of average. Libby outflow was held to powerhouse capacity at the request of the Canadian Entity despite the fact that the VarQ flow for May was 450 m^3/s (15.9 kcfs). Releases were held at powerhouse capacity through the first several days of May until it was determined that the high releases would increase flood risk at Bonners Ferry, ID by putting additional water above the VarQ flow into Kootenay Lake. On 05 May, Libby Dam reached its minimum elevation for the year of 719.15 m (2,359.4 ft). On 15 May, Libby began to release the sturgeon volume, 1.5 km^3 (1.2 Maf) set by the May WSF, with releases increasing to 685 m^3/s (24.2 kcfs) or powerhouse capacity for approximately 7 days, followed by 510 m^3/s (18.0 kcfs) for 11 days. In 2017, the double pulse operation was implemented to first mimic the peak of the tributaries (15-21 May) with a second peak at powerhouse capacity for 9 days (03-11 June) to mimic the peak inflows seen at Libby Dam in early June. Releases for the second pulse were gradually ramped down to 396 m^3/s (14.0 kcfs) as the sturgeon volume was expended on 26 June. Lake Koocanusa ended the month of June at elevation 743.56 m (2,439.5 ft).

The operation for the rest of the summer, July through August, was to try to refill Libby in so far as possible and meet the 746.46 m (2,449.0 ft) target by the end of September, as required in the NOAA Fisheries' BiOp and coordinated through the Technical Management Team (TMT). The target elevation of 746.46 m (2,449.0 ft) is based on The Dalles water supply forecast being above the 20th percentile runoff volume (below 20th percentile the requirement would be to draft to 743.41 m, or 2,439.0 ft). Libby reached its peak elevation for the summer on 02 August, 746.36 m (2,448.7 ft), which was 3.14 m (10.3 ft) below full pool. Even though the winter was one of the coldest and wettest winters in 30 years, the summer precipitation virtually dried up after 27 June. The West Glacier precipitation gage did not have more than a few traces of rain for 64 days between (27 June and 31 August). This gage is generally considered one of the better indicators of inflows into Libby Dam. Due to low inflows, the project kept releases to the minimum bull trout flow of 255 m^3/s (9.0 kcfs) through August then ramped down to 170 m^3/s (6.0 kcfs), the minimum bull trout flow for September. Libby elevations were 745.27 m (2,445.1 ft) and 744.47 m (2,442.5 ft) at the end of August and September, respectively. The 170 m^3/s

(6.0 kcfs) outflow in September was also the requested release from Libby to help with the in-stream habitat work for the Kootenai Tribe of Idaho. Libby held this minimum release through the end of September.

Kootenay Lake

Kootenay Lake is operated (refer to Chart 9) to meet numerous interests, including provision of meeting maximum levels under the IJC and minimum flow targets in the Kootenay River at the Brilliant Dam. Operations target a minimum Brilliant flow of 510 m^3/s (18.0 kcfs) during the period December through September and 453 m^3/s (16.0 kcfs) during October through November.

On 02 July 2016, Kootenay Lake (at Nelson) was drafted to 531.36 m (1,743.32 ft), at which point the IJC compliance gauge switched from Queens Bay to Nelson, and the lake was maintained near 531.27 m (1,743.0 ft) through August. Kootenay Lake continued to pass inflows through September and early October to provide fish flows downstream. Periodically, Brilliant discharges fell below the minimum target flow of 453 m^3/s (16.0 kcfs) in October due to low inflows. Following the summer drought, the fall storms came in late October and November setting all-time record high rainfall and unprecedented high inflows into Kootenay Lake. Lake discharges were increased to its maximum possible in November to control refill of the lake to below its maximum permissible IJC level.

From late December through mid-March 2017, the lake was drafted to accommodate a Brilliant Expansion plant outage in January. Further, as is normal, the IJC maximum level begins to lower linearly towards 531.57 m (1,744.0 ft) by 01 February and 531.08 m (1,742.4 ft) by 01 March. Kootenay Lake reached a minimum level of 530.02 m (1,738.9 ft) on 13 March 2017.

Following a relatively dry winter, the spring was exceedingly wet, setting new record high precipitation in March and April 2017. This caused Kootenay Lake levels to exceed the IJC maximum level and its historical maximum during this period although discharges were proactively brought to maximum flow rates through Grohman Narrows starting 01 March 2017.

Despite maximum outflows from the lake, the Kootenay Lake level remained above the IJC Order reference level from about mid-March until the declaration of Spring Rise on 25 April

2017. During this time, the Corra Linn and Kootenay Canal projects were operated to discharge maximum possible ("free fall" or "free flow" conditions), which maintained compliance with the IJC Order requirements.

The International Kootenay Lake Board of Control, after consultation with FortisBC, declared the Commencement of Spring Rise for Kootenay Lake on 25 April 2017. Following this declaration, the Corra Linn and Kootenay Canal projects continued to pass maximum discharge (free flow), limited only by the natural flow restriction of Grohman Narrows, until early July 2017. Due to elevated flood risk on Kootenay Lake this year, the U.S. and Canadian section of the Operating Committee worked closely to coordinate flows from Libby early in the spring to reduce peak levels on Kootenay Lake in June. To further aid in lowering Kootenay Lake levels, Duncan flows were reduced to minimum outflow as is normal every spring freshet. These efforts resulted in Kootenay Lake reaching a maximum level of 533.74 m (1,751.1 ft) on 09 June 2017, just 0.27 m (0.9 ft) below the onset of flood damages. By comparison, in 2016, the peak level was 532.82 m (1,748.1 ft) on 27 May 2016. Discharge from Kootenay Lake peaked at 2,280 m^3/s (80.5 kcfs) on 05 June 2017 while the Kootenay River discharge at Brilliant peaked at 2,894 m^3/s (102.2 kcfs) on 02 June 2017.

On 18 July 2017, Kootenay lake was drafted to 531.36 m (1,743.32 ft), at which point the IJC compliance gauge switched from Queens Bay to Nelson, and the lake was maintained near 531.27 m (1,743.0 ft) through August.

VI - FLOOD RISK MANAGEMENT AND POWER ACCOMPLISHMENTS

General

During the period covered by this report, the Duncan, Arrow, and Kinbasket reservoirs were operated for power, FRM, and other benefits in accordance with the CRT and operating plans and agreements described in Section III, Operating Agreements. Consistent with all DOPs prepared since the installation of generation at Mica, the 2016-2017 DOP was designed to achieve optimum power generation onsite in Canada, and downstream in Canada and the U.S., in accordance with paragraph 7 of Annex A of the CRT.

Power operations for the whole of Canadian Storage are determined by the ORCs, Mica/Keenleyside project operating criteria, and non-power constraints as implemented in the TSR. The ORC calculation includes the VRCs which are dependent upon the water supply in any given water year, and the VRC is updated each month with the development of a new water supply forecast. The monthly VRC calculations for Mica, Keenleyside, and Duncan are shown in Tables 2 and 4, and Tables 2M and 4M. The calculations for Libby VRCs are shown in Tables 5 and 5M. Libby VRCs are used in the preparation of the TSR.

The Libby December 2016 water supply forecast for April-August 2017 runoff was 11.0 km^3 (8.9 Maf), or 152 percent of average (based on the 1981-2010 inflow). Based on this forecast, the recommended draft for Lake Koocanusa was 2.5 km^3 (2.0 Maf), to elevation 734.87 m (2,411.0 ft) on 31 December. Libby was operated to its VarQ FRM storage reservation diagram and began refill in early May according to the Initial Controlled Flow (ICF) date.

Flood Risk Management

Overall, the 2017 water supply for the Columbia Basin was well above average. The Snake River Basin's April to August unregulated runoff at Lower Granite Dam was 142 percent of average. The unregulated runoff in all of the other Columbia River Basin sub-basins were within 106 to 119 percent of average. All combined, the unregulated April-August volume at The Dalles of 134.8 km^3 (109.3 Maf) was 125 percent of the 1981-2010 NWRFC normal. During the

drawdown period, the reservoir system, including the Columbia River Treaty projects, is required to draft for FRM in preparation for the spring rise. Inflow forecasts and reservoir regulation modeling were done throughout the winter and spring. Mica, Keenleyside, and Duncan were operated according to the FRM requirements of the May 2003 FCOP. Libby was operated to its VarQ Storage Reservation Diagram and accompanying rules. The unregulated peak flow (based on the USACE ResSim program output) at The Dalles, Oregon, shown on Chart 13, was estimated at 20,116 m^3/s (710.4 kcfs) on 04 June 2017, and a regulated daily peak flow for April through July of 12,465 m^3/s (440.2 kcfs) occurred on 04 June 2017 as measured at The Dalles Dam. The regulated peak stage[6] at Vancouver, Washington, (VAPW) was observed at 5.24 m (17.2 ft) on 01 April 2017 while the flood stage is 4.88 m (16.0 ft). The peak unregulated stage at Vancouver was estimated at 7.28 m (23.9 ft) on 03 June 2017.

For the 2016-2017 Operating Year, the Canadian Entity elected to operate Mica and Keenleyside to the FRM storage allocations of 4.4 km^3 (3.6 Maf) maximum draft at Arrow and 5.03 km^3 (4.08 Maf) maximum draft at Kinbasket, as allowed under the 2003 FCOP. This allocation was first incorporated in the AOP for 2006-2007.

Computations of the ICF for system FRM operation were made in accordance with the Treaty FCOP. For 2017, the computed ICFs at The Dalles, based on the various first-of-month water supply forecasts, are as follows:

Initial Controlled Flow at The Dalles

Based on	kcfs	m^3/s
January Forecast	298	8,438
February Forecast	308	8,722
March Forecast	338	9,571
April Forecast	368	10,421
May Forecast	411	11,638

[6] The peak observed regulated stage at the Vancouver gage (VAPW) during the reporting period was 5.36 m (17.6 ft) which occurred on 30 March 2017 (just outside the traditional Apr-Jul freshet) due to high flows on both the Columbia and Willamette Rivers

Refill at the projects can commence relative to the date[7] when the unregulated flow at The Dalles is expected to equal or exceed the ICF (ICF date). For WY 2017, the ICF date was declared as of 04 May based on a projection that the unregulated flow would consistently remain above the ICF. The FRM objectives at The Dalles were for regulated flows to stay within a specified range of daily average and instantaneous maximum flows, and for the Grand Coulee dam elevation to be below a set end-of-month target. As mentioned earlier, the observed daily peak flow at The Dalles this year was 12,465 m^3/s (440.2 kcfs) occurring on 04 June 2017. Table 6 shows the data used for the April ICF computation.

Canadian Entitlement and Downstream Power Benefits

From 01 August 2016 through 30 September 2017, the U.S. Entity delivered the CE to downstream power benefits from the operation of Canadian Storage to the Canadian Entity, at existing points of interconnection on the Canadian-U.S. border. The amounts returned, before deductions for transmission losses and scheduling adjustments, are listed in Section III Operating Arrangements of this report, under the heading Canadian Entitlement.

For the period 01 August 2016 through 31 July 2017, the CE amount, before deducting transmission losses, was 484.0 aMW of energy, scheduled at rates up to 1,333 MW capacity. From 01 August 2017 through 30 September 2017, the amount, before deducting transmission losses, was 475.0 aMW of energy, scheduled at rates up to 1,304 MW capacity. The CE obligation was determined by the 2015-2017 and 2017-2018 AOP/DDPBs.

During the course of the 2016-2017 Operating Year, there was one CE delivery curtailment event. On 14 December 2016, there was a two hour event totaling 10 MWh. The 10 MWh was successfully redelivered on 17 December 2016. The following Figure 5 shows the historic CE amounts from the DDPB studies as compared to the estimated amount under the 1964 Canadian Entitlement Exchange Agreement (CEEA).

[7] Per the FCOP, projects begin refilling at different times before the ICF Date. For example Libby can start refill 10 days before the declared ICF date, Mica 5 days before and Arrow 2 days before.

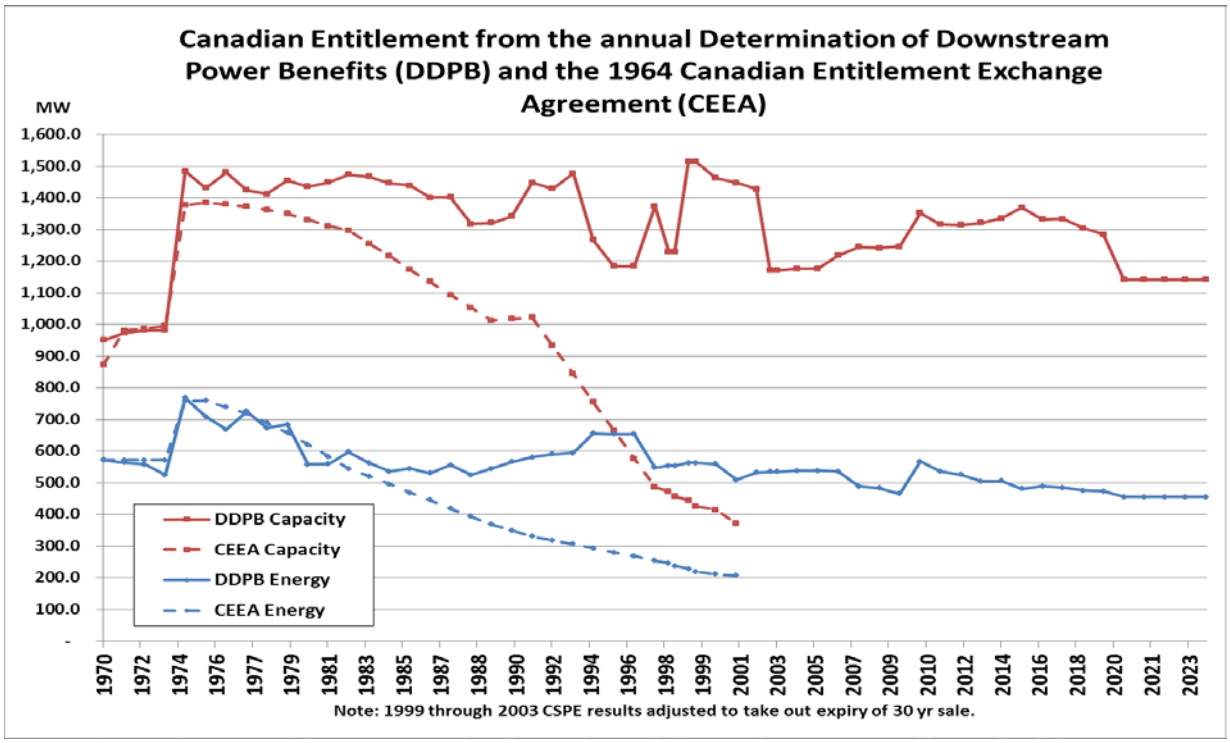


Figure 5: Canadian Entitlements: Agreed CEEA Amounts vs. DDPB Amounts

The CEEA amounts for the CE were based on forecast load growth that was much higher than the subsequent actual load growth. This load growth difference is the main reason for the large difference in the CE between the historic DDPBs (agreed to annually for the 6th succeeding year) and the CE Exchange Agreement amounts (agreed to in 1964).

In accordance with the Canadian Entitlement Allocation Extension Agreement, dated April 1997, the non-federal downstream U.S. projects delivered to BPA their portion of the CE (27.5 percent), and the U.S. Entity granted permission for the non-federal downstream U.S. parties to make use of the U.S. one-half share of the CRT downstream power benefits (U.S. Entitlement).

2024 Review

In December 2013, the U.S. Entity transmitted "The U.S. Entity Regional Recommendation for the Future of the Columbia River Treaty after 2024," to the U.S. Department of State. The U.S. Entity's Recommendation marked the successful conclusion of the regional engagement chapter of the U.S. Entity's Treaty Review effort, and the beginning of the formal review by the U.S. Government. In the late summer of 2015, the U.S. Department of State assigned a lead negotiator to the Columbia River Treaty; the following year, in the fall of 2016, the

Administration completed its authorization to allow the U.S. Department of State to enter into formal negotiations with Canada.

