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

1 August 2014 through
30 September 2015

2015 ANNUAL REPORT

OF THE

COLUMBIA RIVER TREATY

CANADA AND UNITED STATES ENTITIES

FOR THE PERIOD

1 AUGUST 2014 – 30 SEPTEMBER 2015


Bellingham Herald, Thursday, September 17, 1964

TREATY PACT AGREEMENT SIGNED—In the picture on the left, President Johnson goes through the formality of signing the treaty pact agreement for the Columbia River Treaty. The kibitzers looking over his shoulder are Washington Gov. Albert D. Rosellini and Sen. Henry Jackson. On the right a Canadian official hands Prime Minister Pearson the document while British Columbia Premier W.A.C. Bennett sits beside him ready to blot his signature.—Herald photo.

Treaty Agreement Signing, 1964. *Photo credit: Bellingham Herald*

The Entities dedicate this report to the original Treaty architects whose hard work and dedication brought together two great nations to develop and share the benefits of the mighty Columbia River. These original Treaty coordinators were pioneers in their field and the information in this report is a tribute to their creativity. As we pass the fiftieth anniversary of the Columbia River Treaty, which was signed on 16 September 1964, we reflect on the contributions of the talented staff that has come before us.

CRT 50 Year Celebration Cake by Dania Robinson

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EXECUTIVE SUMMARY

General

Water Year (WY) 2015 was characterized by above normal temperatures which produced below average runoff, marked by a developing El Niño condition and a dry spring. The April-August runoff across the Basin, measured at The Dalles, was 72 km^3 (cubic kilometers) (58.4 Million acre feet, Maf), or 67 percent of the 30 year average (1981 – 2010). April-August runoff in the Upper Columbia (92 percent of normal measured at Keenleyside) and Kootenai basins (72 percent of normal measured at Libby) was below average while runoff in the Snake Basin (54 percent of normal measured at Lower Granite) was well below average. Very warm temperatures started in October 2014 and continued virtually unabated through the summer of 2015. Although below average precipitation across the basin presented its own challenges, the very warm winter caused an unusual amount of the winter precipitation to fall as rain rather than snow, which in the northern half of the basin was actually above normal. That led to near-record high flows in February followed by unusually high March flows, an earlier snowmelt, and near record low flows over the summer months. The result was a below average April-August runoff and an unregulated peak flow at The Dalles of 10,025 m^3/s (cubic meters per second) (354 kcfs [thousand cubic feet per second]). The seasonal regulated peak flow, both at The Dalles and Lower Granite, occurred during February. Since 1960, WY 2015 ranks third driest out of 55 years of record in total April-August runoff as measured at The Dalles.

For the 1 August 2014 through 30 September 2015 reporting period, the Canadian Treaty Projects were operated according to the 2014-2015 and the 2015-2016 Detailed Operating Plans (DOPs), the 2003 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 NOAA Fisheries' 2010 and 2014 Supplemental BiOp for operation and maintenance of the Federal Columbia River Power System.

Entity Agreements

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

- Extension of the Columbia River Treaty Short-term Entity Agreement on Coordination of Libby Project Operations, signed 15 April 2015.

- Columbia River Treaty Entity Agreement on the Detailed Operating Plan (DOP) for Canadian Storage 1 August 2015 through 31 July 2016, signed 26 June 2015.

Columbia River Treaty Operating Committee Agreements

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

- CRTOC Agreement on Operation of Canadian Storage for Nonpower Uses for 1 December 2014 through 31 July 2015 signed on 6 November 2014.
- CRTOC Arrow Summer Storage Agreement for the Period 1 July 2015 through 30 September 2015 signed on 17 July 2015.

System Storage

The 2014-2015 operating year began on 1 August 2014 with the Canadian Treaty storage at 18.6 km^3 (15.1 Maf), or 97.6 percent full. Canadian Treaty storage drafted to a minimum of 5.4 km^3 (4.4 Maf), or 28.4 percent full on 27 March 2015, and refilled to 14.7 km^3 (11.9 Maf), or 76.8 percent full, on 31 July 2015. Canadian Treaty reservoirs operated in proportional draft mode during the second half of August through October 2014 and again during May 2015 through the end of this reporting period to meet Treaty firm loads. Throughout the operating year, composite Canadian Treaty 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. Canadian Treaty storage began the operating year close to the DOP storage levels specified by the TSR study but ended the operating year above TSR specified storage levels under the provisions of the Arrow Summer Shaping Agreement.

As in past years, the CRTOC negotiated a Nonpower Uses Agreement in order to manage Keenleyside outflows and to improve conditions for fish in both countries. Under provisions of that agreement, the U.S. Entity stored 1.23 km^3 (504 thousand second-foot-days (ksfd), 1 Maf) of flow augmentation water during January 2015. 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 during July 2015 to help meet U.S. salmon flow objectives. From January until the end of July 2015, Canadian storage remained above TSR-specified levels.

The January 2015 water supply forecast for the Columbia River above The Dalles for January through July was 126.6 km^3 (102.6 Maf), or 101 percent of the 1981–2010 average. After the water supply forecast increased to 128.0 km^3 (103.8 Maf) in February, or 102 percent of the 1981-2010 average, the spring water supply forecasts at The Dalles decreased as the water year developed. By the June 2015 forecast, the (January-July) runoff forecast had decreased to 106.1 km^3 (86. 0 Maf), or 85 percent of the 1981-2010 average. The actual January through July runoff for the Columbia River above The Dalles was 103.2 km^3 (83.7 Maf), or 83 percent of the 1981-2010 average.

Operations of the three Canadian projects— Mica, Keenleyside, and Duncan — and Libby in the United States are illustrated in Section VIII as Charts 5 through 8 for the 14-month period from 1 August 2014 to 30 September 2015. The hydrographs show actual reservoir levels (Storage Curve) and key rule curves that govern the operations of Treaty storage. The Flood Risk Management Rule Curve specifies maximum month-end reservoir levels which will permit timely evacuation of the reservoir to mitigate potentially high inflows from precipitation and snowmelt events. The First Critical Rule Curve (CRC1) shows the start of the proportional draft that ensures firm power demands can be met under adverse (low) water supply conditions.. The Variable Refill Curve shows the reservoir elevations necessary to ensure refilling of the reservoir by the end of July with a reasonable degree of confidence. The Assured Refill Curve indicates the end-of-month storage content required to assure refill of the reservoir based on the 1931 historical volume of inflow during the refill period.

Treaty Project Operations

Mica (Kinbasket Reservoir)

Kinbasket reached a maximum elevation in 2014 of 753.98 m (2473.7 ft), 0.40 m (1.3 ft) below normal full pool on 6 November 2014, setting a new record high since 1976 for this date. Due to warmer than normal winter temperatures and lack of loads, the reservoir continued to remain at record high levels for most of November through December 2014 and again in late March through mid-June. The reservoir reached a minimum level of 736.98 m (2417.9 ft) on 15 May 2015, 12.19 m (40.0 ft) higher than the 2014 minimum level.

Mica generation also set record levels on several days across the spring and summer. Generation was increased to help support Arrow reservoir levels and for system requirements. From 1 April through 22 August, Mica discharges were approximately 230 percent above average. Despite near normal freshet inflows during the 2014/15 operating year, the significant amount of discharge resulted in Kinbasket not filling to full pool. The reservoir filled to a maximum level of 750.97 m (2463.8 ft) on 15 July 2015, 3.41 m (11.2 ft) below normal full pool. The reservoir drafted over the last half of July, and through to mid-September before leveling off to finish the Operating Year about 3.0 m (10 ft) below average levels.

Hugh Keenleyside (Arrow Lakes Reservoir)

Arrow reached a maximum level of 439.11 m (1440.64 ft), or 1.02 m (3.36 ft) below full pool, on 3 July 2014. Arrow reached a minimum level of 423.82 m (1390.5 ft) on 30 March 2015. By comparison, in the previous year, Arrow reached a minimum level of 427.06 m (1401.1 ft) on 31 January 2014. Toe berm work was completed at Keenleyside in May 2015, allowing the reservoir to surcharge 0.61 m (2.0 ft) if necessary upon approval from Dam Safety (to elevation 440.74 m [1446.0 ft]).

Due to low snowpack and unseasonably low forecast runoff at The Dalles (67 percent of normal April - August runoff at The Dalles), the third driest year since 1960, the Columbia reservoir system in the TSR study was in proportional draft beginning in May and continuing through the reporting period of September 2015. This operation resulted in high discharges from Keenleyside across the spring /summer and produced correspondingly low summer Arrow levels. The reservoir filled to a maximum level of 435.47 m (1428.7 ft), or 4.66 m (15.3 ft) below full pool, on 13 June 2015. Arrow drafted across July, August and September due to continuing proportional draft reaching 428.95 m and 429.04 m (1407.3 ft and 1407.6 ft) by 31 August and 30 September 2015, respectively.

Duncan (Duncan Reservoir)

Duncan refilled to 576.53 m (1891.5 ft), or 0.15 m (0.5 ft) below normal full pool, on 13 August 2014. During the remainder of that month, Duncan was operated to target a reservoir level of 575.46 m (1888.0 ft) for Labour Day 2014. From September 2014 through April 2015, Duncan was operated to supplement inflows into Kootenay Lake, to provide spawning and incubation flows for fish downstream in the Duncan River, and to meet Treaty Flood Risk Management requirements. As in most years, the reservoir was drafted to near empty in late April. Duncan reached its licensed minimum level, 546.90 m (1794.3 ft) on 21 April 2015. By comparison, the reservoir reached a similar minimum level of 546.87 m (1794.2 ft) the year before on 25 April 2014. The reservoir discharge was reduced to its minimum of 3.0 m^3/s (0.1 kcfs) in mid-May to initiate reservoir refill. Releases from Duncan were held at minimum until mid-July, when discharges were gradually increased to manage the rate of reservoir refill. Due to low inflows, Duncan also did not fully refill. By 31 July 2015, the Duncan level reached 574.70 m (1885.5 ft) and the reservoir level peaked at 575.04 m (1886.6 ft), or 1.65 m (5.4 ft) below full, on 3 August 2015. Duncan discharges were increased during August to support Arrow levels during proportional draft operations. To enable this operation, British Columbia Hydro and Power Authority (B.C. Hydro) requested and was granted a variance from the Water Comptroller. The variance allowed Duncan to deviate from the summer recreation target of 575.46 m (1888.0 ft) between 10 August and Labour Day as per the Duncan Water Use Plan Order.