The Government of B.C. engaged in a parallel Treaty review process and public consultation. In March 2014, following extensive First Nations consultation and community engagement, and after conducting a number of technical studies, the Government of British Columbia announced it would like to continue the Columbia River Treaty and seek improvements within the existing framework and published the "B.C. Decision and Guiding Principles". This decision is supported by the Federal Government of Canada.

While the Government of Canada continued to work toward achieving their mandate to begin negotiations, the U.S. lead negotiator conducted discussions and meetings with regional sovereign states and tribes, stakeholders, and federal agencies from the U.S. with the intent of providing a forum for conducting modeling to inform future negotiations. Called the Collaborative Modeling Workgroup, this group was expanded in late fall of 2016 to add representatives from Canada, including the Government of Canada, the Government of B.C., First Nations and stakeholders to further the joint understanding of technical aspects of potential Treaty modernization and conduct joint modeling. The U.S. and Canadian Entities, as part of their responsibility for Treaty implementation, held discussions and conducted joint modeling specific to post-2024 FRM and simplification of Treaty planning for power operations.

Power Generation and Other Accomplishments

Actual U.S. power benefits from the operation of Canadian Storage can only be roughly estimated. Canadian Storage has such a large impact on the operation of the U.S. system that its absence would significantly affect operating procedures, nonpower requirements, loads and resources, and market conditions, thus making any benefit analysis highly speculative.

The following Figure 6 shows a rough estimate of the average monthly impact of Canadian Storage on downstream U.S. hydro power generation during the 2016-17 Operating Year, based on the Pacific Northwest Coordination Agreement (PNCA) AER that includes flow and spill requirements for fishery objectives. The increase in average annual U.S. hydro power generation due to the operation of Canadian Storage, as measured by the PNCA AER, was 630 aMW. The

increase in hydro power generation occurred primarily in the winter months, December through March. No quantification of this benefit is provided in this report.

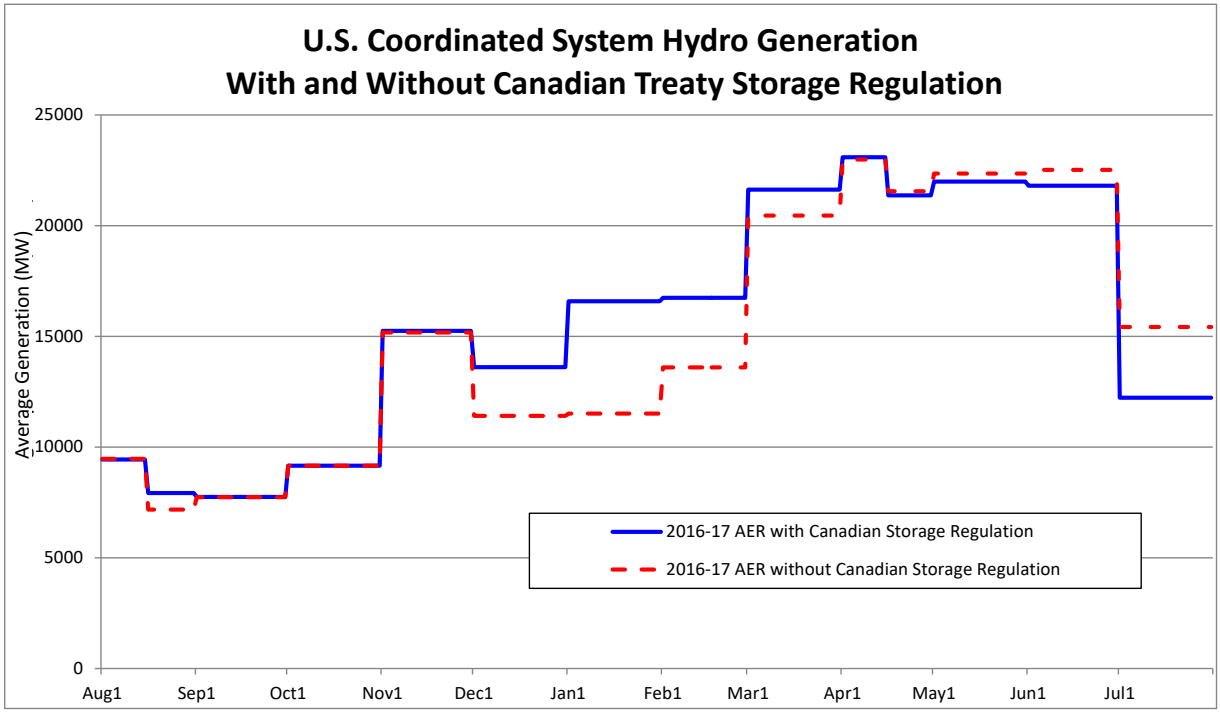


Figure 6: U.S. Coordinated System Hydro Generation

Treaty operating plans are designed to adapt to streamflow and water supply conditions that arise and evolve over the Operating Year. Operating Plans are implemented through the TSR model study which incorporates streamflows, water supply forecasts and operating parameters dependent on runoff conditions during the Operating Year, and which resets the specified Canadian Storage target twice a month and finalizes the target in the first TSR of the subsequent period. This report discusses conditions as realized for the 2016-17 Operating Year and describes the response of Canadian Storage to the actual inflows and water supply conditions which occurred over the year. The risk mitigation benefits associated with the Treaty's flexibility to adapt to the broad array of water conditions that were possible going into the water year are not addressed or quantified in this report.

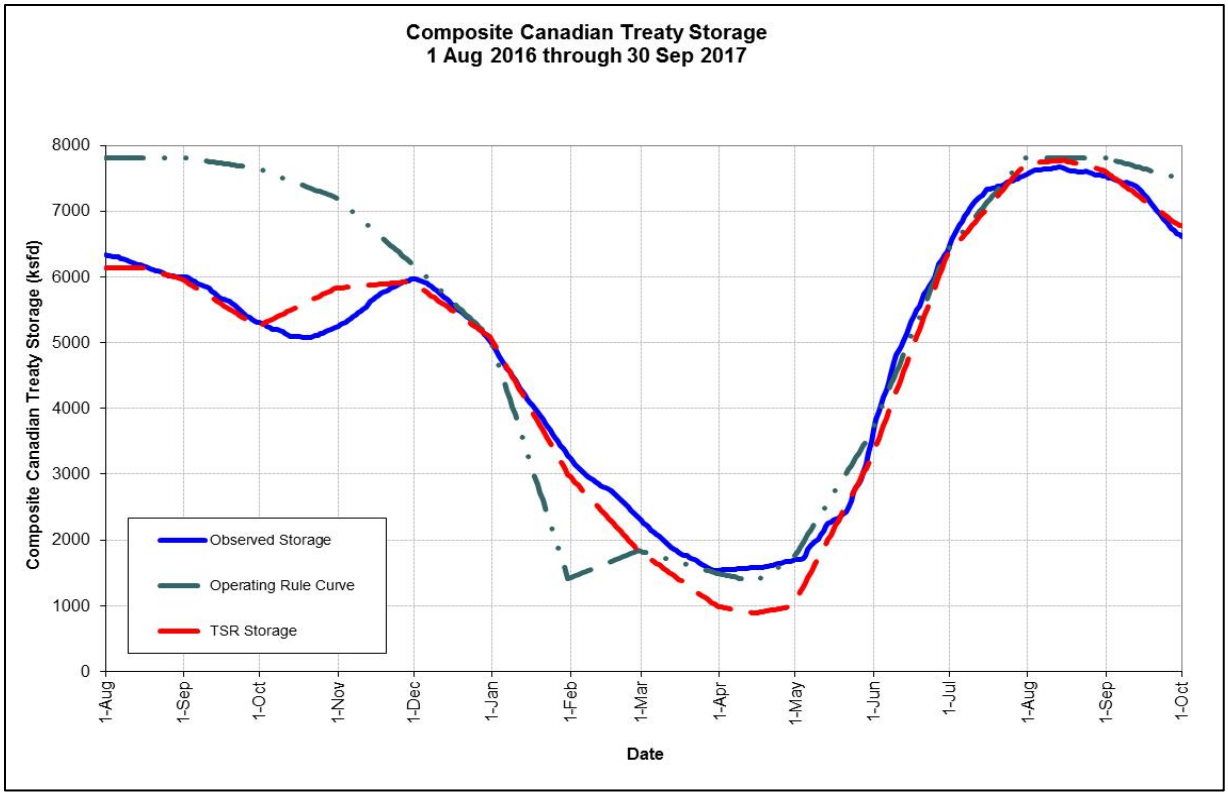


Figure 7: Composite Canadian Storage

Figure 7 compares the actual operation of the composite Canadian Storage to the results of the DOP TSR study. Canadian Storage operated in proportional draft mode during August 2016 through October 2016 and again during August 2017 through the end of this reporting period to meet Treaty firm loads. The STLA Arrow Provisional Account was drafted and filled as described in Section V between August 2016 and March 2017. By the end of March the account reached a zero balance relative to the TSR and remained there until early July 2017 when releases began. Under the 2016-2017 NPU agreement, the U.S. stored 1.2 km^3 (504 ksfd, 1 Maf) above the TSR for Flow Augmentation in January and maintained that balance until flow augmentation began to be forced out due to FRM operations. All Flow Augmentation was released by the end of July. Also under the NPU agreement, Treaty discharges from Keenleyside were set low during April through June to support trout spawning which contributed to Treaty Storage being above the TSR during that timeframe.

Figure 8 shows the difference in Keenleyside, plus Duncan regulated outflows in the DOP TSR, and the actual daily CRT outflows. The daily unregulated inflows are also shown for comparison purposes.

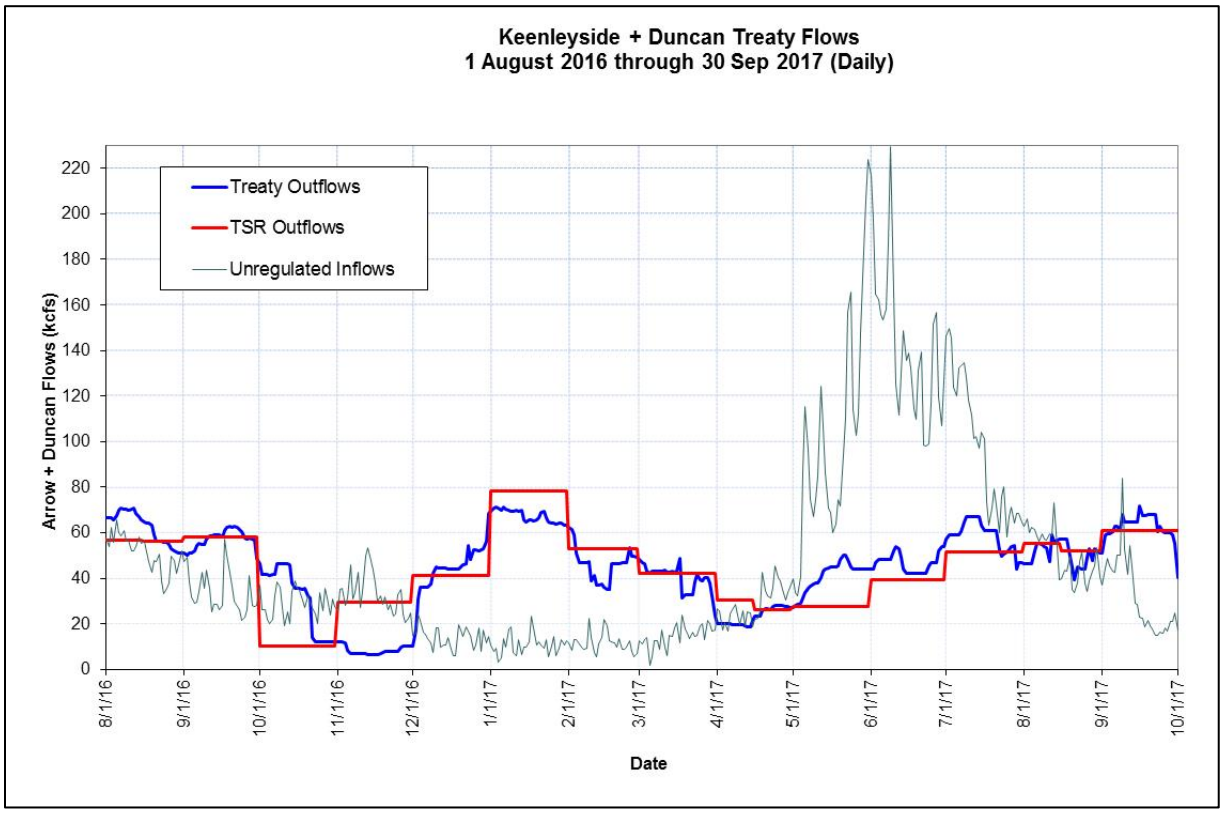


Figure 8: Keenleyside and Duncan Treaty Flows

Figure 9 summarizes the Treaty accounting including supplemental operating agreements throughout the year. Section I shows the difference for each period between the final TSR composite storage and the actual composite Canadian Storage, including the supplementary operating agreements. Section II shows the storage balance for each supplemental operating agreement as they were implemented. Section III shows how the TSR storage content varies over time due to updated forecasts, unexpected weather events, and other factors. The final TSR target results are not available until after-the-fact, resulting in some inadvertent storage, as shown in Section II, Line 9.

Summary of Treaty Storage Operations
July 2016 through September 2017

All units in KSFD	2016							2017										
I. Composite Treaty Storage (ksfd)	JUL	AU1	AU2	SEP	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
1)Treaty Storage Regulation (Final)	6133.6	6140.9	5970.9	5246.0	5826.6	5929.2	5092.5	2998.5	1836.1	994.9	887.1	992.5	3232.6	6329.0	7721.6	7773.9	7622.1	6775.9
2) Actual Treaty Content (w/SOA's)	6344.8	6179.4	5994.6	5307.1	5230.7	5960.6	5037.6	3289.9	2330.7	1530.9	1578.2	1685.6	3505.2	6388.3	7553.7	7653.3	7539.0	6636.4
3) % full (TSR Comp.Storage/7814.6)	78.5%	78.6%	76.4%	67.1%	74.5%	75.9%	65.2%	38.4%	23.5%	12.7%	11.3%	12.7%	41.4%	81.0%	98.8%	99.5%	97.5%	86.7%
4) Final deviation from TSR	**211.2**	**38.5**	**23.7**	**61.1**	**-595.9**	**31.4**	**-54.9**	**291.4**	**494.6**	**536.0**	**691.1**	**693.1**	**272.6**	**59.3**	**-167.9**	**-120.6**	**-83.1**	**-139.5**

II. Monthly Accounting of Supplemental Operating Agreements Content (ksfd)

	2016							2017										
Balance in each period	JUL	AU1	AU2	SEP	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
5) Short Term Libby Agreement (STLA)	0.0	-18.0	-84.0	-84.0	42.0	42.0	-14.0	-231.0	-175.0	0.0	0.0	0.0	0.0	0.0	-102.0	-168.0	-204.0	-162.0
6) Non Power Uses Flow (NPU) FA	0.0	0.0	0.0	0.0	0.0	0.0	17.0	504.0	504.0	504.0	504.0	504.0	504.0	175.0	0.0	0.0	0.0	0.0
7) Arrow Summer Shaping Agreement	211.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8) Total	211.2	-18.0	-84.0	-84.0	42.0	42.0	3.0	273.0	329.0	504.0	504.0	504.0	504.0	175.0	-102.0	-168.0	-204.0	-162.0
9. Inadvertent (Line 4 - Line 8)	**0.0**	**56.5**	**107.7**	**145.1**	**-637.9**	**-10.6**	**-57.9**	**18.4**	**165.6**	**32.0**	**187.1**	**189.1**	**-231.4**	**-115.7**	**-65.9**	**47.4**	**120.9**	**22.5**
									NPU avg Feb-Mar		NPU Shaping; inadvertent does not apply							