Libby (Lake Koocanusa)

Libby ended July 2014 at elevation 747.64 m (2452.9 ft). The project was drafted to elevation 747.10 m (2451.1 ft) at the end of August 2014, with outflows held constant at 255 m^3/s (9.0 kcfs), the bull trout minimum through the end of August 2014. There was no request from the Kootenai Tribe of Idaho (KTOI) for low flows in the fall of 2014 to assist with the continuing habitat restoration work in the Kootenai River, as had been the case in previous years. For the month of September, releases were maintained above the 170 m^3/s (6.0 kcfs), September bull trout minimum, until elevation 746.46 m (2449.0 ft) was achieved and then releases continued near

255 m^3/s (9.0 kcfs) for most of the month at Bonneville Power Administration's (BPA's) request. The reservoir elevation at the end of September 2014 was 745.97 m (2447.4 ft). The final April – August 2014 inflow volume to the project was 8.3 km^3 (6.7 Maf), or 113 percent of normal (1981 – 2010, 30 year normal).

Releases were reduced to 113 m^3/s (4.0 kcfs) for the month of October and then increased in November to target end of year flood risk management (FRM) goals. The December 2014 water supply forecast for April-August 2015 runoff was 8.5 km^3 (6.9 Maf), or 117 percent of average, requiring the end of December FRM elevation to be 734.87 m (2411.0 ft). The December FRM elevation was reached at the end of the month and releases were set to the 113 m^3/s (4.0 kcfs), the default minimum flow, for the balance of the winter.

Libby's seasonal volume forecasts decreased for the rest of the forecast season and were not sufficiently large to require a Koocanusa draft below the elevation set at the end of December 2014. The water supply forecast for May 2015 was 6.7 km^3 (5.4 Maf), or 92 percent of average. Libby outflow was managed to try to pass inflows for the first part of May since inflows were less than the Variable Flow flood risk management (VarQ) outflow of 513 m^3/s (18.1 kcfs). On 22 May 2015, Libby began to release the sturgeon volume 1.0 km^3 (0.8 Maf) set by the May water supply forecasts and releases were increased to the powerhouse capacity of 750 m^3/s (26.5 kcfs) for 7 days. In 2015, this was a single pulse operation followed by a gradual ramp-down (instead of the double pulse utilized in 2014). Releases were ramped down to 326 m^3/s (11.5 kcfs) on 17 June once the sturgeon volume was expended. The elevation at Libby ended the month of June at 744.57 m (2442.8 ft).

The operation for the rest of the summer, July through August, was to try to refill Libby as best as possible and still meet the 743.41 m (2439.0 ft) target by the end of September, as required in the NOAA BiOp, with The Dalles water supply forecast being below the 20th percentile. Libby reached its peak elevation for the summer on 15 July, 744.96 m (2444.1 ft), which was 4.54 m (14.9 ft) below full pool. Due to low inflow conditions, the project reduced outflow in August to the minimum bull trout flow of 198 m^3/s (7.0 kcfs) and then ramped down to 170 m^3/s (6.0 kcfs), the minimum bull trout flow for September. Libby elevations were 743.93 m (2440.7 ft) and 743.77 m (2440.2 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 in-stream habitat work for the KTOI.

Treaty Benefits

Flood Risk Management Operations

Columbia River Basin projects were operated according to the May 2003 Flood Control Operating Plan. The 2015 water supply forecasts were below normal across the Columbia River Basin. The regulated peak flow[1] during the freshet at The Dalles, Oregon, was 6,300 m^3/s (223 kcfs) on 2 April 2015, and the unregulated peak flow was estimated at 10,025 m^3/s (354 kcfs) on 4 June 2015. The peak stage[2] observed during the freshet at Vancouver, Washington, was 2.23 m (7.3 ft) on 4 April 2015, and the estimated peak unregulated stage was 3.12 m (10.3 ft) on 4 June 2015 while the flood stage is 4.88 m (16.0 ft).

Flood Risk Management Benefits

Water Year 2015 was a quiet flood risk management season due to the low seasonal volumes. There was less snow pack across the basin and less late season rainfall than in previous years resulting in no local flood risk issues. Reservoirs throughout the Columbia River basin, including the Treaty projects, were drafted during the winter and spring in preparation for flood season. The actual runoff for the overall Columbia basin (U.S. and Canada combined) measured at The Dalles for January through July 2015 was 103.2 km^3 (83.7 Maf), 83 percent of normal. The peak regulated and estimated unregulated flows, and river stages are shown in the following tables:

Columbia River Streamflow at The Dalles, Oregon

Date	Peak Unregulated Flow Estimated	Date	Peak Regulated Flow
04 June 2015	10,025 m^3/s (354 kcfs)	02 April 2015	6,300 m^3/s (223 kcfs)[1]

[1] The peak regulated flow at The Dalles during the reporting period was 7,000 m^3/s (2472 kcfs) that occurred on 13 February 2015.
[2] The peak observed regulated stage at the Vancouver gage during the reporting period was 3.3 m (10.81 ft) occurred on 11 February 2015.

Columbia River Stage at Vancouver, Washington

Flood Stage is 4.9 meters (16.0 feet)

Date	Peak Unregulated Stage Estimated	Date	Peak Regulated Stage
04 June 2015	3.12 m (10.3 ft)	04 Apr 2015	2.23 m (7.3 ft)

Hydroregulation by Duncan and Libby projects limited the peak level of Kootenay Lake to 532.55 m (1747.2 ft) on 9 June 2015. Without regulation from those Treaty dams, the peak level would have been approximately 533.7 m (1751.0 ft). As documented in the 2003 Flood Control Operating Plan, flood damages commence at Nelson when the Kootenay Lake elevation reaches 534.92 m (1755.0 ft). Duncan, Keenleyside, Mica and Libby projects limited the peak flow of the Columbia River at Trail, just upstream of Birchbank, British Columbia, to 3,737 m^3/s (132 kcfs) on 14 June 2015. Absent the dams but with natural lake effects at Kootenay Lake, the flow would have been approximately 6,258 m^3/s (~221 kcfs). For reference, the bankfull flow at Birchbank is estimated to be 6,371 m^3/s (225 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 represents one-half of the DDPB. For the period 1 August 2014 through 31 July 2015, the Canadian Entitlement amount, before deducting transmission losses, was 479.9 Average Megawatts (aMW) of energy, scheduled at rates up to 1369 MW. From 1 August 2015 through 30 September 2015, the amount, before deducting transmission losses, was 488.7 aMW of energy, scheduled at rates up to 1332 MW.

During the course of the 2014-2015 Operating Year, the Canadian Entitlement deliveries were completed exactly as scheduled with no curtailment events.

Actual U.S. power benefits from the operation of CRT storage are unknown and can only be roughly estimated. Treaty 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 2014-2015 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 597 aMW. In addition to the increase in average annual U.S. power generation, the Treaty regulation also shifted the timing of generation from the freshet period into the winter months. No quantification of this benefit was reported by the Entities.

Treaty operating plans are designed to adapt to stream flow and water supply conditions that arise and evolve over the Operating Year. Operating Plans are implemented through the TSR study which incorporates stream flows, 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 2014-15 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 flood risk management 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.

Other Benefits

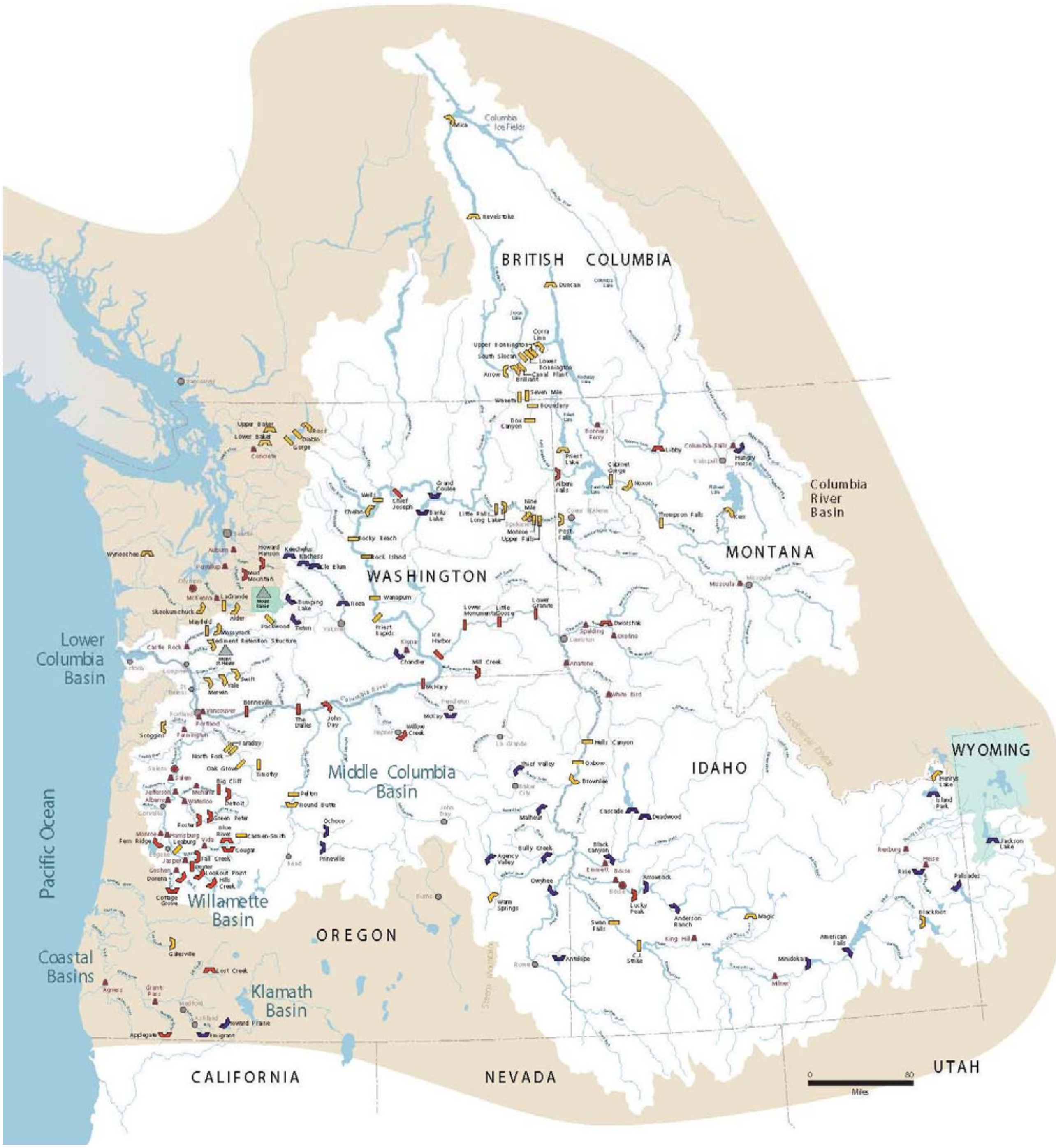
While flood risk management and hydroelectric power generation interests remain the primary factors driving the operation of Treaty storage, the Canadian reservoir draft to provide firm energy during low runoff conditions can be beneficial for other purposes including fisheries benefits. During the near record low flows over the summer months, Canadian CRT reservoirs drafted below their normal refill curves providing higher flows than would have occurred had they been operated to the typical non-drought reservoir levels. Flows from Canadian projects into the U.S. were driven by the following three factors:

1) **Proportional Draft**: During particularly dry periods, the Treaty storage provided in Mica, Keenleyside and Duncan is drafted much more deeply than under normal inflow conditions, to ensure that the U.S. power system is able to produce the agreed firm energy for each month. While these additional Canadian reservoir storage releases, referred to as Proportional Draft, are motivated by the CRT's firm power provisions, they also can provide flows useful for addressing other interests in the U.S. and Canada.

2) **Nonpower Uses (Flow Augmentation) Agreement and Arrow Summer Storage Agreement**: The provisions within the annual CRT Nonpower Uses Agreement provide fisheries benefits in both Canada and the U.S. Under the agreement, 1.23 km^3 (504 ksfd, 1 Maf) of water was stored in Canadian Treaty reservoirs by reducing the Treaty-specified releases in January 2015, outflows from Canadian Storage were shaped through the February – July period to meet multiple needs of both entities, and the stored water was later released during July 2015. Water above the TSR storage level at the end of July was managed through the Arrow Summer Storage Agreement to manage flows into September.

3) **NTSA Dry Year Provisions**: The Non-Treaty Storage Agreement (NTSA) includes a dry year release provision that guarantees to BPA the release of 0.62 km^3 (252 ksfd, 0.5 Maf) from Canadian storage projects during the driest 20 percent of runoff years as measured at The Dalles Dam in the U.S. These dry conditions were met based on the May 2015 volume forecast and BPA requested release of 0.62 km^3 (252 ksfd, 0.5 Maf) of water in May and June per the NTSA.

Columbia Basin Map



2015 Report of the Columbia River Treaty Entities
Table of Contents

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

BG …..Brigadier General

BPA..Bonneville Power Administration

CE…………………………………...Canadian Entitlement

cfs...Cubic feet per second

COL……………………………….... Colonel

CRC..Critical Rule Curve

CRT..Columbia River Treaty

CRTHC ....Columbia River Treaty Hydrometeorological Committee

CRTOC ....Columbia River Treaty Operating Committee

CWR ....B.C. Comptroller of Water Rights

DDPB...Determination of Downstream Power Benefits

DOP..Detailed Operating Plan

DRL..Duncan River below the Lardeau R. confluence

ESP ....Ensemble Streamflow Prediction

FCOP..Flood Control Operating Plans

FRM ....Flood Risk Management

ft ....feet

hm^3 ....Cubic hectometers

in ....inch

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

m ....Meter

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

Maf..Million acre-feet

MW ....Megawatt

MWh ....Megawatt hour

NOAA Fisheries.................................NOAA Fisheries, formerly NMFS

NPU...Nonpower Uses Agreement

NTS ....Non-Treaty Storage

NTSA ....Non-Treaty Storage Agreement

NWRFC ....Northwest River Forecast Center

ORC ....Operating Rule Curve

ORCLL ....Operating Rule Curve Lower Limits

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 Treaty Storage

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

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

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

VRCLL ....Variable Refill Curves Lower Limits

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, but will be referred to in the report as 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) 2015, 1 October 2014 through 30 September 2015, with additional information on the operation of Mica, Keenleyside, Duncan, and Libby dams, as needed, to also cover the reservoir system operating year, 1 August 2014 through 31 July 2015. Also described are the power and flood risk management effects downstream in Canada and the United States (U.S.), as well as the flow augmentation results during the period of significantly lower than average inflows (May – October 2015). This report is the 49th of a series of annual reports covering the period since the ratification of the Columbia River Treaty (Treaty, CRT) in September 1964. The Entities commemorated the 50 year anniversary of the Treaty on 16 September 2014, and a pictorial celebration of this significant event is recorded at the front of this report.

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 flood risk management 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 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 flood risk management 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 19.12 cubic kilometers (km^3) (15.5 Million acre-feet (Maf) of usable storage. This has been accomplished with 8.63 km^3 (7.0 Maf) in Kinbasket, 8.78 km^3 (7.1 Maf) in Arrow, and 1.73 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 flood risk management 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 flood risk management 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 1 April 1968, Keenleyside on 1 April 1969, and Mica on 1 April 1973. That sale has now expired and all Canadian Entitlement 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 4 February 2015 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

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

CANADIAN ENTITY

Mr. Chris O'Riley, Chair
Deputy Chief Executive Office,
British Columbia
Hydro and Power Authority
Vancouver, British Columbia

*BG Spellmon was appointed Commander on 16 July 2015 succeeding BG John S. Kem.

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 BG Spellmon's alternate is the Deputy Division Engineer. The alternate for Mr. O'Riley is the B.C. Hydro Senior Vice President of Generation.

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	**CANADIAN ENTITY COORDINATOR**
Richard Pendergrass Manager, Power and Operations Planning Bonneville Power Administration Portland, Oregon	Renata Kurschner Director, Generation Resource Management B.C. Hydro Burnaby, British Columbia

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

UNITED STATES ENTITY SECRETARY

Birgit G. Koehler*
Regional Coordination
Power and Operations Planning
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY SECRETARY

Douglas A. Robinson
Principle Engineer
Generation Resource Management
B.C. Hydro
Burnaby, British Columbia

* Birgit Koehler was appointed to replace Scott Simms on 11 May 2015.

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

Pamela Kingsbury, BPA, Alt. Chair
Steven B. Barton**, USACE, Alt. Chair
Julie H. Ammann***, USACE
Birgit Koehler, BPA

CANADIAN SECTION

Darren Sherbot*, B.C. Hydro, Chair
Gillian Kong, B.C. Hydro
Herbert Louie, B.C. Hydro
Doug D. Robinson*, B.C. Hydro

* Darren Sherbot replaced Kelvin Ketchum and Doug D. Robinson replaced Alaa Abdalla, both effective as of 16 July 2015.

** Steven Barton was appointed to replace Brad Bird on 19 April 2015; Mr. Bird was appointed to replace William Proctor on 8 February 2015. Mr. Proctor was appointed on 5 January 2015 to replace James Barton who had retired.

*** Julie Ammann was appointed to replace Barbara Miller on 15 June 2015. Ms. Miller replaced Mr. Proctor on 7 January 2015.

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 Canadian Entitlement according to the CRT and related agreements;
- Continued work on the 2019-2020 through 2023-2024 AOP/Determination of Downstream Power Benefits (DDPB);
- Completed the 1 August 2015 through 31 July 2016 DOP;
- Completed two supplemental operating agreements for Canadian storage;
- Implemented the Libby Coordination Agreement (LCA) including the July 2014 update to the Libby Operating Plan, delivery of one average megawatt (MW) of power, and analysis and monitoring of Canadian power effects from Variable flow flood risk management (VarQ) operation at Libby;
- Implemented the Short-term Libby Agreement (STLA) including scheduling Arrow provisional water transactions and associated financial payments;
- Completed the Libby Operating Plan for 2015-2016, July 17, 2015;
- Briefed the PEBCOM on Entity activities, and completed the 2014 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, November 2014. Pictured are (L to R, back row), Trevor Downen, Jim Barton (U.S. Alternate Chair), Robyn MacKay, Bill Proctor (member), Kelvin Ketchum (Canadian Chair), Alaa Abdalla (member), Rob Diffely ,(L to R, front row), Birgit Koehler (member), Peggy Racht, Karl Kanbergs, Doug D. Robinson, Pam Kingsbury (U.S. Alternate Chair), Doug A. Robinson (Secretary), Jeremy Benson

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:

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

* Dr. Georg Jost replaced Dr. Adam Gobena as Canadian Member on 12 January 2015.