III. Summary of TSR Results (Final TSR in green)
Composite Treaty Storage TSR Content (ksfd)

	2016							2017										2017
TSR Date	JUL	AU1	AU2	SEP	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
5-Aug-16	**6133.6**	6136.2	6064.7	5463.1	4882.6	3803.0	3013.1	1750.7	1384.0	667.7	565.6	658.0	2634.4	5508.5	7381.8			
22-Aug-16		**6140.9**	6037.3	5360.4	4663.2	3603.3	2793.5	1549.7	1183.0	667.7	565.6	658.0	2634.4	5508.5	7381.8			
8-Sep-16			**5970.9**	5234.1	4527.9	3482.1	2655.7	1582.6	1215.9	667.7	565.6	658.0	2634.4	5508.5	7381.8			
22-Sep-16				5323.5	4634.4	3530.2	2712.6	1662.2	1295.5	703.7	601.6	694.1	2670.4	5544.6	7417.9			
6-Oct-16				**5246.0**	4565.8	3443.0	2619.9	1549.6	1182.8	703.7	601.6	694.1	2670.4	5544.6	7417.9			
19-Oct-16					5350.1	4535.5	3762.7	2236.0	1798.0	703.7	601.6	694.1	2670.4	5544.6	7417.9			
4-Nov-16					**5826.6**	5813.1	5036.6	2906.0	1838.5	833.3	731.2	823.7	2800.0	5674.2	7547.5			
18-Nov-16						5915.8	5092.5	3015.6	1838.5	956.3	854.3	946.7	2923.0	5797.2	7670.5			
9-Dec-16						**5929.2**	5092.5	3024.5	1435.6	965.3	863.2	955.7	2932.0	5806.0	7679.5			
20-Dec-16							5010.4	2935.3	1385.5	965.3	863.2	955.7	2932.0	5806.0	7679.5			
11-Jan-17							**5092.5**	2997.9	1460.3	965.3	873.0	979.0	3151.9	5903.5	7721.6			
24-Jan-17								3004.1	1469.4	965.3	870.9	977.7	3147.2	5888.5	7721.6			
9-Feb-17								**2998.5**	1836.1	989.1	889.0	985.6	3087.2	5700.2	7488.8			
21-Feb-17									1836.1	989.1	886.2	981.6	3064.5	5666.2	7437.5			
9-Mar-17									**1836.1**	994.9	892.4	988.9	2950.2	5684.0	7465.7			
22-Mar-17										994.9	931.6	1073.6	3012.8	5701.8	7442.0			
11-Apr-17										**994.9**	906.5	1049.2	3047.6	5839.1	7667.4			
21-Apr-17											**887.1**	999.2	3084.4	5841.4	7666.3			
9-May-17												**992.5**	3296.4	5967.1	7690.1			
23-May-17													3309.2	6250.4	7691.8			
9-Jun-17													**3232.6**	6400.6	7721.6			
21-Jun-17														6368.7	7721.6	7779.5	7799.1	
7-Jul-17														**6329.0**	7721.6	7779.2	7786.1	
20-Jul-17															7721.6	7779.2	7786.1	7499.5
4-Aug-17															**7721.6**	7775.2	7722.6	7231.0
22-Aug-17																**7773.9**	7682.2	6896.3
8-Sep-17																	**7622.1**	6776.0
21-Sep-17																		6775.9
																		6775.9
Proportional Draft Point (PDP)	3.425	4.485	4.557	4.605	2.978	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	2.967	3.735	3.100

Figure 9: Summary of Treaty Storage Operation

VII – TABLES

Table 1M (metric): Unregulated Runoff Volume Forecasts Cubic Kilometers

Most Probable 1-April through 31-August Forecasts in km^3

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.5	28.4	14.3	8.5	104.8
February	2.4	26.0	13.2	6.9	102.2
March	2.4	26.2	13.3	8.4	113.9
April	2.5	27.9	14.0	9.4	129.6
May	2.6	28.8	14.1	10.1	137.1
June	2.7	29.6	14.5	9.4	142.6
Actual	2.7	28.6	14.3	8.7	134.8

Table 1: Unregulated Runoff Volume Forecasts Million Acre-feet

Most Probable 1-April through 31-August Forecasts in Maf

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.0	23.0	11.6	6.9	84.9
February	2.0	21.1	10.7	5.6	82.8
March	1.9	21.2	10.8	6.8	92.3
April	2.0	22.6	11.3	7.7	105.0
May	2.1	23.3	11.4	8.2	111.1
June	2.2	24.0	11.8	7.6	115.6
Actual	2.2	23.2	11.6	7.0	109.3

Table 2M (metric): 2017 Mica Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			12.0	11.1	10.9	11.0	10.5	8.3
PROBABLE DATE-31JULY INFLOW, hm3	**		11990.3	11149.9	10874.2	11044.0	10477.6	8288.3
95% FORECAST ERROR FOR DATE, hm3			1802.7	1276.5	1113.4	1027.9	982.1	971.3
95% CONF.DATE-31JULY INFLOW, hm3	1/		10187.6	9873.4	9760.7	10016.0	9495.5	7317.0
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		10187.6					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		3875.4					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		2322.3					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		736.6					
JAN31 ORC, m	7/		736.6					
BASE ECC, m	8/	743.6						
LOWER LIMIT, m		733.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		9973.7	9666.0				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		3669.9	3717.2				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		2330.8	2685.7				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		736.6	737.6				
FEB28 ORC, m	7/		736.7	737.5				
BASE ECC, m	8/	737.5						
LOWER LIMIT, m		729.9						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		9729.2	9429.0	9516.7			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0			
MIN APR1-JUL31 OUTFLOW, hm3	4/		3442.4	3489.7	3442.4			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		2347.7	2695.2	2560.2			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		736.7	737.7	737.3			
MAR31 ORC, m	7/		736.7	737.6	737.3			
BASE ECC, m	8/	737.6						
LOWER LIMIT, m		729.7						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90.7	90.7	92.5	94.8		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		9219.8	8935.4	9018.9	9495.2		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		3222.2	3269.5	3222.2	3222.2		
VRC APR30 RESERVOIR CONTENT, hm3	5/		2636.9	2968.6	2837.8	2361.5		
VRC APR30 RESERVOIR CONTENT, METERS	6/		737.5	738.4	738.1	736.7		
APR30 ORC, m	7/		737.5	737.5	737.5	736.7		
BASE ECC, m	8/	737.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		7294.3	7069.3	7135.1	7522.0	7520.4	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0	85.0	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		2994.6	3041.9	2994.6	2994.6	2994.6	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		4334.8	4607.2	4494.1	4107.1	4108.8	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		742.2	742.9	742.6	741.5	741.5	
MAY31 ORC, m	7/		741.0	741.0	741.0	741.0	741.0	
BASE ECC, m	8/	741.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		3687.9	3574.2	3611.5	3806.1	3807.7	3702.4
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		453.1	453.1	468.2	453.1	453.1	453.1
MIN JUL1-JUL31 OUTFLOW, hm3	4/		1820.3	1828.4	1820.3	1820.3	1820.3	1820.3
VRC JUN30 RESERVOIR CONTENT, hm3	5/		6766.9	6888.8	6843.3	6648.7	6647.1	6752.4
VRC JUN30 RESERVOIR CONTENT, METERS	6/		748.4	748.7	748.6	748.1	748.1	748.3
JUN30 ORC, m	7/		748.1	748.1	748.1	748.1	748.1	748.1
BASE ECC, m	8/	748.1						
JUL 31 ORC, m			752.9	752.9	752.9	752.9	752.9	752.9

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (8634.54 hm3) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 2: 2017 Mica Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			9720.6	9039.3	8815.7	8953.4	8494.2	6719.4
PROBABLE DATE-31JULY INFLOW, KSFD	**		4900.8	4557.3	4444.6	4514.0	4282.5	3387.7
95% FORECAST ERROR FOR DATE, KSFD			736.8	521.8	455.1	420.1	401.4	397.0
95% CONF.DATE-31JULY INFLOW, KSFD	1/		4164.0	4035.5	3989.5	4093.9	3881.1	2990.7
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		4164.0					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1584.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		949.2					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2416.8					
JAN31 ORC, FT	7/		2416.8					
BASE ECC, FT	8/	2439.5						
LOWER LIMIT, FT		2407.0						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		4076.5	3950.8				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1500.0	1519.3				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		952.7	1097.7				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2416.8	2420.1				
FEB28 ORC, FT	7/		2416.8	2419.7				
BASE ECC, FT	8/	2419.7						
LOWER LIMIT, FT		2394.7						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		3976.6	3853.9	3889.8			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1407.0	1426.3	1407.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		959.6	1101.6	1046.4			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2417.0	2420.2	2419.0			
MAR31 ORC, FT	7/		2417.0	2419.9	2419.0			
BASE ECC, FT	8/	2419.9						
LOWER LIMIT, FT		2394.1						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90.7	90.7	92.5	94.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		3768.4	3652.2	3686.3	3881.0		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1317.0	1336.3	1317.0	1317.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1077.8	1213.4	1159.9	965.2		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2419.7	2422.7	2421.5	2417.1		
APR30 ORC, FT	7/		2419.5	2419.5	2419.5	2417.1		
BASE ECC, FT	8/	2419.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		2981.4	2889.4	2916.3	3074.5	3073.8	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0	3000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		1224.0	1243.3	1224.0	1224.0	1224.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		1771.8	1883.1	1836.9	1678.7	1679.4	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2434.9	2437.2	2436.2	2432.9	2432.9	
MAY31 ORC, FT	7/		2431.2	2431.2	2431.2	2431.2	2431.2	
BASE ECC, FT	8/	2431.2						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1507.4	1460.9	1476.1	1555.7	1556.3	1513.3
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		16000.0	16000.0	16534.0	16000.0	16000.0	16000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		744.0	747.3	744.0	744.0	744.0	744.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2765.8	2815.6	2797.1	2717.5	2716.9	2759.9
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2455.3	2456.3	2455.9	2454.3	2454.3	2455.2
JUN30 ORC, FT	7/		2454.4	2454.4	2454.4	2454.3	2454.3	2454.4
BASE ECC, FT	8/	2454.4						
JUL 31 ORC, FT			2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (3529.2 KSFD) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 3M (metric): 2017 Keenleyside Variable Refill Curve

		INITIAL	JAN 1 Total	FEB 1 Total	MAR 1 Total	APR 1 Total	MAY 1 Total	JUN 1 Total
PROBABLE DATE-31JULY INFLOW, km3			25.1	22.9	22.6	23.1	21.9	15.9
& IN hm3	**		25145.9	22864.7	22645.0	23139.5	21920.6	15945.5
95% FORECAST ERROR FOR DATE, IN hm3			3626.0	2680.3	2333.4	1982.3	1767.6	1660.2
95% CONF.DATE-31JULY INFLOW, hm3	1/		19421.0	21993.7	21259.2	21505.0	20753.4	15788.9
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		21518.7					
MIN FEB1-JUL31 OUTFLOW, hm3	3/		7310.4					
UPSTREAM DISCHARGE, hm3	4/		6312.2					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		861.8					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		422.5					
JAN31 ORC, m	7/		422.5					
BASE ECC, m	8/	425.5						
LOWER LIMIT, m		421.0						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		21002.2	19700.8				
MIN MAR1-JUL31 OUTFLOW, hm3	3/		6967.9	6967.9				
UPSTREAM DISCHARGE, hm3	4/		6303.8	5992.5				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		1027.3	2017.4				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		423.0	425.6				
FEB28 ORC, m	7/		423.0	424.6				
BASE ECC, m	8/	424.6						
LOWER LIMIT, m		420.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		20356.6	19095.2	19701.1			
MIN APR1-JUL31 OUTFLOW, hm3	3/		6588.7	6588.7	6588.7			
UPSTREAM DISCHARGE, hm3	4/		6286.8	5976.3	6074.4			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		1276.7	2227.6	1719.8			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		423.6	426.1	424.8			
MAR31 ORC, m	7/		422.5	422.5	422.5			
BASE ECC, m	8/	422.5						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.9	87.9	90.1	92.8		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		18871.9	17702.5	18238.7	19592.6		
MIN MAY1-JUL31 OUTFLOW, hm3	3/		6221.7	6221.7	6221.7	6221.7		
UPSTREAM DISCHARGE, hm3	4/		6016.9	6016.9	6016.9	6273.0		
VRC APR30 RESERVOIR CONTENT, hm3	5/		2124.6	3294.0	2757.8	1659.9		
VRC APR30 RESERVOIR CONTENT, METERS	6/		425.8	428.7	427.4	424.6		
APR30 ORC, Fm	7/		424.8	424.8	424.8	424.7		
BASE ECC, m	8/	424.8						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		13987.1	13120.4	13526.7	14535.8	14952.3	
MIN JUN1-JUL31 OUTFLOW, hm3	3/		5842.5	5842.5	5842.5	5842.5	5842.5	
UPSTREAM DISCHARGE, hm3	4/		4720.2	4720.2	4720.2	4720.2	4720.2	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		5333.4	6200.1	5793.8	4784.8	4368.3	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		433.2	435.1	434.2	432.1	431.1	
MAY31 ORC, m	7/		432.5	432.5	432.5	432.1	431.1	
BASE ECC, m	8/	432.5						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		6520.2	6116.1	6316.5	6791.8	6992.5	6670.3
MIN JUL1-JUL31 OUTFLOW, hm3	3/		3640.5	3640.5	3640.5	3640.5	3640.5	3640.5
UPSTREAM DISCHARGE, hm3	4/		1976.1	1976.1	1976.1	1985.8	1987.4	1976.1
VRC JUN30 RESERVOIR CONTENT, hm3	5/		7854.4	8258.4	8058.0	7592.4	7393.3	7704.3
VRC JUN30 RESERVOIR CONTENT, METERS	6/		438.4	439.2	438.8	437.9	437.5	438.1
JUN30 ORC, m	7/		438.4	439.2	438.8	437.9	437.5	438.1
BASE ECC, m	8/	440.1						
JUL 31 ECC, m			440.1	440.1	440.1	440.1	440.1	440.1

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ CUMMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS
4/ UPSTREAM DISCHARGE REQUIREMENT.
5/ MAXIMUM(FULL CONTENT (8757.85 hm3) MINUS 2/ PLUS 3/ MINUS /4 OR LOWER LIMIT)
6/ ELEV. FROM 5/, INTERP. FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 3: 2017 Keenleyside Variable Refill Curve

		INITIAL	JAN 1 Total	FEB 1 Total	MAR 1 Total	APR 1 Total	MAY 1 Total	JUN 1 Total
PROBABLE DATE-31JULY INFLOW, KAF			20385.9	18536.5	18358.4	18759.3	17771.1	12927.1
& IN KSFD	**		10277.9	9345.5	9255.7	9457.8	8959.6	6517.4
95% FORECAST ERROR FOR DATE, IN KSFD			1482.1	1095.5	953.7	810.2	722.5	678.6
95% CONF.DATE-31JULY INFLOW, KSFD	1/		7937.9	8989.5	8689.3	8789.8	8482.5	6453.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		8795.3					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		2988.0					
UPSTREAM DISCHARGE, KSFD	4/		2580.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		352.3					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1386.2					
JAN31 ORC, FT	7/		1386.2					
BASE ECC, FT	8/	1395.9						
LOWER LIMIT, FT		1381.1						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		8584.2	8052.3				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		2848.0	2848.0				
UPSTREAM DISCHARGE, KSFD	4/		2576.5	2449.3				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		419.9	824.6				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1387.7	1396.2				
FEB28 ORC, FT	7/		1387.7	1393.0				
BASE ECC, FT	8/	1393.0						
LOWER LIMIT, FT		1379.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		8320.4	7804.8	8052.4			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		2693.0	2693.0	2693.0			
UPSTREAM DISCHARGE, KSFD	4/		2569.6	2442.7	2482.8			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		521.8	910.5	702.9			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1389.9	1398.0	1393.7			
MAR31 ORC, FT	7/		1386.3	1386.3	1386.3			
BASE ECC, FT	8/	1386.3						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.9	87.9	90.1	92.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		7713.5	7235.5	7454.7	8008.1		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		2543.0	2543.0	2543.0	2543.0		
UPSTREAM DISCHARGE, KSFD	4/		2459.3	2459.3	2459.3	2564.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		868.4	1346.4	1127.2	678.5		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1397.1	1406.4	1402.2	1393.2		
APR30 ORC, FT	7/		1393.8	1393.8	1393.8	1393.2		
BASE ECC, FT	8/	1393.8						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		5717.0	5362.7	5528.8	5941.2	6111.5	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		2388.0	2388.0	2388.0	2388.0	2388.0	
UPSTREAM DISCHARGE, KSFD	4/		1929.3	1929.3	1929.3	1929.3	1929.3	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2179.9	2534.2	2368.1	1955.7	1785.4	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1421.4	1427.4	1424.6	1417.5	1414.5	
MAY31 ORC, FT	7/		1419.0	1419.0	1419.0	1417.5	1414.5	
BASE ECC, FT	8/	1419.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		2665.0	2499.8	2581.8	2776.0	2858.1	2726.3
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		1488.0	1488.0	1488.0	1488.0	1488.0	1488.0
UPSTREAM DISCHARGE, KSFD	4/		807.7	807.7	807.7	811.7	812.3	807.7
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3210.3	3375.5	3293.5	3103.2	3021.9	3149.0
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1438.3	1440.9	1439.6	1436.6	1435.3	1437.3
JUN30 ORC, FT	7/		1438.3	1440.9	1439.6	1436.6	1435.3	1437.3
BASE ECC, FT	8/	1444.0						
JUL 31 ECC, FT			1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ CUMMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS
4/ UPSTREAM DISCHARGE REQUIREMENT.
5/ MAXIMUM(FULL CONTENT (3579.6 KSFD) MINUS 2/ PLUS 3/ MINUS /4 OR LOWER LIMIT)
6/ ELEV. FROM 5/, INTERP. FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF THE ARC OR CRC1 IN DOP

Table 4M (metric): 2017 Duncan Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			2.2	2.1	2.0	2.0	2.0	1.5
& IN hm3	**		2158.4	2099.7	2041.7	2041.7	1983.0	1461.6
95% FORECAST ERROR FOR DATE, IN hm3			308.9	255.2	256.9	229.6	212.7	190.8
95% CONF.DATE-31JULY INFLOW, hm3	1/		1849.5	1844.4	1784.8	1812.1	1770.3	1270.8
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		1849.5					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		307.0					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		184.4					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		551.5					
JAN31 ORC, m	7/		553.5					
BASE ECC, m	8/	560.0						
LOWER LIMIT, m		553.5						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.1	98.1				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		1812.5	1807.6				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		300.2	302.6				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		214.5	221.9				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		552.2	552.3				
FEB28 ORC, m	7/		552.2	552.3				
BASE ECC, m	8/	553.4						
LOWER LIMIT, m		549.6						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.7	95.7	97.6			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		1768.1	1763.3	1742.0			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8			
MIN APR1-JUL31 OUTFLOW, hm3	4/		292.6	295.0	292.6			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		251.3	258.6	277.4			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		552.9	553.1	553.5			
MAR31 ORC, m	7/		551.0	552.3	552.6			
BASE ECC, m	8/	553.9						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.7	89.7	91.6	93.8		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		1657.1	1652.6	1633.1	1697.9		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8	2.8		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		285.3	287.7	285.3	285.3		
VRC APR30 RESERVOIR CONTENT, hm3	5/		355.0	361.9	379.0	314.2		
VRC APR30 RESERVOIR CONTENT, METERS	6/		555.0	555.1	555.4	554.2		
APR30 ORC, m	7/		551.0	552.3	552.6	551.0		
BASE ECC, m	8/	554.6						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.5	67.5	69.0	70.6	75.3	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		1244.7	1241.3	1226.2	1273.9	1329.5	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8	2.8	2.8	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		277.7	280.1	277.7	277.7	277.7	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		759.8	765.6	778.3	730.6	675.0	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		562.1	562.2	562.4	561.7	560.7	
MAY31 ORC, m	7/		559.9	559.9	559.9	559.9	559.9	
BASE ECC, m	8/	559.9						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			32.5	32.5	33.3	34.0	36.3	48.2
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		599.2	597.6	590.8	612.5	640.8	611.3
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		34.0	34.0	34.0	34.0	34.0	34.0
MIN JUL1-JUL31 OUTFLOW, hm3	4/		189.6	192.0	189.6	189.6	189.6	189.6
VRC JUN30 RESERVOIR CONTENT, hm3	5/		1317.2	1321.3	1325.6	1303.9	1275.6	1305.2
VRC JUN30 RESERVOIR CONTENT, METERS	6/		570.8	570.9	570.9	570.6	570.2	570.6
JUN30 ORC, m	7/		570.5	570.5	570.5	570.5	570.2	570.5
BASE ECC, m	8/	570.5						
JUL 31 ECC, m			576.7	576.7	576.7	576.7	576.7	576.7

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (1726.81 hm3) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER THAN THE ARC OR CRC1 IN DOP

Table 4: 2017 Duncan Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			1749.8	1702.2	1655.2	1655.2	1607.6	1184.9
& IN KSFD	**		882.2	858.2	834.5	834.5	810.5	597.4
95% FORECAST ERROR FOR DATE, IN KSFD			126.3	104.3	105.0	93.9	86.9	78.0
95% CONF.DATE-31JULY INFLOW, KSFD	1/		755.9	753.9	729.5	740.6	723.6	519.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		755.9					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		125.5					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		75.4					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1809.5					
JAN31 ORC, FT	7/		1815.8					
BASE ECC, FT	8/	1837.2						
LOWER LIMIT, FT		1815.8						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.1	98.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		740.8	738.8				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		122.7	123.7				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		87.7	90.7				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1811.6	1812.1				
FEB28 ORC, FT	7/		1811.6	1812.1				
BASE ECC, FT	8/	1815.6						
LOWER LIMIT, FT		1803.3						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.7	95.7	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		722.7	720.7	712.0			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		119.6	120.6	119.6			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		102.7	105.7	113.4			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1814.1	1814.6	1815.8			
MAR31 ORC, FT	7/		1807.8	1811.8	1812.9			
BASE ECC, FT	8/	1817.1						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.7	89.7	91.6	93.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		677.3	675.5	667.5	694.0		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0	100.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		116.6	117.6	116.6	116.6		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		145.1	147.9	154.9	128.4		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1820.9	1821.3	1822.3	1818.2		
APR30 ORC, FT	7/		1807.8	1811.8	1812.9	1807.8		
BASE ECC, FT	8/	1819.7						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.5	67.5	69.0	70.6	75.3	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		508.7	507.4	501.2	520.7	543.4	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0	100.0	100.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		113.5	114.5	113.5	113.5	113.5	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		310.6	312.9	318.1	298.6	275.9	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1844.3	1844.6	1845.3	1842.7	1839.6	
MAY31 ORC, FT	7/		1836.8	1836.8	1836.8	1836.8	1836.8	
BASE ECC, FT	8/	1836.8						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			32.5	32.5	33.3	34.0	36.3	48.2
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		244.9	244.3	241.5	250.3	261.9	249.8
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		1200.0	1200.0	1200.0	1200.0	1200.0	1200.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		77.5	78.5	77.5	77.5	77.5	77.5
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		538.4	540.0	541.8	533.0	521.4	533.5
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1872.7	1872.9	1873.1	1872.1	1870.7	1872.1
JUN30 ORC, FT	7/		1871.7	1871.7	1871.7	1871.7	1870.7	1871.7
BASE ECC, FT	8/	1871.7						
JUL 31 ECC, FT			1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (705.8 KSFD) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 5M (metric): 2017 Libby Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE JAN-31JULY INFLOW, km3			8.5	7.1	8.5	9.7	10.3	10.3
PROBABLE JAN-31JULY INFLOW, hm3			8512.5	7095.1	8478.9	9700.0	10302.1	9633.5
95% FORECAST ERROR FOR DATE, hm3			2246.2	1813.2	1721.9	1250.7	1217.4	1186.6
OBSERVED JAN1-DATE INFLOW, IN hm3			0.0	308.3	558.6	1095.1	2008.2	4867.3
95% CONF.DATE-31JULY INFLOW, hm3	1/		6266.0	4973.4	6198.2	7354.0	7076.5	3579.6
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		6071.7					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		2671.7					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		2742.1					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		727.8					
JAN31 ORC, m	7/		727.8					
BASE ECC, m	9/	736.4						
LOWER LIMIT, m		720.5						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		5896.3	4829.1				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		2397.7	2397.7				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		2643.6	3710.5				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		727.0	735.1				
FEB28 ORC, m	7/		727.0	735.1				
BASE ECC, m	9/	735.5						
LOWER LIMIT, m		709.3						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.6	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		5677.1	4650.3	5969.0			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3			
MIN APR1-JUL31 OUTFLOW, hm3	4/		2094.3	2094.3	2094.3			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		2559.4	3586.2	2267.5			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		726.2	734.3	723.7			
MAR31 ORC, m	7/		726.2	734.3	723.7			
BASE ECC, m	9/	734.7						
LOWER LIMIT, m		700.1						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.4	85.0	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		5163.3	4227.5	5423.6	6684.8		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3	113.3		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		1800.7	1800.7	1800.7	1800.7		
VRC APR30 RESERVOIR CONTENT, hm3	5/		2779.6	3715.4	2519.3	1258.0		
VRC APR30 RESERVOIR CONTENT, METERS	6/		728.1	735.1	725.9	713.6		
APR30 ORC, m	7/		728.1	734.4	725.9	713.6		
BASE ECC, m	9/	734.4						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.3	57.0	58.7	61.0	67.1	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		3465.1	2834.9	3638.3	4486.1	4748.4	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		226.5	226.5	226.5	226.5	226.5	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		1497.3	1497.3	1497.3	1497.3	1497.3	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		4174.4	4804.6	4001.2	3153.4	2891.1	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		738.1	742.0	737.0	731.1	729.1	
MAY31 ORC, m	7/		738.1	741.5	737.0	731.1	729.1	
BASE ECC, m	9/	741.5						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.8	20.3	20.9	21.8	23.9	35.6
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		1240.7	1009.7	1295.5	1603.3	1691.3	1274.4
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		339.8	339.8	339.8	339.8	339.8	339.8
MIN JUL1-JUL31 OUTFLOW, hm3	4/		910.1	910.1	910.1	910.1	910.1	910.1
VRC JUN30 RESERVOIR CONTENT, hm3	5/		5811.7	6042.6	5756.8	5449.1	5361.0	5777.9
VRC JUN30 RESERVOIR CONTENT, METERS	6/		747.7	749.0	747.4	745.7	745.2	747.5
JUN30 ORC, m	7/		747.7	749.0	747.4	745.7	745.2	747.5
BASE ECC, m	9/	749.5						
JUL 31 ORC, m			749.5	749.5	749.5	749.5	749.5	749.5
JAN1-JUL31 FORECAST,-EARLYBIRD, km3	8/		119.2	115.2	134.2	161.3	169.0	175.0

1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW) MINUS OBSERVED INFLOW.
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (2510.5 KSFD) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143
7/ LOWER OF ELEV. FROM 6/ OR BASE VRC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT
8/ MEASURED AT THE DALLES USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3/.
9/ HIGHER OF ARC OR CRC1 IN DOP

Table 5: 2017 Libby Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE JAN-31JULY INFLOW, KAF			6901.0	5752.0	6873.9	7863.8	8352.0	7809.9
PROBABLE JAN-31JULY INFLOW, KSFD			3479.3	2900.0	3465.6	3964.7	4210.8	3937.5
95% FORECAST ERROR FOR DATE, KSFD			918.1	741.1	703.8	511.2	497.6	485.0
OBSERVED JAN1-DATE INFLOW, IN KSFD			0.0	126.0	228.3	447.6	820.8	1989.4
95% CONF.DATE-31JULY INFLOW, KSFD	1/		2561.1	2032.8	2533.4	3005.8	2892.4	1463.1
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		2481.7					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1092.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1120.8					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2387.8					
JAN31 ORC, FT	7/		2387.8					
BASE ECC, FT	9/	2415.9						
LOWER LIMIT, FT		2363.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		2410.0	1973.8				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		980.0	980.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1080.5	1516.6				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2385.1	2411.8				
FEB28 ORC, FT	7/		2385.1	2411.8				
BASE ECC, FT	9/	2413.1						
LOWER LIMIT, FT		2327.1						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.6	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		2320.4	1900.7	2439.7			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0	4000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		856.0	856.0	856.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1046.1	1465.8	926.8			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2382.7	2409.0	2374.2			
MAR31 ORC, FT	7/		2382.7	2409.0	2374.2			
BASE ECC, FT	9/	2410.3						
LOWER LIMIT, FT		2297.0						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.4	85.0	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		2110.4	1727.9	2216.8	2732.3		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0	4000.0	4000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		736.0	736.0	736.0	736.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1136.1	1518.6	1029.7	514.2		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2388.9	2411.9	2381.6	2341.3		
APR30 ORC, FT	7/		2388.9	2409.3	2381.6	2341.3		
BASE ECC, FT	9/	2409.3						
		2287.0						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.3	57.0	58.7	61.0	67.1	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		1416.3	1158.7	1487.1	1833.6	1940.8	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		8000.0	8000.0	8000.0	8000.0	8000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		612.0	612.0	612.0	612.0	612.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		1706.2	1963.8	1635.4	1288.9	1181.7	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2421.7	2434.4	2418.1	2398.7	2391.9	
MAY31 ORC, FT	7/		2421.7	2432.7	2418.1	2398.7	2391.9	
BASE ECC, FT	9/	2432.7						
		2287.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.8	20.3	20.9	21.8	23.9	35.6
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		507.1	412.7	529.5	655.3	691.3	520.9
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		12000.0	12000.0	12000.0	12000.0	12000.0	12000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		372.0	372.0	372.0	372.0	372.0	372.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2375.4	2469.8	2353.0	2227.2	2191.2	2361.6
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2453.1	2457.2	2452.2	2446.6	2444.9	2452.5
JUN30 ORC, FT	7/		2453.1	2457.2	2452.2	2446.6	2444.9	2452.5
BASE ECC, FT	9/	2459.0						
		2287.0						
JUL 31 ORC, FT			2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		96.6	93.4	108.8	130.8	137.0	141.9

1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW) MINUS OBSERVED INFLOW.
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (2510.5 KSFD) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143
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8/ MEASURED AT THE DALLES USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3/.
9/ HIGHER OF ARC OR CRC1 IN DOP

Table 6: Computation of Initial Controlled Flow

Columbia River at The Dalles, OR

Metric and English Units, based on April 2017 forecast

Upstream Storage Corrections	**Metric (km^3)**	**English (Maf)**
Mica	8.514	6.902
Arrow	4.441	3.600
Duncan	1.675	1.358
Libby	4.180	3.389
Hungry Horse	0.790	0.641
Flathead Lake	0.617	0.500
Noxon Rapids	0.000	0.000
Pend Oreille Lake	0.617	0.500
Grand Coulee	5.676	4.602
Brownlee	0.865	0.701
Dworshak	1.370	1.111
John Day	0.195	0.158
Total Upstream Storage Corrections	28.940	23.462