** Mr. William Proctor replaced Mr. Peter Brooks on 20 August 2015.

The CRTHC would like to recognize Peter Brooks for his long and outstanding service to the Committee over the last 18 years.

The CRTHC conducted bi-monthly conference calls and met in person twice during the 1 October 2014 – 30 September 2015 period:

Meeting 75: 19 March 2015, BPA

Meeting 76: 19 August 2015, B.C. Hydro

The 2014 CRTHC Annual Report was completed in December 2014 and distributed prior to the annual PEB meeting.

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. There was one deviation requested by B.C. Hydro in the May 2015 forecast for Revelstoke to better reflect the basin conditions at the time. By 1 May, Columbia region snow pack based on 12 stations above 1550 m (roughly the snowline at the time of the survey) was 78 percent of normal. Fall and winter precipitation at one station (Blue River) was reading significantly higher than average and caused a change of +6% on the Revelstoke May forecast. Although the winter precipitation was above normal, it did not translate into above normal snowpack in the basin due to the anomalously warm winter. CRTHC agreed that the Blue River fall and winter precipitation input should be set to 100 percent of normal in the equations in the final May Treaty forecast.

New water supply forecasting procedures for Libby were implemented in 2015. The CRTHC submitted a new version of "Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans for Canadian Treaty Storage" (also referred to as the POP) Appendix 8 which was adopted at the 22 September 2015 CRTOC meeting and incorporated the following changes:

- The hedges were updated to reflect the new Libby Water Supply Forecast procedure and early season statistics (Table 1) for all projects were re-examined to make sure that they correctly reflected the root mean square error (RMSE) around the median. This impacted the hedge computation for many of the projects for the August-November time frame.

- Background documentation was incorporated into Appendix 8 and combined into a single document for easier tracking, with a Table of Contents added to make the longer document easier to navigate.
- There was clarification in the wording describing the computation of hedges and error statistics, and also in the section describing the creation of January-July volumes from statistical forecast periods.
- There was a clarification in the Treaty Storage Regulation (TSR) section (pg. 5) to reflect that for the second TSR in June, the TSR submittal needs to extend past the end of July and include the two halves of August. This brings this section into alignment with POP section 4.4B.

For the past few years, the Northwest River Forecast Center (NWRFC) has produced three Ensemble Streamflow Prediction (ESP) forecasts on a nearly daily basis for various forecast points, each differentiated by the number of days of deterministic weather forecasts used to initialize the forecast. The three initializations currently used are the 10, 5, and 0 days of weather forecast. The CRTHC recommended that the ESP forecast with 5 days of a short-term forecast included be adopted for Treaty purposes and for operational decisions on the Columbia River system. The committee also recommended using the ESP forecast prepared on the 5th working day of each month. In the 22 September 2015 CRTOC meeting, the CRTHC presented these recommendations for the upcoming year, and the recommendations were approved.

Data Exchange

B.C. Hydro completed their transition to secure FTP and all agencies are now receiving Canadian CROHMS data through this more secure channel.

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 will be adding clarification on how it comes to this determination in the 2015 CRTHC Annual Report. One new hydrometric station was added in 2015 to the Nordic headwater basin above Mica. The CRTHC discussed ongoing station data reliability and completeness from the Fernie climate station in B.C., and from the Porthill and Bonners Ferry stations in Idaho.

B.C. Hydro will be installing an automated climate station at Fernie in October 2015. They have requested the observer continue to perform climate observations for a sufficient period of time, so as to compare the collection characteristics and recorded data of the new station to the old station. BPA will provide B.C. Hydro an alternate source for Bonners Ferry and Porthill data to determine if that source will provide more complete data than B.C. Hydro is currently getting.

Permanent Engineering Board

Provisions for the establishment of the 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
Dr. Robert A. Pietrowsky, Alternate Washington, D.C.	Glen Davidson, Alternate Victoria, 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

* Les MacLaren replaced Ivan Harvie effective 15 April 2015.

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 3-4 February 2015 at the Four Seasons Hotel in Vancouver, BC. The Entities and the PEB met to discuss the current status of the 2015 CRT Review, the preparation and implementation of operating plans, the delivery of the Canadian Entitlement and other topics requested by the PEB The Entities reported that the AOP20 would be delayed due to a shift from an energy-limited system to a capacity-limited system in the AOP studies. This could cause a potential 2-3 year delay in completing the AOP studies. The Entities indicated that a detailed plan and schedule for completion of studies would be developed and, when available, would be provided to the PEB Secretaries. It was decided to extend the STLA for one year and during this time Canada would provide the U.S. with suggested changes to Libby operations for evaluation. These evaluations would include impacts on the current Biological Opinion (BiOp) and identification of necessary changes to the Water Control Plan.

PEB Engineering Committee

The PEB has established the PEBCOM to assist in carrying out its duties. The PEBCOM met with the Operating Committee on 22 October 2014 in Portland, Oregon. The members of PEBCOM at the end of this report period were:

UNITED STATES SECTION	CANADIAN SECTION
Jerry W. Webb, Chair Washington, D.C.	Darcy Blais, Chair* Ottawa, Ontario
Thomas Patton, Member Folsom, California	Ivan Harvie, Member** Calgary, Alberta
Kamau B. Sadiki, Member Washington, D.C.	K.T. Shum, Member Victoria, British Columbia
John Roache, Member Boise, Idaho	Chris Trumpy***, Member Victoria, British Columbia

* Mr. Darcy Blais replaced Mr. Ivan Harvie as the Canadian Chair of PEBCOM, effective 15 April 2015

** Ms. Evangelista was appointed to the PEBCOM effective 15 April 2015, but has since left the position. Mr. Harvie continued with his PEBCOM duties through 21 October 2015.

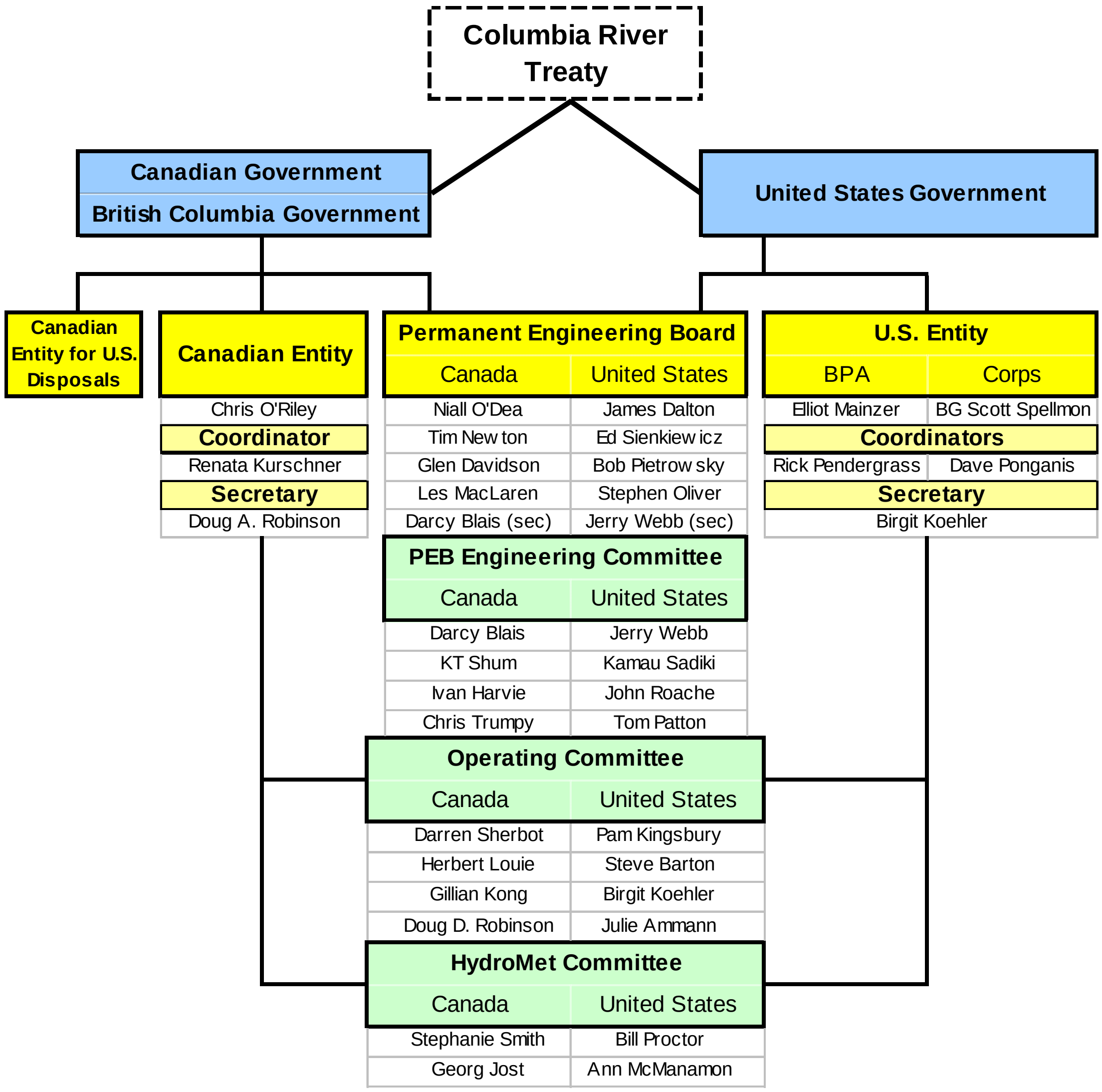
*** Mr. Chris Trumpy was appointed into a vacant Member position effective 20 February 2015.

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 member is 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.