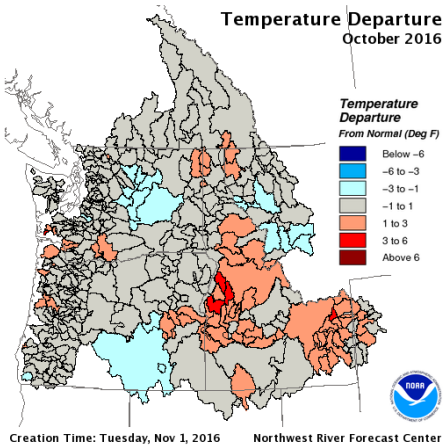
Adjusted TDA May-Aug Runoff Volume	**Metric (km^3)**	**English (Maf)**
TDA May-Aug Runoff Volume (1May Forecast)	102.609	83.187
Less Estimated Depletions	-2.502	-2.028
Less Total Upstream Storage Corrections	-28.940	-23.462
Adjusted TDA May-Aug Runoff Volume	71.168	57.697

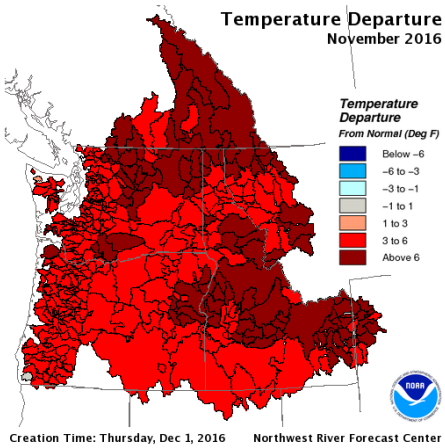
Initial Controlled Flow	**m^3/s**	**kcfs**
Determined using 'Adjusted TDA May-Aug Runoff Volume' and Chart 1 of the Flood Control Operating Plan	**10419.9**	**368.0**

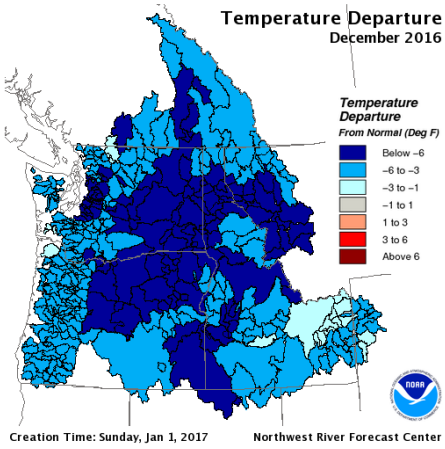
VIII - CHARTS

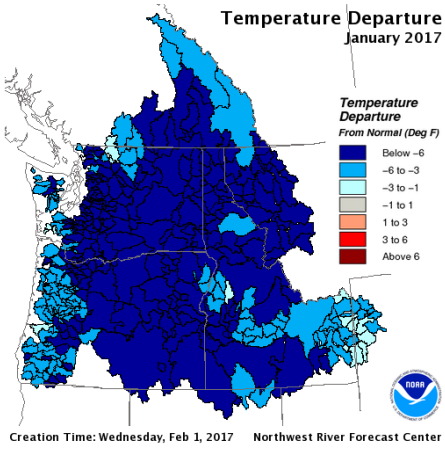
Chart 1: Pacific Northwest Monthly Temperature Departures

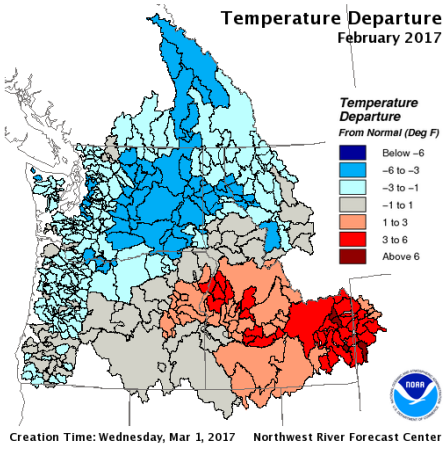
October – March











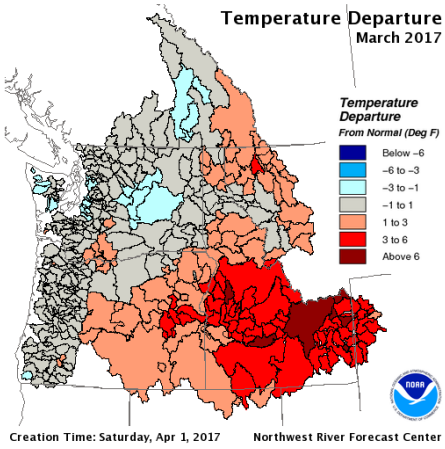
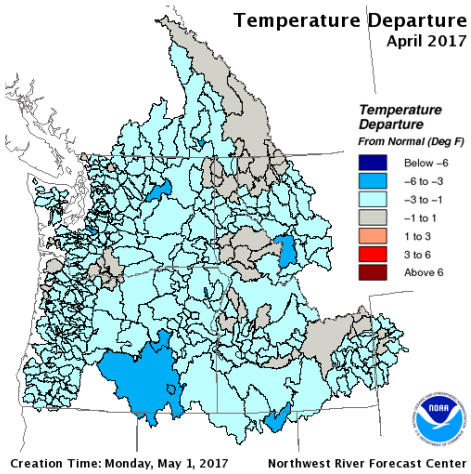
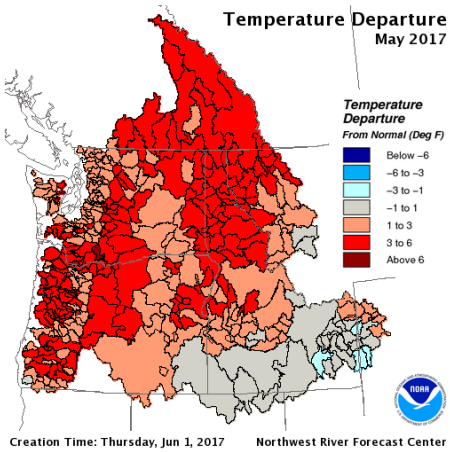
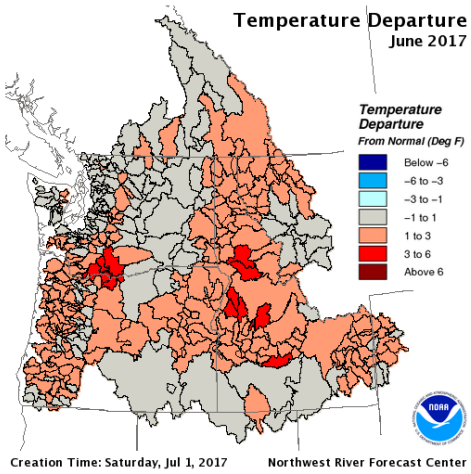


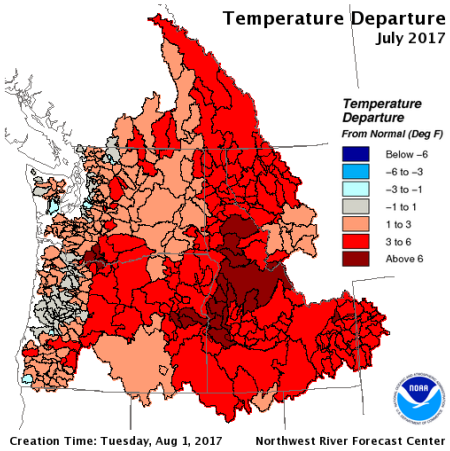
Chart 1: Pacific Northwest Monthly Temperature Departures (Continued)

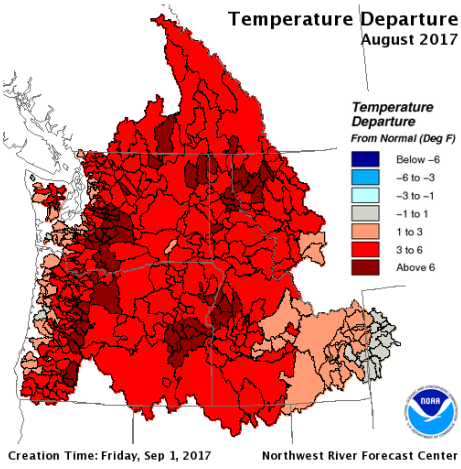
April – September











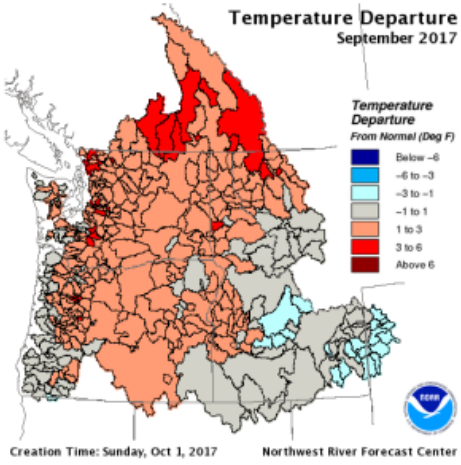
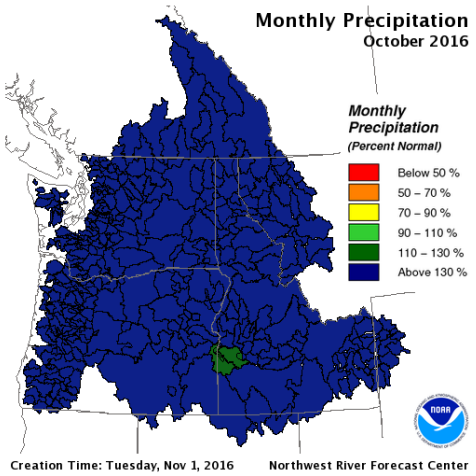
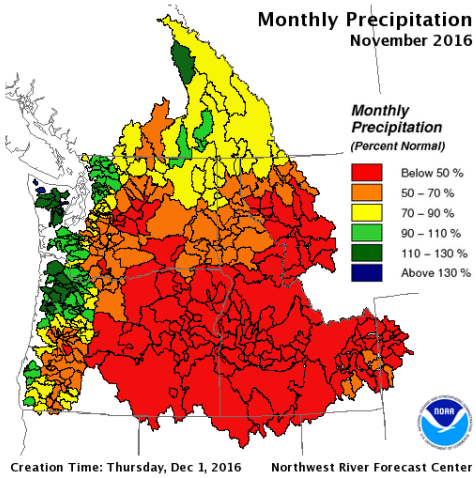
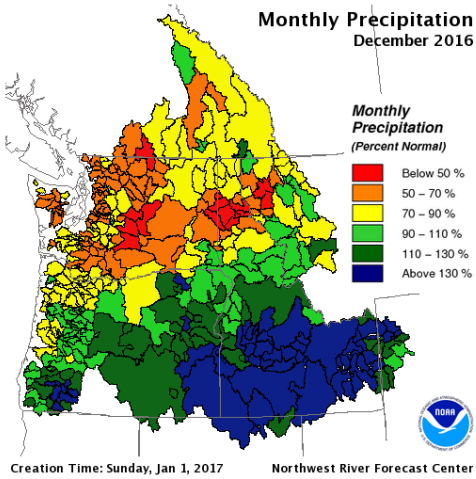


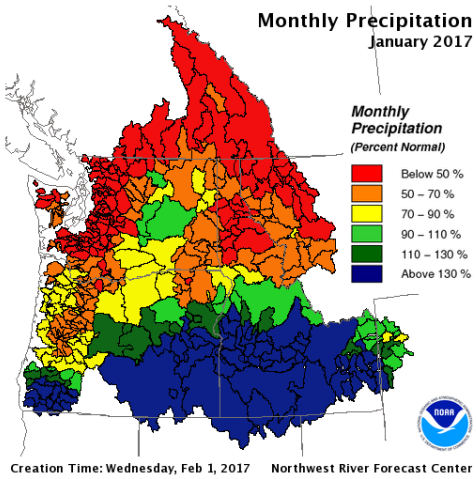
Chart 1 A: Pacific Northwest Monthly Precipitation Departures

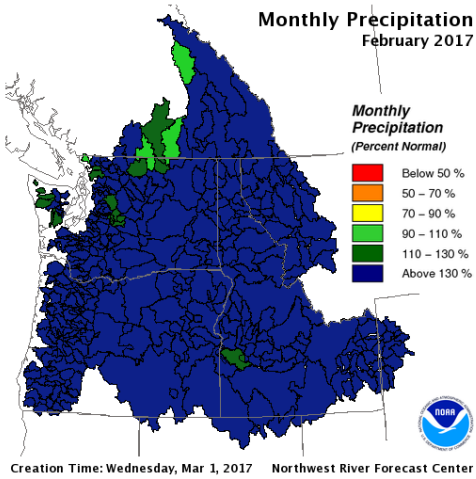
October – March











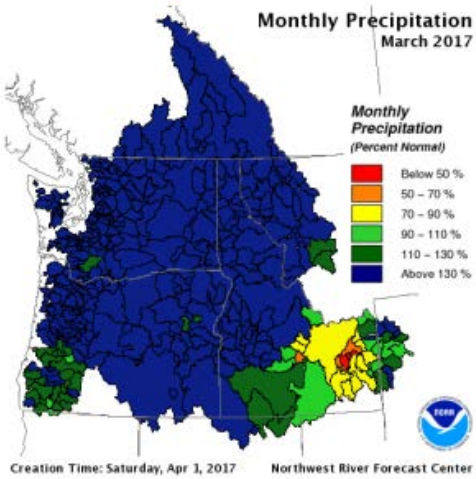
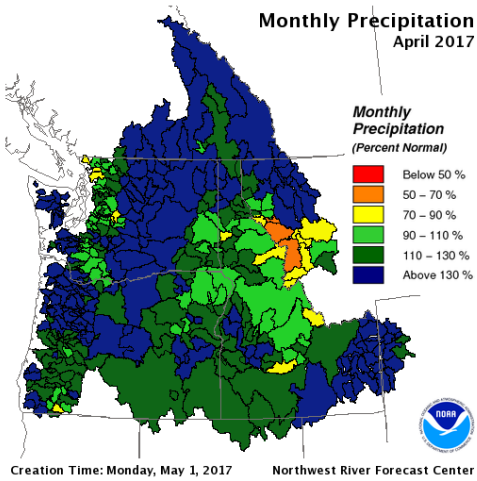
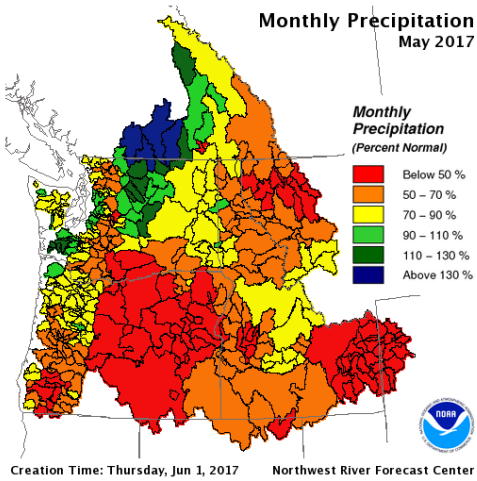
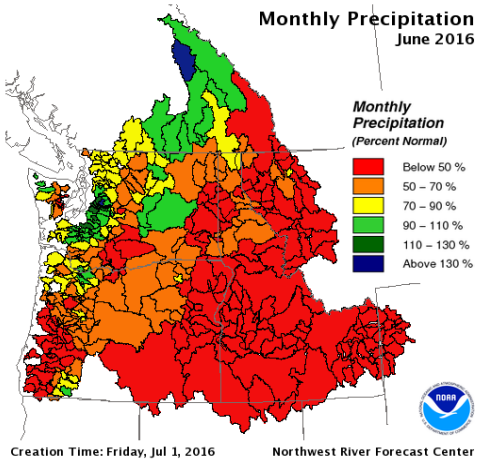


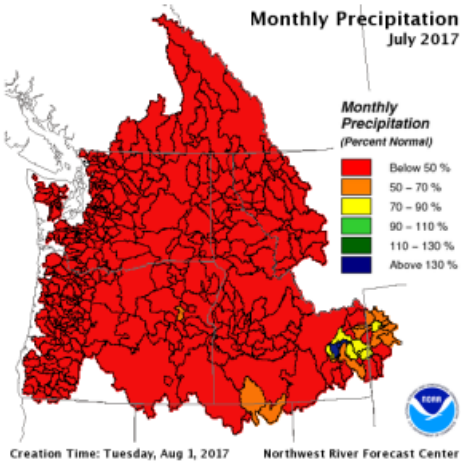
Chart 1 A: Pacific Northwest Monthly Precipitation Departures (Continued)

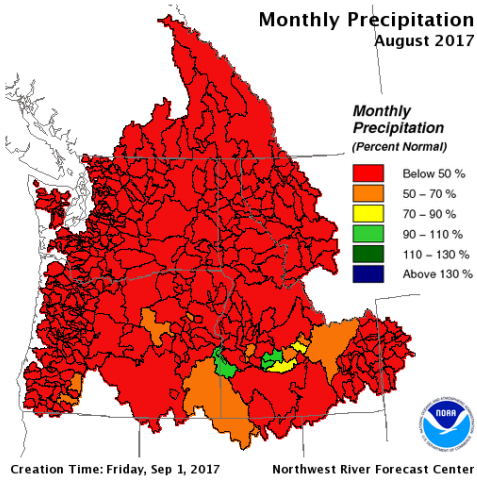
April – September











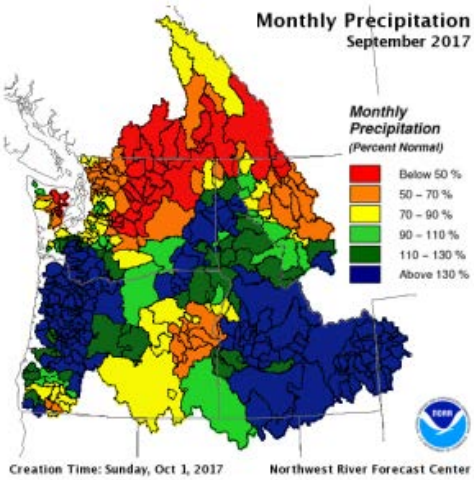


Chart 2: Seasonal Precipitation Columbia River Basin

October 2016 – September 2017

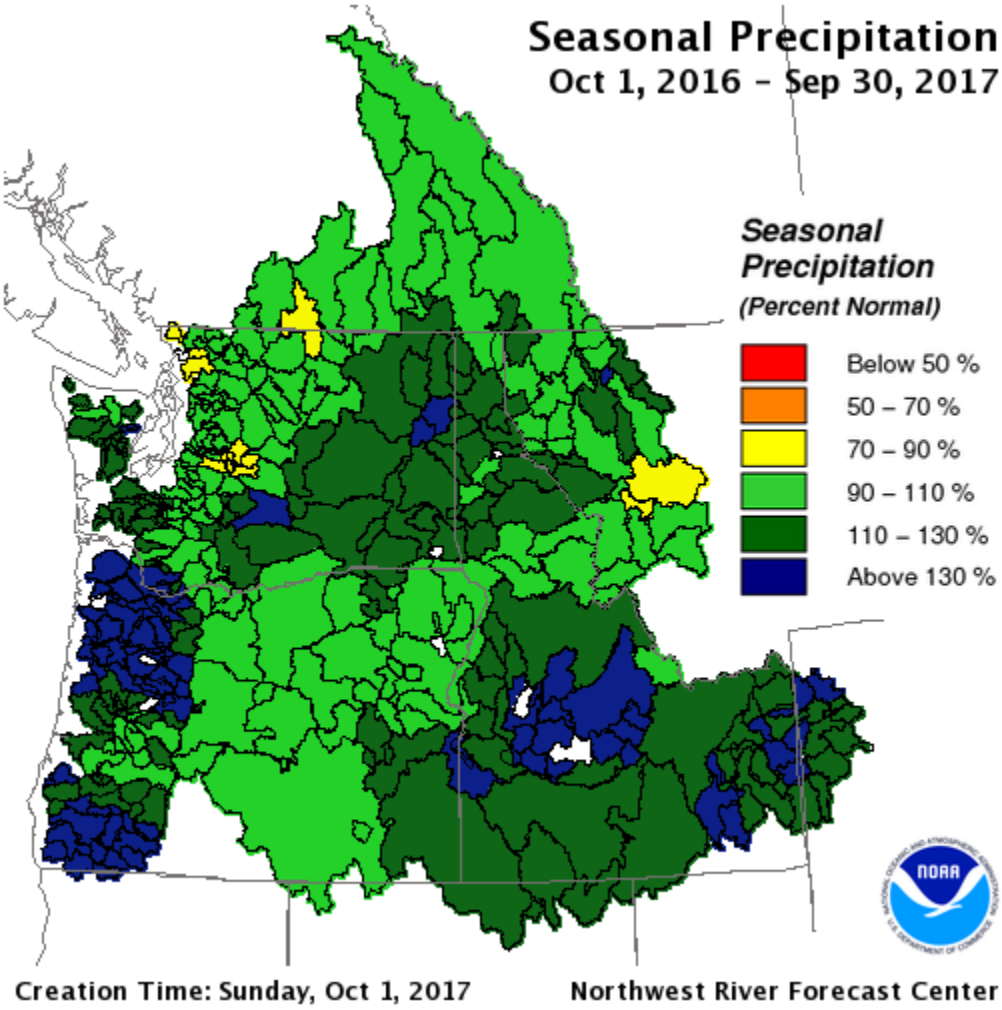


Chart 3: Columbia Basin Snowpack

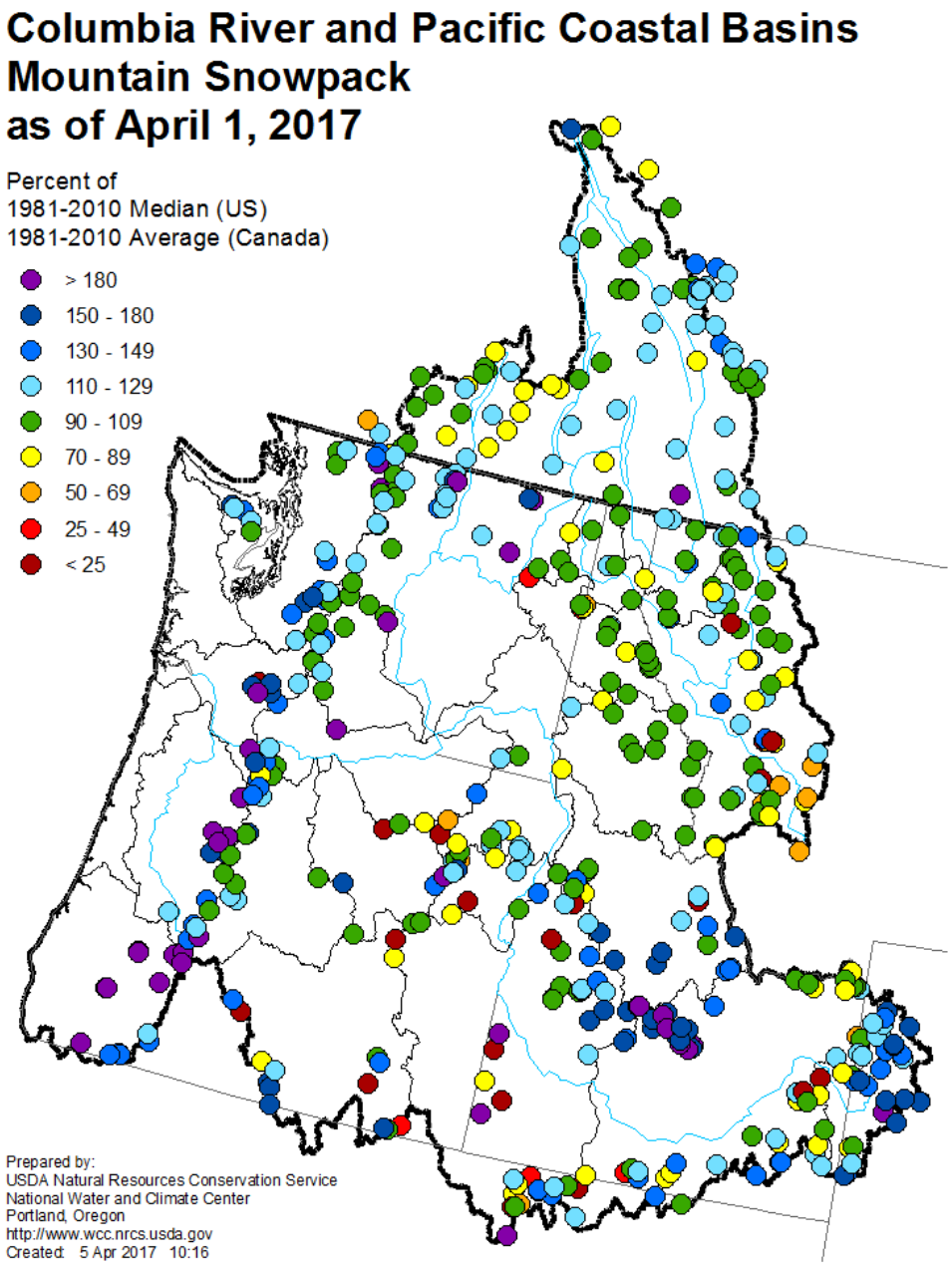


Chart 4: Accumulated Precipitation for WY 2017

At Primary Columbia River Basins

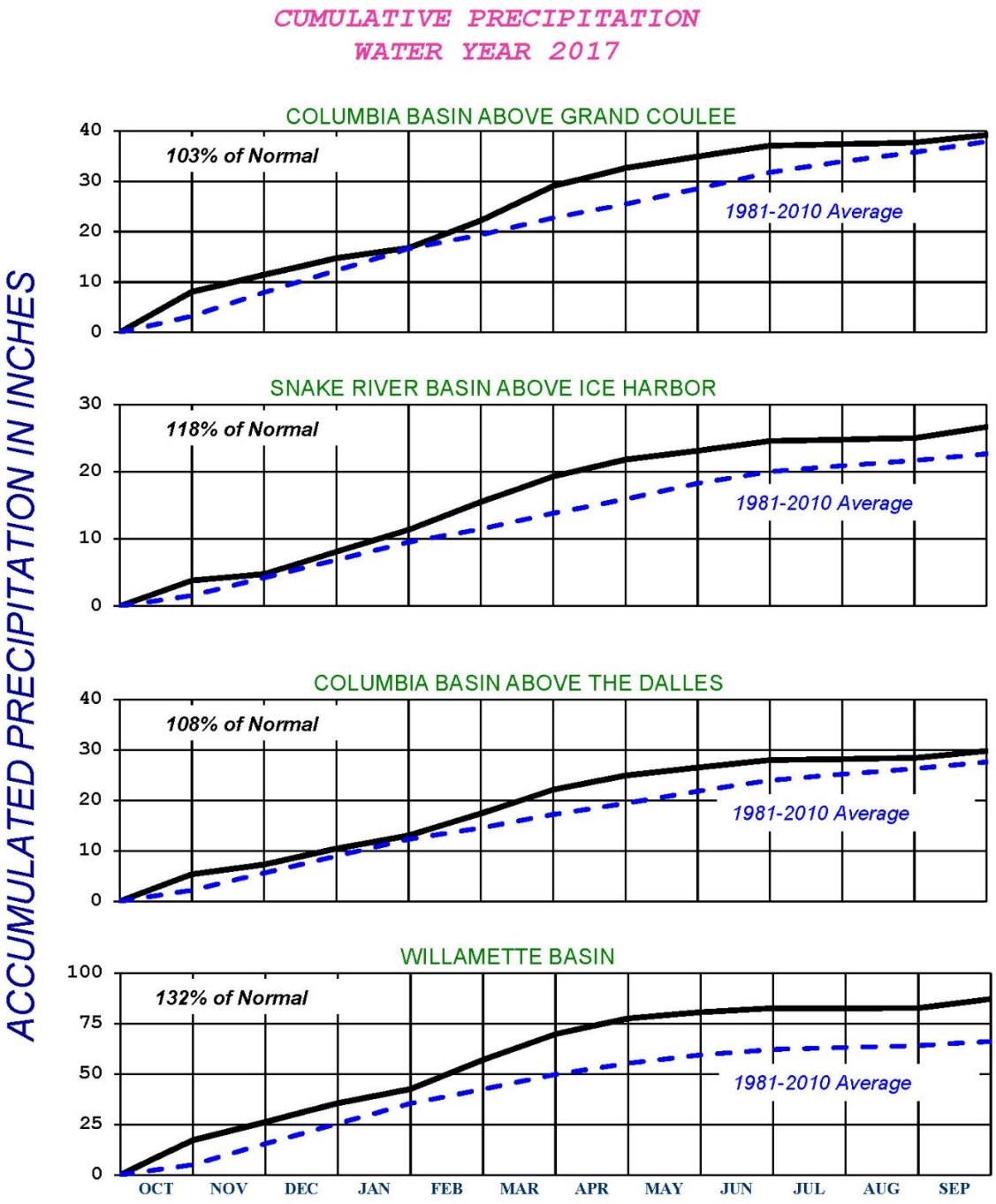


Chart 5: Regulation of Mica

1 August 2016– 30 September 2017