Columbia River Treaty Organization

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 flood risk management and hydroelectric operating plans developed under Annex A of the CRT:

1. Stipulates that the U.S. Entity will submit FCOPs.
2. States that the Canadian Entity will operate in accordance with flood risk management storage diagrams or any variation which the Entities agree will not reduce the desired aim of the flood risk management plan; and
3. Provides for the development of assured hydroelectric operating plans for Canadian storage for the 6^{th} 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 “Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans for Canadian Treaty Storage,” (also referred to as the “POP”) signed December 2003 (as amended), together with the “Columbia River Treaty Flood Control Operating Plan” 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 2014-2015 Operating Year from 1 August 2014 through 31 July 2015. The operation of Canadian storage was guided by the 2014-2015 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 2014-2015 AOP, with agreed changes. Most of the hydrographs and reservoir charts in this report are for a 14-month period from 1 August 2014 through 30 September 2015.

Assured Operating Plans

During the reporting period, the Entities continued work on the 2019-2020 AOP and four subsequent AOPs through AOP 2024. The CRTOC conducted a careful review of the 2019-2020 AOP load and resource assumptions as well as the AOP 2021-2022 load, resource and other data assumptions. The Entities have agreed to a set of assumptions for preparation of the 2019-2020 through 2023-2024 AOPs. Studies are underway and completion of the 2019-2020 through 2023-2024 AOPs is expected in the next reporting period.

Determination of Downstream Power Benefits

For each operating year, the Determination of Downstream Power Benefits (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 initiated studies for the 2019-2020 through 2023-2024 DDPBs.

Canadian Entitlement for the Operating Year

For the period 1 August 2014 through 31 July 2015, the Canadian Entitlement (CE) amount, before deducting transmission losses, was 479.9 Average Megawatts (aMW) of energy, scheduled at rates up to 1369 MW capacity. From 1 August 2015 through 30 September 2015, the amount, before deducting transmission losses, was 488.7 aMW of energy, scheduled at rates up to 1332 MW capacity. The CE obligation was determined by the 2014-2015 and 2015-2016 AOP/DDPBs.

During the course of the 2014-2015 Operating Year, there were no curtailment events for CE deliveries.

Detailed Operating Plans

During the period covered by this report, the CRTOC used the DOP for 1 August 2014 through 31 July 2015, dated June 2014, and the DOP for 1 August 2015 through 31 July 2016, dated June 2015, 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 2014-2015 and 2015-2016 DOPs were based respectively on the 2014-2015 AOP and 2015-2016 AOP loads and resources, rule curves, and other operating criteria with agreed changes for both Canadian and U.S. projects. The 2014-2015 and 2015-2016 AOPs included a flood risk management allocation of 4.44 km^3 (3.6 Maf) at Arrow and 5.03 km^3 (4.08 Maf) at Kinbasket. The 2014-2015 DOP and 2015-2016 DOP operating criteria were used to develop the TSR studies for implementation of Canadian storage operations. The changes from the AOP were mainly updates to flood risk management upper rule curves, hydro-independent data, incorporation of updated forecast errors and distribution factors, plant data, Grand Coulee pumping estimates, and 2010 level modified flows. In addition, the 2015-16 DOP and TSR for the same period incorporated an update to the Grand Coulee storage/elevation table.

The TSR studies were updated twice monthly throughout the reporting period for current inflow forecasts, flood risk management 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 flood risk management requirements, subsequent to 1 January 2015, were determined on the basis of seasonal volume runoff forecasts during actual operation. The VRC calculations for Canadian reservoirs and Koocanusa for the 2014-2015 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 Libby Coordination Agreement (LCA) was supplemented by the Short-Term Libby Agreement on coordination of Libby Project Operations (STLA). The LCA required delivery to the U.S. Entity of one (1) aMW, shaped flat, over the entire 2014-2015 Operating Year. The most recent Libby Operating Plan is dated 17 July 2015. The STLA, signed by the Entities in September 2013, was intended to address, until 31 August 2015, issues raised by the Canadian entity regarding VarQ operations at Libby. The STLA provided the Canadian Entity additional flexibility to draft and store at Arrow. In April 2015, the Entities extended the term of the STLA for one year. 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
15 April 2015	Extension of the Columbia River Treaty Short-term Entity Agreement on Coordination of Libby Project Operations.
26 June 2015	Columbia River Treaty Agreement on the Detailed Operating Plan for Canadian Storage 1 August 2015 through 31 July 2016.

Columbia River Treaty Operating Committee Agreements

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

Date Signed by Entities	Description	Authority
6 November 2014	Columbia River Treaty Operating Committee Agreement on Operation of Canadian Storage for Nonpower Uses for 1 December 2014 through 31 July 2015	Detailed Operating Plan 1 August 2014 through 31 July 2015
17 July 2015	Columbia River Treaty Operating Committee Arrow Summer Storage Agreement For the Period 1 July 2015 through 30 September 2015	Detailed Operating Plan 1 August 2014 through 31 July 2015 and Detailed Operating Plan 1 August 2015 through 31 July 2016

In addition to the Operating Committee agreements listed above, the U.S. Entities (BPA and/or USACE) and B.C. Hydro developed the following bilateral agreements:

- Agreement between BPA and B.C. Hydro that covered the storage, and subsequent release, of Non-Treaty Storage Agreement (NTSA) water during the period 28 February through 31 October 2015, providing mutual power and nonpower benefits during the period.

Long Term Non-Treaty Storage Agreement

The Long Term NTSA, executed in April 2012, was utilized by BPA and B.C. Hydro for power purposes through fall and winter of 2014-15. The Non-Treaty Storage Agreement includes a dry year release provision that guarantees to BPA the release of 0.62 km^3 (252 ksfd, 0.5 Maf) from Canadian storage projects during the driest 20 percent of runoff years as measured at The Dalles Dam in the U.S. These dry conditions were met based on the May 2015 volume forecast and BPA requested release of 0.62 km^3 (252 ksfd, 0.5 Maf) of water in May and June per the NTSA. 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.

IV - WEATHER AND STREAMFLOW

By far the biggest weather story for the 2014-2015 Water Year was from the very warm temperatures, starting in October and continuing virtually unabated through the summer of 2015. Although below average precipitation across the basin presented its own challenges, the very warm winter caused an unusual amount of our winter precipitation, which in the northern half of the basin was actually above normal, to fall as rain rather than snow. That led to near record high flows in February, followed by unusually high March flows, an earlier snowmelt, and near record low flows over the summer months.

For much of the winter, an upper level ridge held over the southwest U.S., while mean troughs were anchored over the western Pacific and northeastern U.S. This directed the jet stream from the subtropical Pacific into the Columbia Basin, and directed a series of storm systems into the region. This storm track led to the fourth year in a row of record drought in California, and increasing drought across the southern portions of Oregon and Idaho. Near this storm track, though, precipitation through March trended above average – particularly across Canada and western Montana (Figure 1). Several of these storms, while being rather warm due to their subtropical origin, were quite strong, most notably ones which affected the region on 8-11 December 2014. Wind gusts as high as 100mph (160km/h) were recorded along the Oregon and Washington Coasts, and between 60-80mph (100-140km/h) west of the Cascades, including Portland, Seattle, and Vancouver.

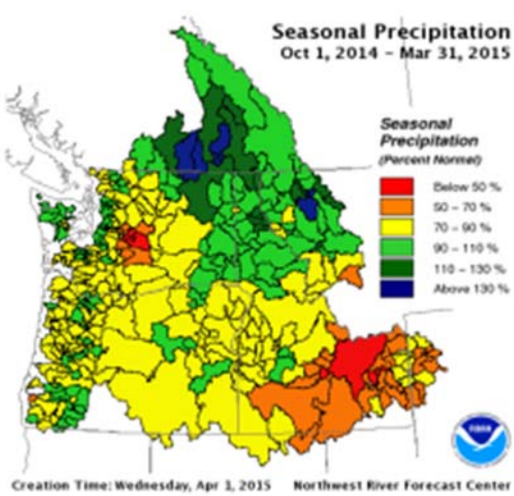


Figure 1: October-March Basin Precipitation. Map source: NOAA/NWS NWRFC.

Despite the periodically heavy precipitation, especially across British Columbia and western Montana, snow levels were not unusually high throughout the winter. In the valleys and deserts, no major snow or ice storms were noted, and only two brief cold snaps were recorded, on 12-16 November and 30 December-2 January. By late February, it was already apparent that the very warm temperatures (with several locations having their warmest February on record) had taken their toll on regional snowpack (Figure 2). The warmth was then accompanied by above average precipitation, which mostly fell as rain in all but the northernmost parts of the basin, and prematurely melted the existing snowpack across the U.S. Basins and the Canadian Kootenay Basin.

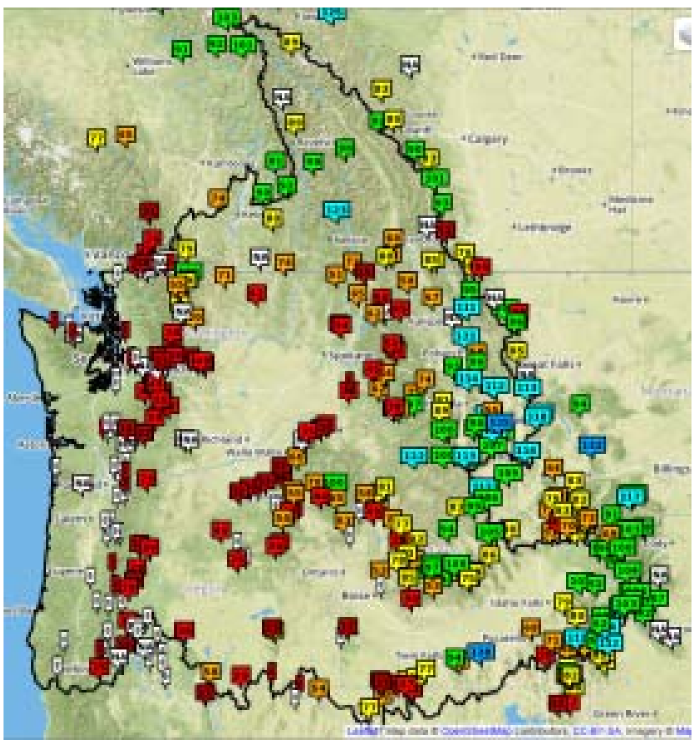


Figure 2: Snow Water Equivalent as a percent of average, 27 February 2015. Map source: NOAA/NWS NWRFC.