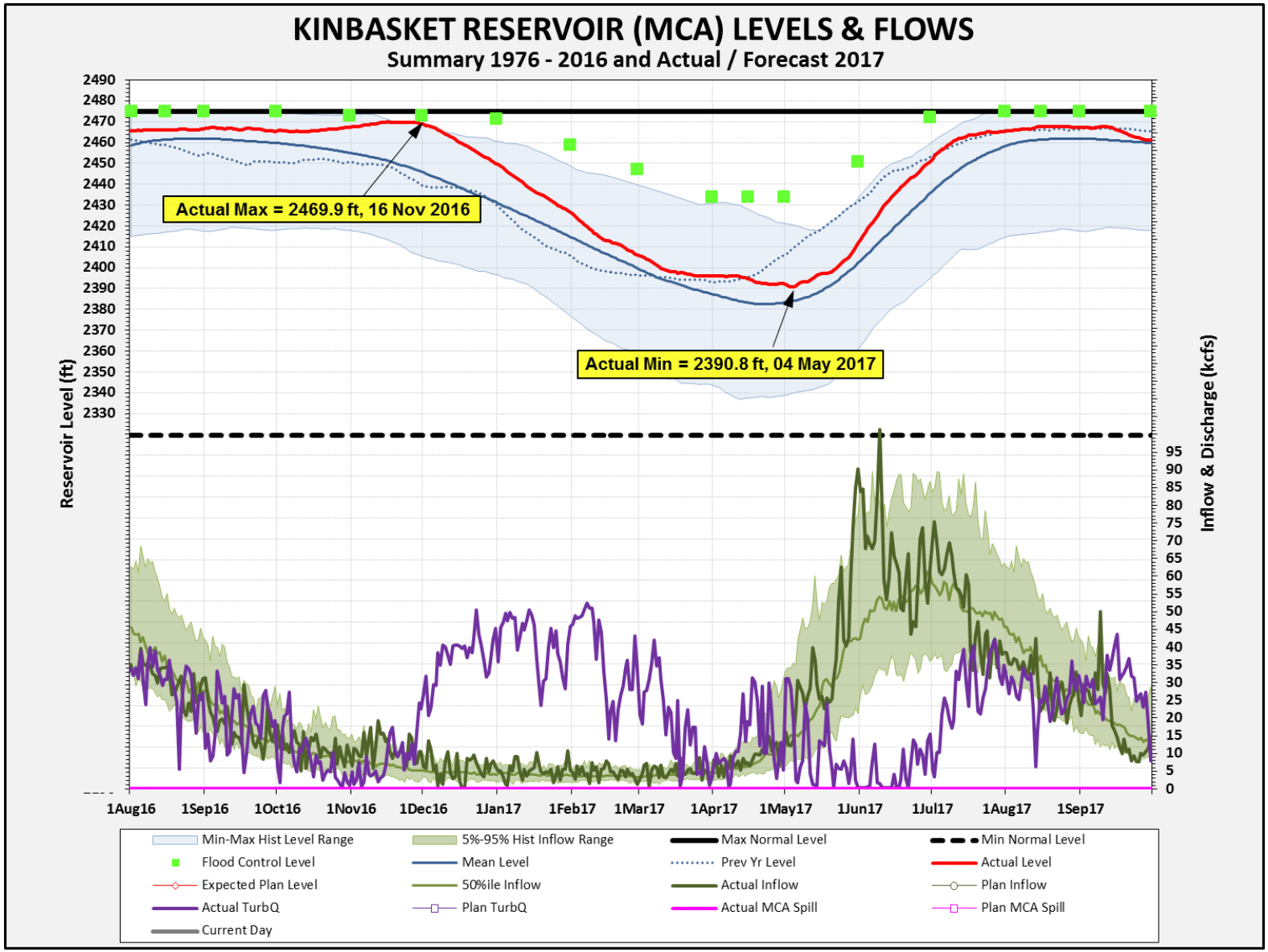


Chart 6: Regulation of Keenleyside

01 August 2016– 30 September 2017

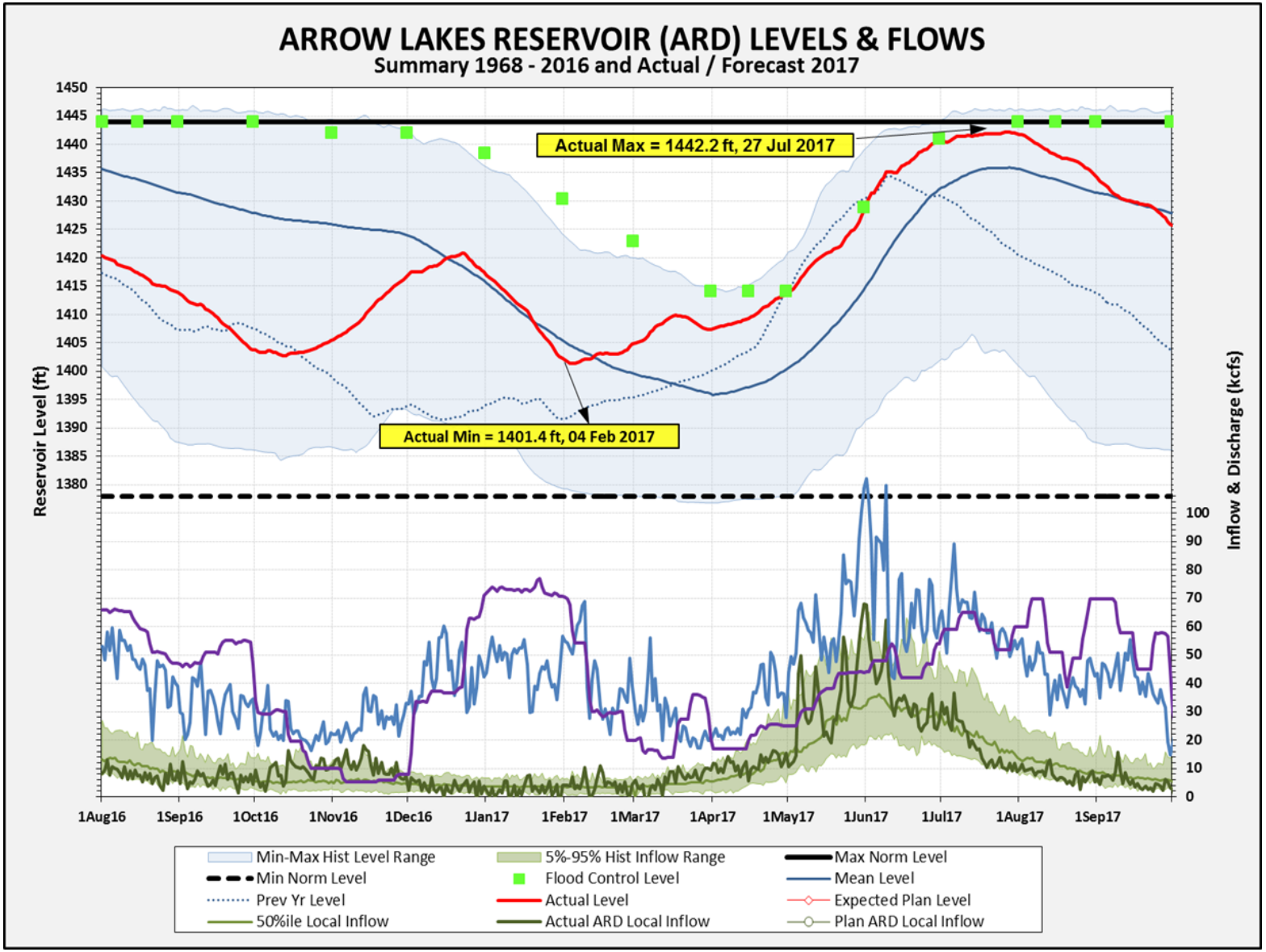


Chart 7: Regulation of Duncan

01 August 2016 – 30 September 2017

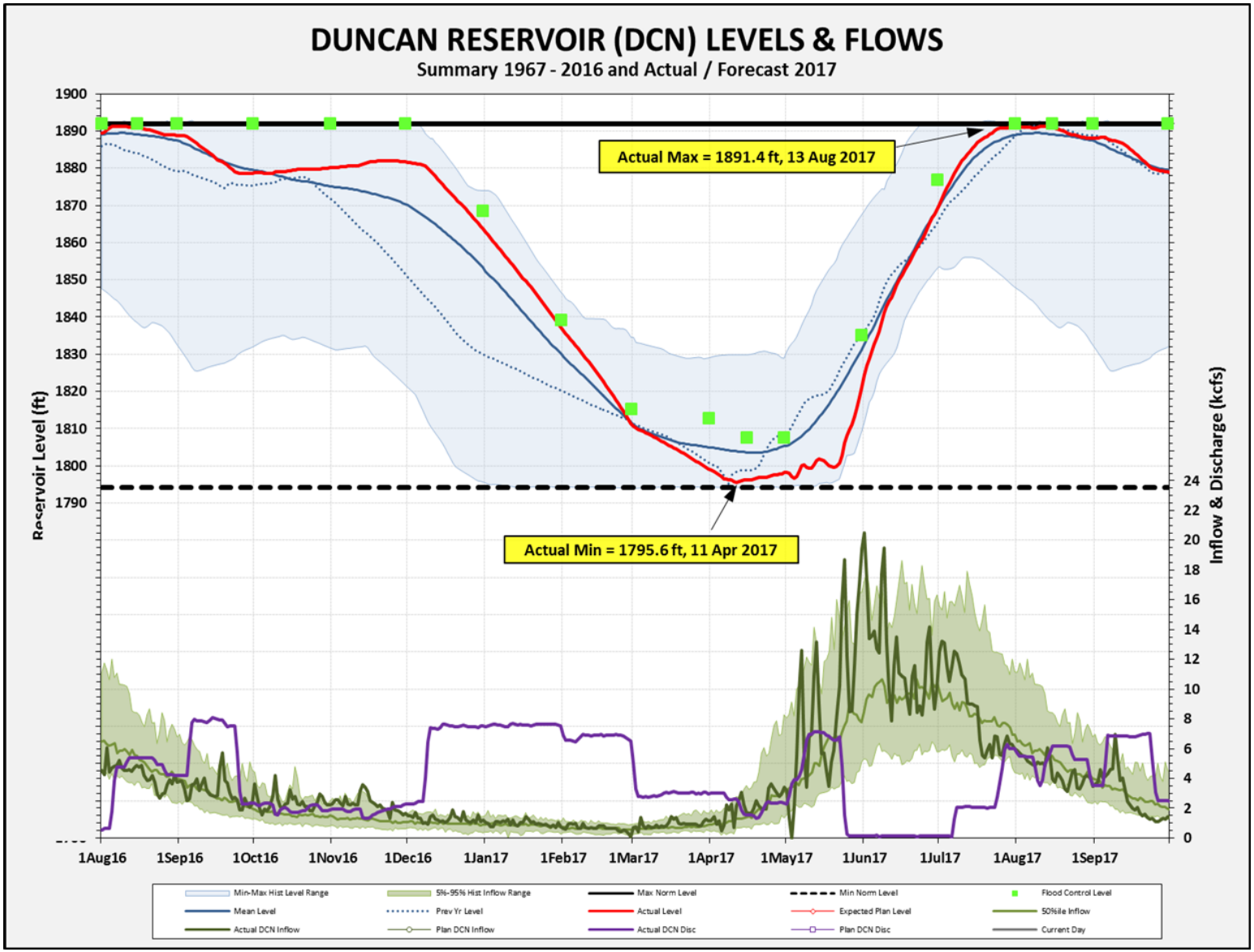


Chart 8: Regulation of Libby

01 August 2016 – 30 September 2017

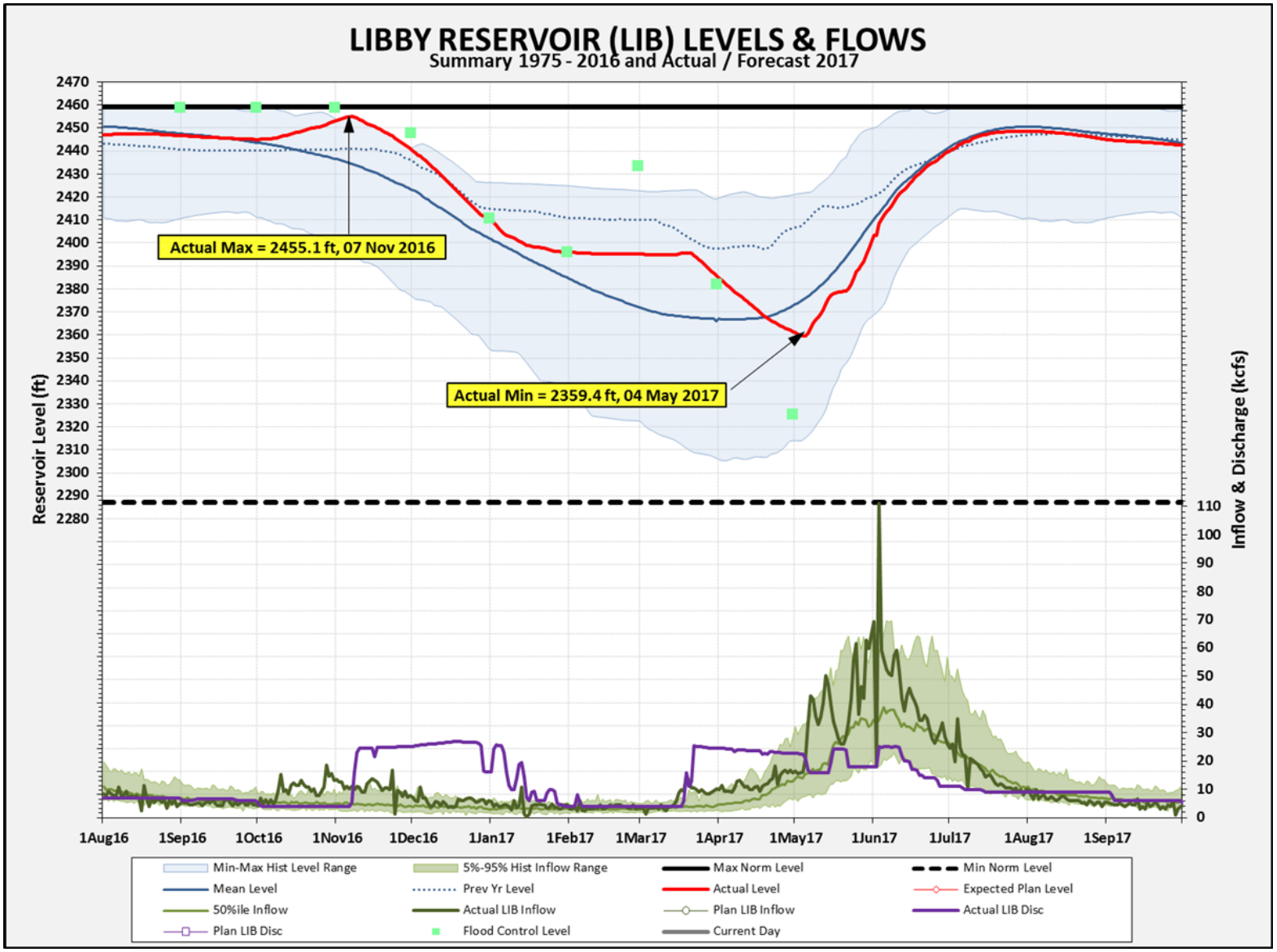


Chart 9: Regulation of Kootenay Lake

01 August 2016 – 30 September 2017

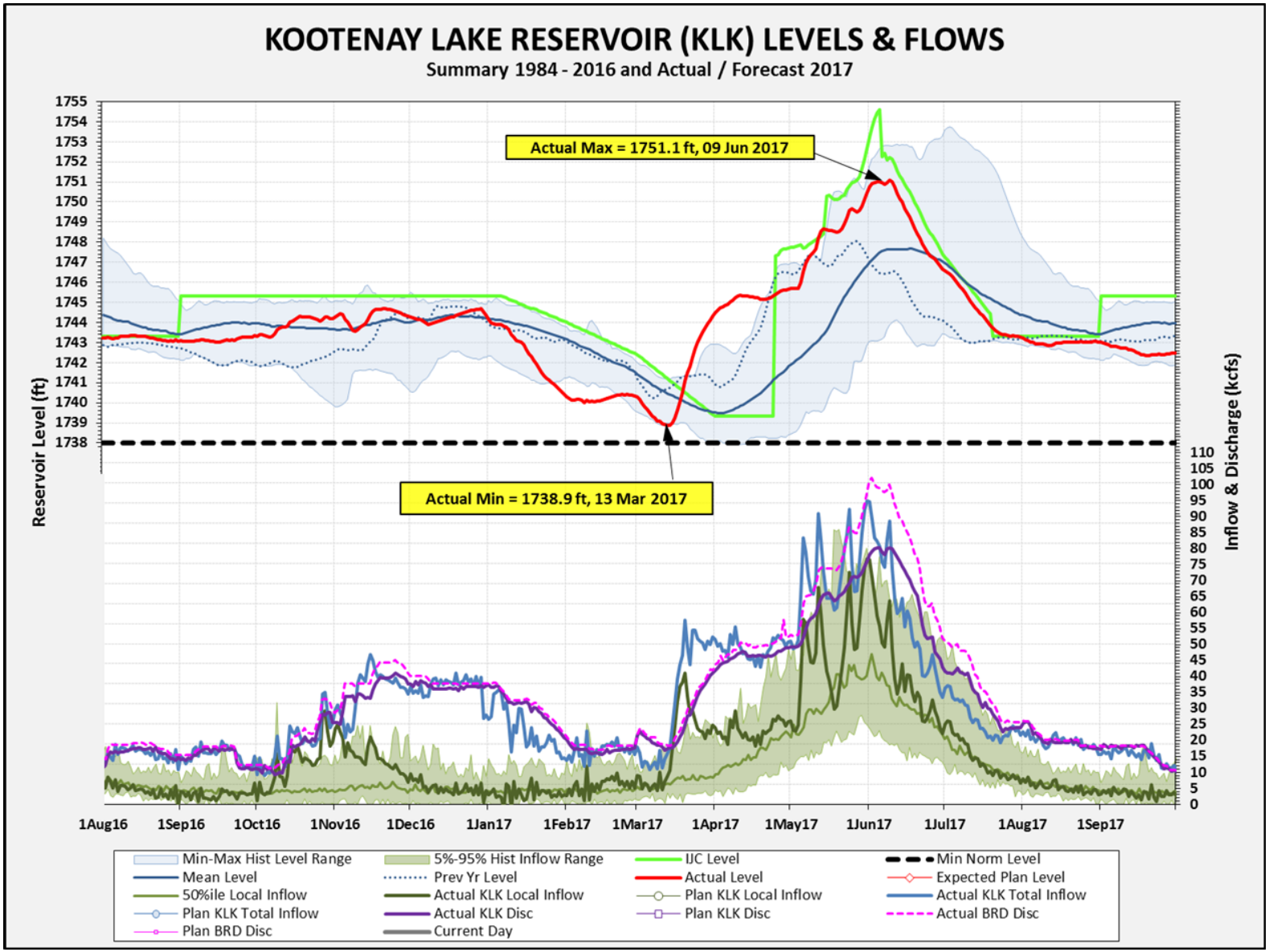


Chart 10: Columbia River at Birchbank

01 August 2016 – 30 September 2017

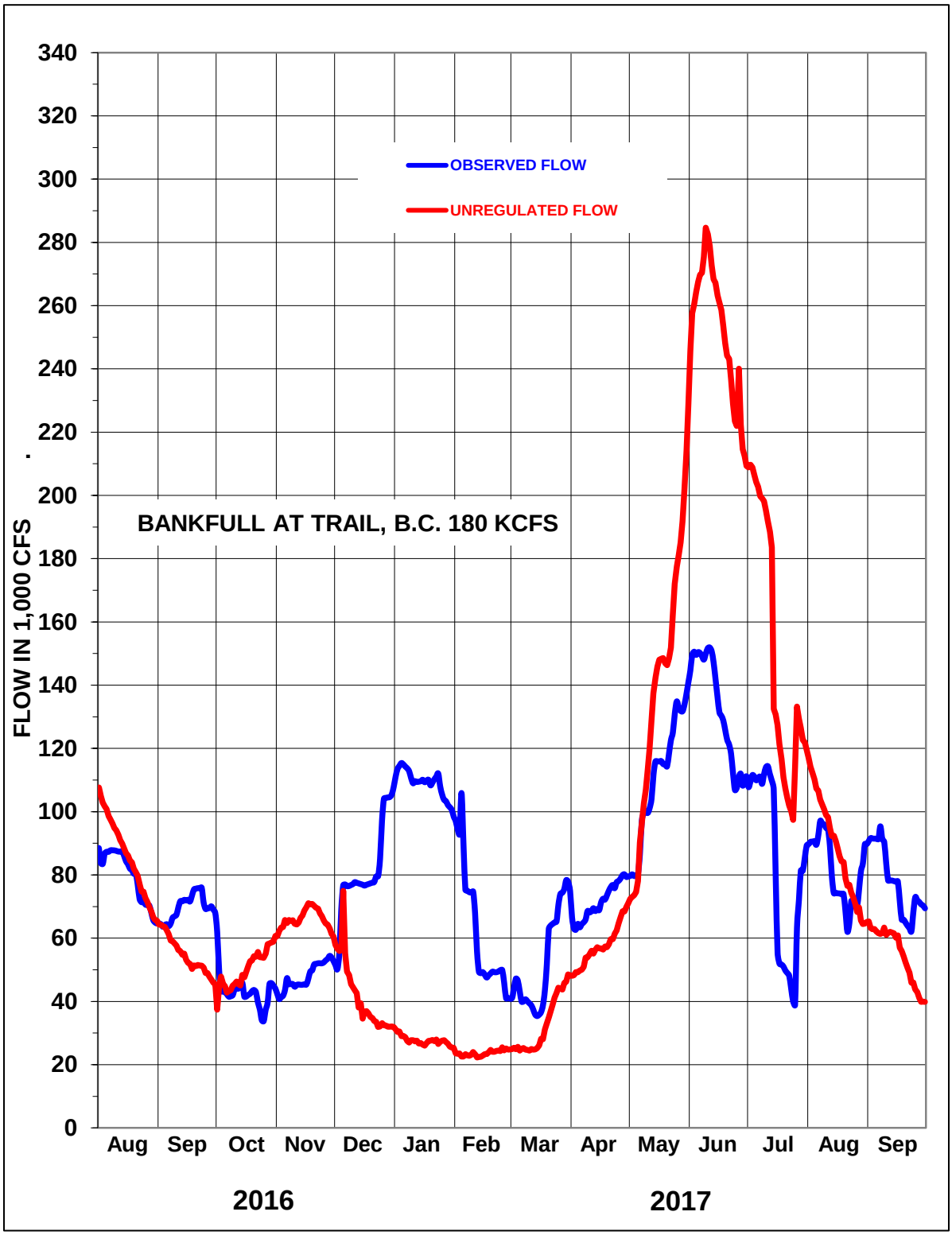


Chart 11: Regulation of Grand Coulee

01 August 2016 – 30 September 2017

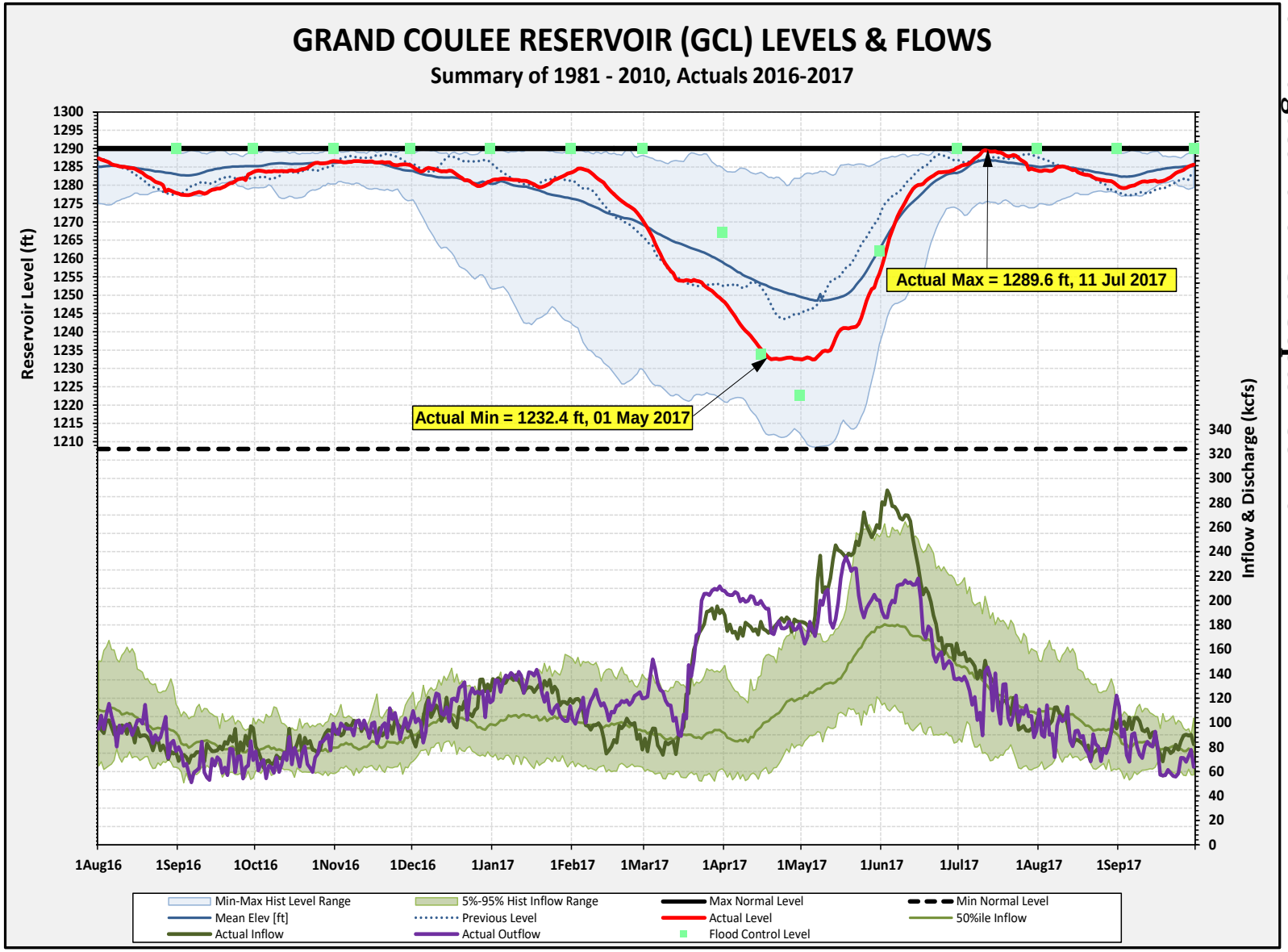


Chart 12: Columbia River at The Dalles (Summary Hydrograph)

01 October 2016 – 30 September 2017

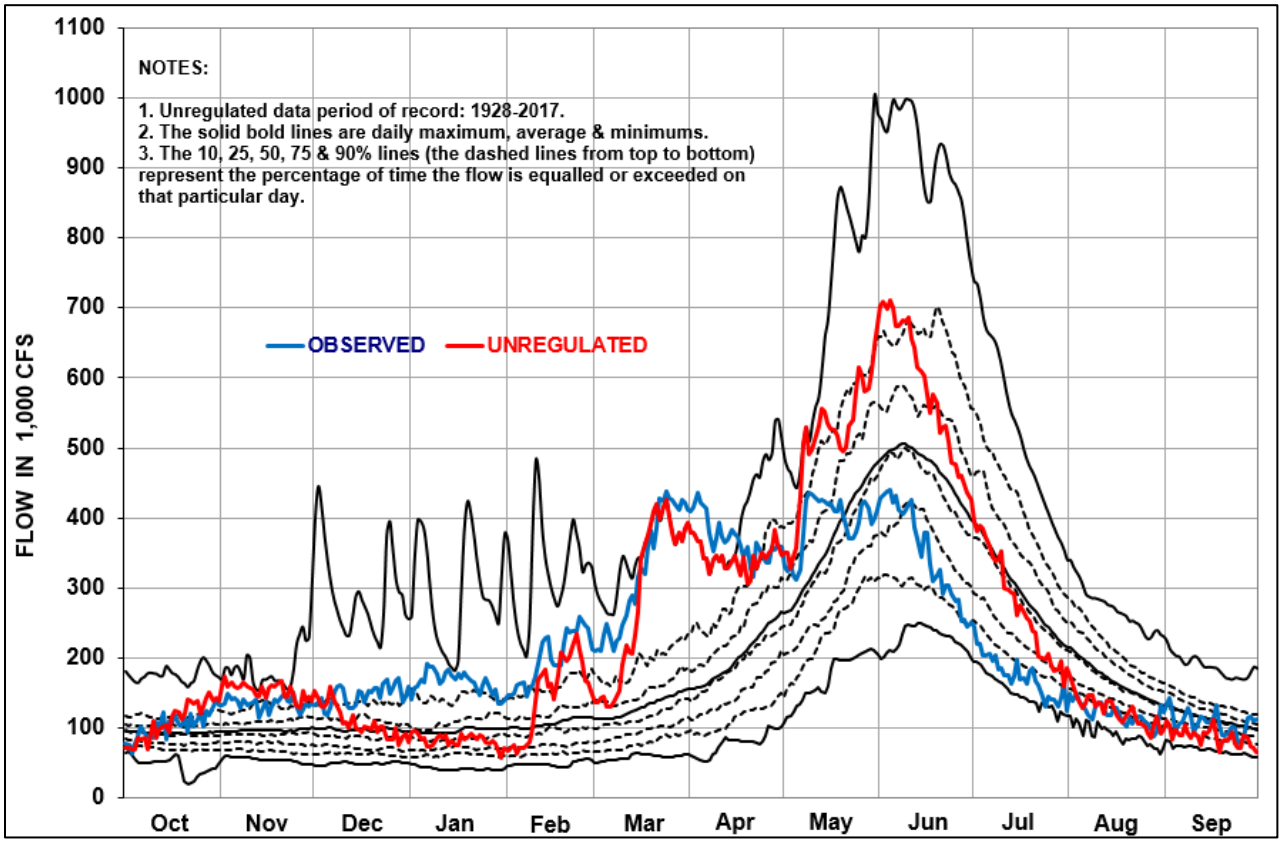
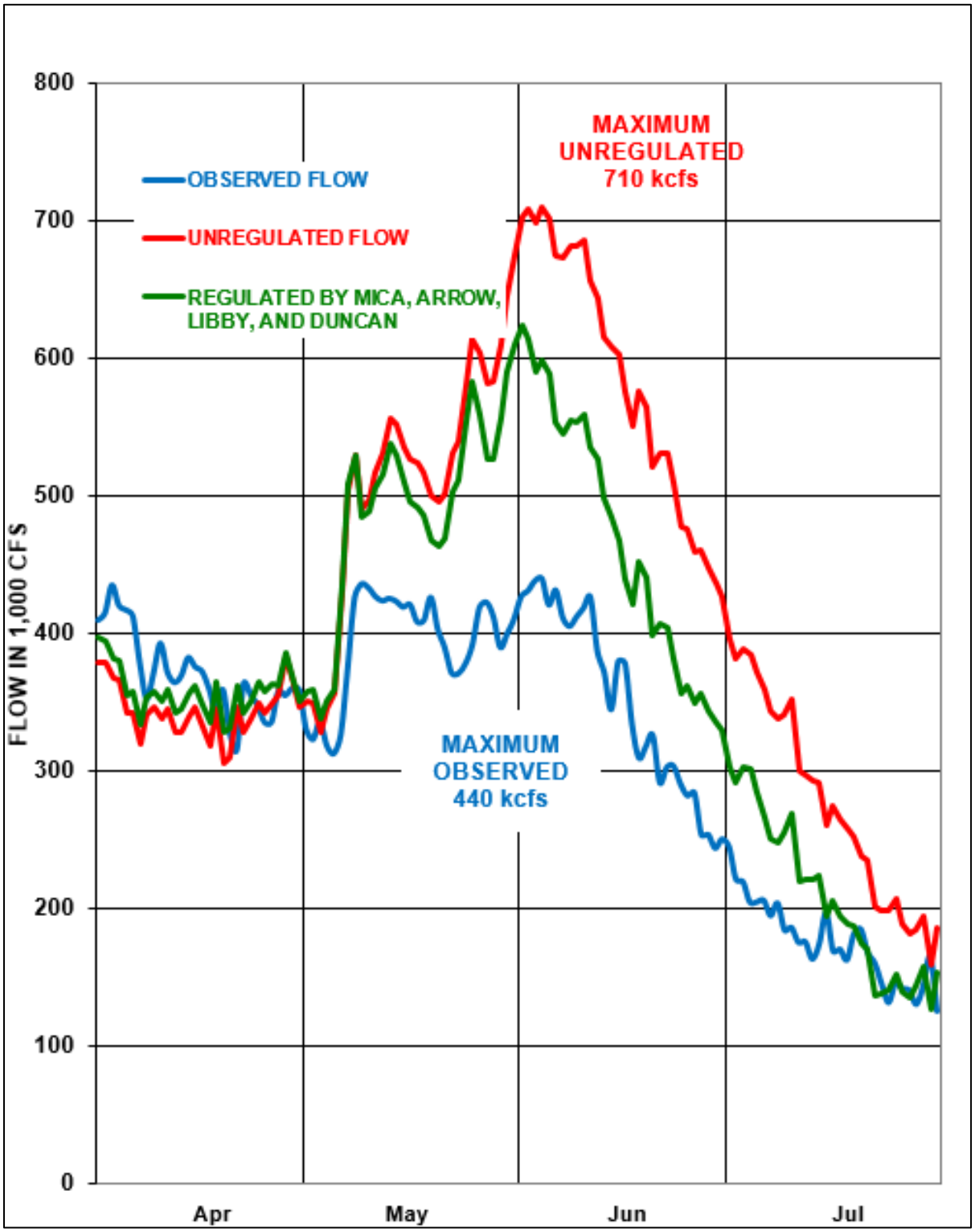



Chart 13: 2017 Columbia River at The Dalles Re-Regulation Plot