It was at this point, in mid-April, when the jet stream began to split around the region to the north and south as a late-developing El Niño took hold over the tropical Pacific. That, in combination with unusually warm waters off the Pacific Northwest coast, led to an unusually hot and dry spring and first part of summer. Between 1 May and 20 July 2015, there were only about six days with below average temperatures for the date. All the other days had temperatures either near or above average. Four significant heat waves were noted across the region from mid-June through early August, with the worst being an 11-day stretch from 26 June through 5 July when temperatures remained 14°F/8°C above average across the basin, and high temperatures in many valleys exceeded 95°F/35°C for a full week. An equally intense heat wave was noted from 30 July through 1 August. These long stretches of heat exacerbated already meager runoff by increasing evapotranspiration. The combination of low flows and hot temperatures resulted in very warm river water temperatures, even in headwater locations and on both regulated and unregulated streams. Warm temperatures in August coupled with lightning strikes, erratic winds, and the underlying drought resulted in dozens of wildfires in the interior Northwest, charring several million acres and degrading air quality throughout the region. September temperatures were generally below normal across much of the basin except for the upper Snake, which remained above normal. Precipitation in September was above normal in the upper Columbia and upper Snake basins and below normal in much of Washington and Oregon.

Columbia Basin Weather

	Temperature	Precipitation	Precipitation	Precipitation
Location	**Columbia Basin above The Dalles** **Departure from the 1981-2010 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 Dalles** **Percent of the 1981-2010 average (%)**
August 2014	+0.8 / +1.4	88%	192%	117%
September 2014	+1.2 / +2.2	91%	108%	90%
October 2014	+ 2.6 / +4.6	118%	60%	98%
November 2014	-0.8 / -1.4	150%	111%	119%
December 2014	+2.2 / +4.0	81%	112%	92%
January 2015	+3.3 / +5.9	80%	53%	64%
February 2015	+ 3.9 / +7.0	111%	80%	92%
March 2015	+3.1 / +5.6	131%	52%	86%
April 2015	+0.2 / +0.4	55%	53%	51%
May 2015	+1.6 / +2.9	63%	129%	97%
June 2015	+4.1 / +7.4	59%	32%	44%
July 2015	+1.1 / +1.9	67%	128%	83%
August 2015	+1.1/ +1.9	78%	56%	64%
September 2015	+0.06/ +0.1	108%	116%	101%
Water Year 2015	**+1.9/ +3.4**	**93%**	**82%**	**84%**

Data, temperature and precipitation maps from NOAA/National Weather Service Northwest River Forecast Center, Portland, OR

Streamflow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 July 2014 through 30 September 2015 are shown 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[3] 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.

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

The peak-unregulated discharge[4] for the Columbia River at The Dalles was 10,025 cubic meters per second (m^3/s) (354 kcfs [thousands of cubic feet per second]) on 4 June 2015, 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 2014-July 2015 streamflow at The Dalles was below average with an equivalent annual runoff volume of 142.0 km^3 (115.1 Maf) (88 percent of 1981-2010 average). This is approximately 16 percent lower than last year's annual runoff.

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-14	90.2	2,555	97	126.8	3,589	102
Sep-14	58.4	1,655	107	86.1	2,437	99
Oct-14	50.7	1,435	112	79.2	2,241	96
Nov-14	63.0	1,784	134	106.9	3,026	113
Dec-14	58.3	1,650	146	116.3	3,295	128
Jan-15	50.2	1,422	125	116.6	3,302	119
Feb-15	93.6	2,651	237	204.1	5,779	177
Mar-15	115.5	3,271	193	194.2	5,498	131
Apr-15	112.5	3,186	97	193.3	5,473	83
May-15	200.9	5,689	80	298.2	8,444	72
Jun-15	204.9	5,801	72	266.4	7,544	61
Jul-15	100.0	2,832	56	122.9	3,479	52
Aug-15	67.1	1,901	72	84.6	2,397	68
Sep-15	65.4	1,853	120	88.1	2,496	101
Aug-Jul Average	**101.8**	**2,882**	**96**	**158.8**	**4,497**	**88**

(Source of unregulated flow = National Weather Service Runoff Processor)

[4] The peak regulated flow at The Dalles during the reporting period was 7,000 m^3/s (247 kcfs) on 13 February 2015

Seasonal Runoff Forecasts and Volumes

Seasonal runoff volumes for the April-August 2015 period, adjusted to exclude the effects of regulation of upstream storage, are listed below for eight locations in the Columbia Basin:

Location	Volume in km^3	Volume in Maf	Percent of 1981-2010 Average
Koocanusa Inflow (Libby Dam)	5.2	4.2	72%
Duncan Inflow	2.2	1.8	88%
Kinbasket Inflow (Mica Dam)	13.6	11.0	100%
Arrow Inflow (Keenleyside Dam)	24.8	20.1	92%
Columbia River at Birchbank	40.1	32.5	84%
Grand Coulee Reservoir Inflow	51.9	42.1	74%
Snake River at Lower Granite	14.1	11.5	54%
Columbia River at The Dalles	72.0	58.4	67%

Source: NWRFC runoff processor

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2015 for a large number of locations in the Columbia River Basin and updated at the beginning of each month from December to July 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 National Weather Service River Forecast Center. The Libby inflow forecast was prepared by the U.S. Army Corps of Engineers. The April 2015 forecast of January through July runoff for the Columbia River above The Dalles was 118.4 km^3 (96.0 Maf) and the actual observed runoff was 103.2 km^3 (83.7 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 (km^3)

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	102.3
2005	105.6	101.6	87.2	91.0	92.1	98.4	100.3
2006	125.0	137.0	132.0	132.0	136.0	137.0	141.0
2007	129.5	124.6	123.3	123.3	122.2	118.9	118.1
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
Minimum	97.7	81.9	72.3	69.2	69.7	68.5	71.8
Median	123.3	122.9	116.3	118.9	120.0	120.8	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
Minimum	79.2	66.4	58.6	56.1	56.5	55.5	58.2
Median	100.0	99.6	94.3	96.4	97.3	97.9	97.7
Maximum	138.0	145.0	142.0	149.0	153.0	159.0	159.0

V - RESERVOIR OPERATION

General

The 2014-2015 Operating Year began with Canadian storage at 97.6 percent full. The Lake Koocanusa level was about 1.86 m (6.1 ft) below full, elevation 747.64 m (2452.9 ft), at the start of the operating year (1 August 2014) and the project was releasing water to meet BiOp objectives for flow augmentation for listed salmon species in the U.S.

The water supply during the 2014-2015 Operating Year was below average in the Columbia Basin above Grand Coulee, and well below average in the Snake River above Lower Granite. The actual runoff in the Canadian portion of the Columbia Basin measured at Birchbank, B.C., was about 95 percent of normal for January through July 2015. The actual runoff for the overall Columbia Basin (U.S. and Canada combined) measured at The Dalles, OR, for January through July 2015 was 83 percent of normal.

The CRTOC signed two operating agreements. The first was the Nonpower Uses Agreement (NPU), for the 2014-2015 Operating Year (see Section III Operating Arrangements) that impacted Mica and Keenleyside operations. The second agreement was the Arrow Summer Storage agreement effective for the period 1 July 2015 through 30 September 2015, impacting Keenleyside and Mica operations.

Canadian Storage Operation

At the beginning of the 2014-2015 Operating Year (1 August 2014), actual Canadian storage provided under Article II of the CRT (Canadian storage) was at 18.6 km^3 (15.1 Maf) or 97.6 percent full. Canadian Treaty storage drafted to a minimum of 5.4 km^3 (4.4 Maf), or 28.4 percent full in 27 March 2015. Canadian composite storage refilled to 14.7 km^3 (11.9 Maf), or 76.8 percent full, at the end of the operating year, 31 July 2015.

The Canadian Treaty composite storage operation was consistent with the DOP TSR for the 2014-15 operating year, as modified by Entity or Supplemental Operating Agreements such as the STLA, Nonpower Uses Agreement and Arrow Summer Shaping Agreement. During the second half of August 2014 through October 2014, and again from May 2015 to current 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 Canadian-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 1 August 2014, Kinbasket level was 752.15 m (2467.7 ft). This was 2.23 m (7.3 ft) below the normal full pool elevation. Kinbasket reached its maximum 2014 elevation of 753.98 m (2473.7 ft), 0.40 m (1.3 ft) below normal full pool on 6 November 2014, setting a new record high for this date since 1976. Higher-than-normal Kinbasket levels in the winter were driven primarily by warmer than normal winter period temperatures and from the lack of load in the system. As a result, the reservoir reached a minimum level of 736.98 m (2417.9 ft) on 15 May 2015, 12.19 m (40.0 ft) higher than the 2014 minimum level. This annual minimum level is also the all-time maximum level for this date.

During the spring and summer, Mica was operated as required for power generation and to support Arrow levels. Since April, Mica generation increased to near record or record highs to meet system requirements and to support Arrow levels during proportional draft periods. Total generation since April was approximately 230 percent of average. The maximum reservoir level reached was 750.97 m (2463.8 ft) on 15 July 2015, 3.41 m (11.2 ft) below normal full pool. At the end of the operating year (31 July 2015) the Kinbasket level was 750.27 m (2461.5 ft).

Inflow into Kinbasket was 107 percent of average over the period August to December 2014. Over this same period, the Mica outflow varied from a monthly average high of about 688 m^3/s (24.3 kcfs) in August 2014 to a monthly average low of about 343 m^3/s (12.1 kcfs) in October 2014. Inflows into Kinbasket were about 106 percent of normal over the period January to July 2015. The Mica discharge over this same period varied from a monthly average high of 1,017 m^3/s (35.9 kcfs) in July to a monthly average low of 473 m^3/s (16.7 kcfs) in March.

Mica had a Treaty underrun of 1.60 km^3 (654.5 ksfd) on 31 July 2014. The maximum underrun for the operating period was 3.13 km^3 (1279.1 ksfd) on 1 September 2014, and the maximum overrun was 1.06 km^3 (433.0 ksfd) on 31 August 2015.

For the reporting period, NTSA water was released and stored by both parties into their respective accounts. Both B.C. Hydro and BPA's NT accounts were refilled to near full by 27 February 2015 and 27 March 2015 respectively. From May 9 through June 26, 2015, BPA exercised its rights to release 0.5 Maf from its NT account under its "Dry Water Provision" due to low runoff forecast at The Dallas as of May.

B.C. Hydro and BPA agreed to a 2015 NT Agreement, utilizing Non-Treaty space at Mica to help reduce drafting of Arrow in February and to reshape flows downstream of Keenleyside for early trout spawning protection flow in March. Under this agreement, BPA did not release an expected 0.24 km^3 (100 ksfd) and stored 0.24 km^3 (97.3 ksfd) of NT water into its account in March 2015. Under this agreement, BPA had rights to release 0.48 km^3 (197 ksfd) from June to October 2015.

Revelstoke

During the 2014-2015 Operating Year, the Revelstoke project was operated primarily as a run-of-river plant, with the reservoir level maintained generally within 1.52 m (5.0 ft) of its normal full pool elevation of 573.02 m (1880.0 ft). During the winter, on occasion, the reservoir operated below its normal low level to provide additional short-term generation, reaching its lowest elevation of 572.08 m (1876.9 ft), or 0.94 m (3.1 ft) below full pool, on 5 January 2015.

Keenleyside

At the start of the operating year on 1 August 2014, the level at Arrow was 436.69 m (1432.7 ft), or 3.44 m (11.3 ft) below the normal full pool level of 440.13 m (1444.0 ft). The reservoir drafted steadily from August through September 2014, refilled temporarily through the first half of October 2014 before drafting again through March 2015, reaching its lowest level for the 2014-2015 operating year, 423.82 m (1390.5 ft), on 30 March 2015 – this was 3.23 m (10.6 feet) lower than the previous year's minimum level on 31 January 2014.

After reaching its minimum level in March 2015, the reservoir refilled from well below normal to above normal from April through June due to a combination of high inflows from snowmelt runoff, increased generation from the Upper Columbia projects, and toe berm construction work below Keenleyside limiting outflows in May. The reservoir reached its maximum level for the year, 435.47 m (1428.7 ft), or 4.66 m (15.3 ft) below normal full pool, on 13 June 2015. The low summer Arrow elevation levels are primarily due to low Columbia basin natural inflows which caused higher proportional draft points in the TSRs and subsequently increased discharges from the Canadian system. Since May 2015, Keenleyside discharges increased from a month average of 841 m^3/s (29.7 kcfs) to about 2,265 m^3/s (80 kcfs) in August 2015. Total discharges for this period were approximately 152 percent of average.

With persistent drought condition in the Columbia basin and increasing proportional draft requirements going into the summer, Arrow drafted quickly from early July into August, with the level reaching 428.95 m (1407.3 ft) on 31 August 2015.

Local inflow into Arrow was 103 percent of average over the period August-December 2014. The Keenleyside discharge varied from a monthly average high of 1767 m^3/s (62.4 kcfs) in August to a monthly average low of 807 m^3/s (28.5 kcfs) in October. Local inflow into Arrow was 93 percent of normal over the period January-July 2015. Outflow over this same period varied from a monthly average low of 490 m^3/s (17.3 kcfs) in April to a monthly average high of 2195 m^3/s (77.5 kcfs) in July.

The CRTOC negotiated a Nonpower Uses Agreement for 2014-15 in order to manage Canadian and U.S. fisheries needs. In January 2015, Arrow Treaty flows were reduced to enable 1.23 km^3 (504 ksfd, 1 Maf) of Flow Augmentation storage as specified under the NPU. Keenleyside actual discharges for January averaged about 1,642 m^3/s (58 kcfs) for the month. During the whitefish incubating months from February through March 2015, flows averaged 1,048 m^3/s (37 kcfs). Even with this flow reduction, the whitefish protection level for January-March 2015 was determined to be “Tier 1” (acceptable), as defined by an arrangement between Canada’s Department of Fisheries and Oceans and B.C. Hydro. The parties mutually agreed to shape February and March flows for better operating conditions. Additional provisions under the NPU maintained Keenleyside discharges during April-June 2015 at or above 481 m^3/s (17 kcfs) to protect rainbow trout spawning downstream of Keenleyside Dam. It should be noted that appearance of rainbow trout spawning started mid-March this year, which is several weeks earlier than normal. All of the water stored for Flow Augmentation under the NPU was released, for U.S. salmon migration, in July 2015.

Due to an increasing proportional draft point in each TSR, the CRTOC negotiated an Arrow Summer Storage Agreement to keep actual flows below 2,322 m^3/s (82 kcfs) in July to help mitigate local concerns and operational issues. The agreement shaped water from July into August under the authority of DOP15 and DOP16. The total amount stored in July was 868 ksfd, which was subsequently released by 28 August 2015.

Under terms of the Short Term Libby Agreement (STLA), B.C. Hydro exercised 291.1 cubic hectometers (hm^3) (119 ksfd) of provisional draft from Keenleyside in August – September 2014. In October - November 2014, B.C. Hydro exercised 0.51 km^3 (210 ksfd) of STLA provisional storage followed by a draft of 102.8 hm^3 (42 ksfd) for one week in November.

Storage by BCH under the STLA took place continuously from 31 January to 13 February 2015. STLA water was released from 28 February to 6 March, and again from 21-27 March to bring the account balance to zero. There was no LCA/STLA activity after 27 March 2015 through to the end of the reporting period, 30 September 2015.

Duncan

Operation of Duncan during the 2014-2015 Operating Year (refer to Chart 7) followed all Treaty requirements and implemented the operational constraints agreed upon in the Duncan Water Use Plan (WUP) and ordered in the Water License Order (issued on 21 December 2007).

Starting 2 September 2014, Duncan discharges were increased to maintain flows in the Duncan River below the Lardeau River confluence (DRL) gauging station at 250 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 decreased during the last week of October 2014 to bring DRL to a maximum flow of 110 m^3/s (3.9 kcfs). These flows were maintained until 21 December, at which point flows were gradually ramped up to bring DRL to about 250 m^3/s (8.8 kcfs) to meet Treaty flood risk management requirements. Duncan discharges were increased above the maximum DRL flow rate of 250 m^3/s (8.8 kcfs) in January and February 2015 in order to draft the reservoir to meet the end-of-month Treaty flood risk management targets of 560.62 m (1839.3 ft) by 31 January and 552.45 m (1812.5 ft) by 28 February 2015.

Duncan was drafted to a minimum level of 546.90 m (1794.3 ft) on 21 April 2015. By comparison, the reservoir reached a similar minimum level of 546.87 m (1794.2 ft) on 25 April 2014. The project was operated to provide minimum flow of 73 m^3/s (2.6 kcfs) at DRL as required for fish until early May when the freshet began and the Duncan discharge was adjusted to ensure DRL flow reductions did not exceed 47 m^3/s (1.7 kcfs) as per Water License requirements.

The reservoir discharge was reduced to a minimum of 3 m^3/s (0.1 kcfs) on 16 May 2015 to begin reservoir refill and manage the level of Kootenay Lake. Releases from Duncan were held at minimum until mid-July to refill the reservoir. Duncan discharges were increased on 14 July 2015 to maintain the DRL minimum flow rate of 73 m^3/s (2.6 kcfs).

On 3 August 2015, the Duncan level peaked at 575.04 m (1886.6 ft), 1.65 m (5.4 ft) below full pool. Duncan discharges were then increased to 184 m^3/s (6.5 kcfs) through August to support Arrow during proportional draft operations as per the Columbia River Treaty. Beginning on 25 September, discharges were ramped down to prepare for the fish spawning flow of 73 m^3/s (2.6 kcfs) during the period 1 - 21 October 2015.

Libby

The operation of Libby and Koocanusa is shown in Chart 8 of this document. Koocanusa ended July 2014 at elevation 747.64 m (2452.9 ft). The project was drafted to elevation 747.1 m (2451.1 ft) at the end of August 2014, with outflows held constant at 255 m^3/s (9.0 kcfs), the bull trout minimum outflow through the end of August for the summer of 2014. There was no request from the Kootenai Tribe of Idaho (KTOI) for low flows in the fall of 2014 to assist with the continuing habitat restoration work in the Kootenai River, as had been the case in previous years. For the month of September, the State of Montana requested outflows be maintained above the 170 m^3/s (6.0 kcfs) September bull trout minimum until elevation 746.46 m (2449.0 ft) was achieved as required by the end of September from the NOAA BiOp. Once the elevation requirement was reached, releases were to be reduced to the bull trout minimum in September. Elevation 746.46 m (2449.0 ft) was crossed on 18 September, but releases were kept at 255 m^3/s (9.0 kcfs) for most of the month at BPA's request. The reservoir elevation at the end of September was 745.97 m (2447.4 ft).

For the month of October, releases were held constant at 113 m^3/s (4.0 kcfs) and Koocanusa filled slightly to 746. 30 m (2448.5 ft). In November, the operation was to regulate Libby to elevation 742.19 m (2435.0 ft) by the end of the month in anticipation of staying within powerhouse capacity in order to meet the end of December flood risk management (FRM) draft target. Releases averaged 445 m^3/s (15.7 kcfs) for the month of November with higher than average inflows 173 m^3/s (6.1 kcfs) due to warm temperatures hindering the accumulation of snow pack. Libby ended the month of November at 742.46 m (2435.9 ft).

The December 2014 water supply forecast for April-August 2015 runoff was 8.5 km^3 (6.9 Maf), or 117 percent of average, requiring the end-of-December FRM elevation to be 734.87 m (2411.0 ft). The December FRM elevation was reached at the end of the month and releases were set to 113 m^3/s (4.0 kcfs), the default minimum flow, for the balance of the winter.

The rest of the winter and early spring saw unusually high temperatures in the Kootenai Basin with snowpack above Libby at 80 percent of average, but the precipitation totals going back to October were at 130 percent of average. Libby's seasonal volume forecasts decreased for the rest of the forecast season and were not sufficiently large to require a Koocanusa draft below the elevation set at the end of December. The May 2015 water supply forecast was 6.7 km^3 (5.4 Maf), or 92 percent of average. Libby refill operations begin as early as ten days prior to the Initial Controlled Flow (ICF) date and refill began on 1 May with an ICF date of 11 May. Libby outflow was managed to pass inflows for the first part of May since inflows were less than the VarQ outflow of 513 m^3/s (18.1 kcfs). On 22 May, Libby began to release the sturgeon volume 1.0 km^3 (0.8 Maf) set by the May water supply forecasts, and releases were increased to the powerhouse capacity of 750 m^3/s (26.5 kcfs) for 7 days. Given the low forecast and subsequent sturgeon volume, there was only a single peak powerhouse release for 7 days. The practice for the previous 2 years was to mimic the hydrology of the basin by peaking Libby twice at powerhouse capacity for two separate 7-day periods in hopes of encouraging spawning recruitment. On 30 May, releases were decreased to 566 m^3/s (20.0 kcfs) and slowly reduced to the June refill flow of 326 m^3/s (11.5 kcfs) on 17 June once the sturgeon volume was expended. The elevation at Libby ended the month of June at 744.57 m (2442.8 ft)

The operation for the rest of the summer, July through August, was to try to refill Libby as much as possible and still meet the 743.41 m (2439.0 ft) target by the end-of-September as required in the NOAA BiOp with The Dalles water supply forecast being below the 20th percentile. Releases were held at 255 m^3/s (9.0 kcfs) for most of the month of July and reduced to the bull trout minimum of 198 m^3/s (7.0 kcfs) by the beginning of August. During the month of July, Libby reached its peak elevation for the summer of 744.96 m (2444.1 ft) which was 4.54 m (14.9 ft) below full pool on 16 July 2015. Projections at the end of the month had the end of September elevations being 0.91 m (3.0 ft) lower than the 743.41 m (2439.0 ft) target with Libby holding the minimum bull trout flows of 198 m^3/s (7.0 kcfs) and 170 m^3/s (6.0 kcfs) in August and September for those months. The operation followed that schedule with August releases averaging 198 m^3/s (7.0 kcfs) and releases reduced to 170 m^3/s (6.0 kcfs) in September. Libby elevations were 743.93 m (2440.7 ft) and 743.77 m (2440.2 ft) at the end of August and September respectively. The 170 m^3/s (6.0 kcfs) outflow in September was also the KTOI-requested release from Libby to help with the in-stream habitat work.

Kootenay Lake

Kootenay Lake is operated (refer to Chart 9) to meet numerous interests, including provision of 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 to September and 453 m^3/s (16 kcfs) during October to November. However, a variance was granted allowing Brilliant to release 396 m^3/s (14.0 kcfs) during the Kootenay Canal geomembrane installation occurring from 5 September to 3 November 2014. In November and December 2014, discharges from the upstream Libby were increased, and Kootenay Lake discharges were then increased, as needed, to control the Kootenay Lake level below the IJC Order maximum level of 531.97 m (1745.32 ft) and prepare for the Brilliant Expansion outage from 18 January to 16 February 2015. Brilliant total releases were maintained at 566 m^3/s (20.0 kcfs) during the Brilliant Expansion outage.

High inflows in February and March caused Kootenay Lake to exceed the IJC maximum level, although in both instances discharges were proactively brought to maximum flow rates through Grohman Narrows. Kootenay Lake drafted to its lowest 2015 level of 530.38 m (1740.1 ft) on 14 March. On 1 April 2015, the Kootenay Lake level was 530.87 m (1741.7 ft), 0.73 m (2.4 ft) above the IJC Order reference level of 530.14 m (1739.32 ft). Despite maximum outflows from the lake, the Kootenay Lake level remained above the IJC Order reference level until the declaration of Spring Rise. 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 2 April 2015. 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 23 May 2015. The level of Kootenay Lake level continued to increase during the April-May period, peaking at 532.55 m (1747.2 ft) on 9 June 2015. By comparison, in 2014, the peak level was 533.49 m (1750.3 ft) on 27 May 2014. Discharge from Kootenay Lake peaked at 1,385 m^3/s (48.9 kcfs) on 2 June 2015, while the Kootenay River discharge at Brilliant peaked at 1,849 m^3/s (65.3 kcfs) on 2 June 2015 due to local inflows from the Slocan River.
On 7 July 2015, Kootenay lake was drafted to 531.36 m (1743.32 ft), at which point the IJC compliance gauge switched from Queens Bay to Nelson and the lake was maintained near 531.27 m (1743.0 ft) through August. Starting in late August, Kootenay Lake was drafted to target 530.96 m (1742.0 ft) by 15 September 2015 for the Kokanee shoal spawning operation.

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, flood risk management, 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 2014-2015 and the 2015-2016 DOPs were 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 nonpower 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 2014 water supply forecast for April-August 2015 runoff was 8.5 km^3 (6.9 Maf), or 117 percent of average (based on the 1981-2010 inflow). Based on this forecast, the recommended draft for Koocanusa was 2.5 km^3 (2.0 Maf), to elevation 734.87 m (2411.0 ft) on 31 December. Libby was operated to its VarQ flood risk management storage reservation diagram. Both Libby and Duncan dams began refill at the beginning of May according to the ICF date.

Flood Risk Management

Overall, the 2015 water supply for the Columbia Basin was below average. The upper Columbia Basin, however, had average flows. The Kootenai Basin seasonal runoff volume was below average. Most of the other sub-basins were below average flows, leading to an observed April-August volume at The Dalles of 72 km^3 (58.4 Maf), which is 67 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 flood risk management 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 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 10,025 m^3/s (354 kcfs) on 4 June 2015, and a regulated daily peak flow for April through July of 6,300 m^3/s (223 kcfs) occurred on 2 April 2015 as measured at The Dalles Dam. The peak regulated flow at The Dalles during the reporting period was 7,000 m^3/s (247 kcfs) which occurred on 13 February 2015 (during the winter and outside the freshet period). The regulated peak stage[5] at Vancouver, Washington, was observed at 2.23 m (7.3 ft) on 4 April 2015 while the flood stage is 4.88 m (16.0 ft). The peak unregulated stage at Vancouver was estimated at 3.12 m (10.3 ft) on 4 June 2015.

For the 2014-2015 Operating Year, the Canadian Entity elected to operate Mica and Keenleyside to the flood risk management 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 flood risk management operation were made in accordance with the Treaty FCOP. For 2015, 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	319.4	9,045
February Forecast	311.1	8,810
March Forecast	264.7	7,497
April Forecast	275.2	7,792
May Forecast	200.0	5,663

[5] The peak observed regulated stage at the Vancouver gage during the reporting period was 3.3 m (10.81 ft) which occurred on 11 February 2015 (during winter and outside freshet period).

Refill at the projects can commence relative to the date when the unregulated flow at The Dalles is expected to equal or exceed the ICF (ICF date). For WY 2015, the ICF date was declared as 10 May based on guidance for initiation of refill in low-flow years developed by the USACE. The flood risk management 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 6,300 m^3/s (223 kcfs), occurring on 2 April 2015. Table 6 shows the data used for the April ICF computation.

Chart 14 shows the relative filling of Arrow and Grand Coulee reservoirs during the refill period and compares real-time regulation to guidelines provided in Chart 6 of the 2003 CRT FCOP. The Grand Coulee pool was drawn down for drum gate maintenance this year, so the chart is less informative for showing the synthetic reservoir balancing between Keenleyside and Grand Coulee. The chart provides more information to the reader in large water years when Keenleyside is drafted for FRM in response to Grand Coulee's FRM draft requirements as a synthetic reservoir. As shown in the chart, starting 30 April 2015, Arrow filled faster relative to Grand Coulee compared to the guideline. Keenleyside was operated to meet local as well as system flood risk management objectives and Grand Coulee was operated for system flood risk management objectives.

Canadian Entitlement and Downstream Power Benefits

From 1 August 2014 through 30 September 2015, the U.S. Entity delivered the Canadian Entitlement to downstream power benefits from the operation of Canadian Treaty 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 1 August 2014 through 31 July 2015, the Canadian Entitlement amount, before deducting transmission losses, was 479.9 aMW of energy, scheduled at rates up to 1369 MW capacity. From 1 August 2015 through 30 September 2015, the amount, before deducting transmission losses, was 488.7 aMW of energy, scheduled at rates up to 1332 MW capacity. The Canadian Entitlement obligation was determined by the 2014-2015 and 2015-2016 AOP/DDPBs. During the course of the 2014-2015 Operating Year, there were no curtailment events for Canadian Entitlement deliveries.

The following Figure 3 shows the historic Canadian Entitlement amounts from the DDPB studies as compared to the estimated amount under the 1964 Canadian Entitlement Exchange Agreement (CEEA).

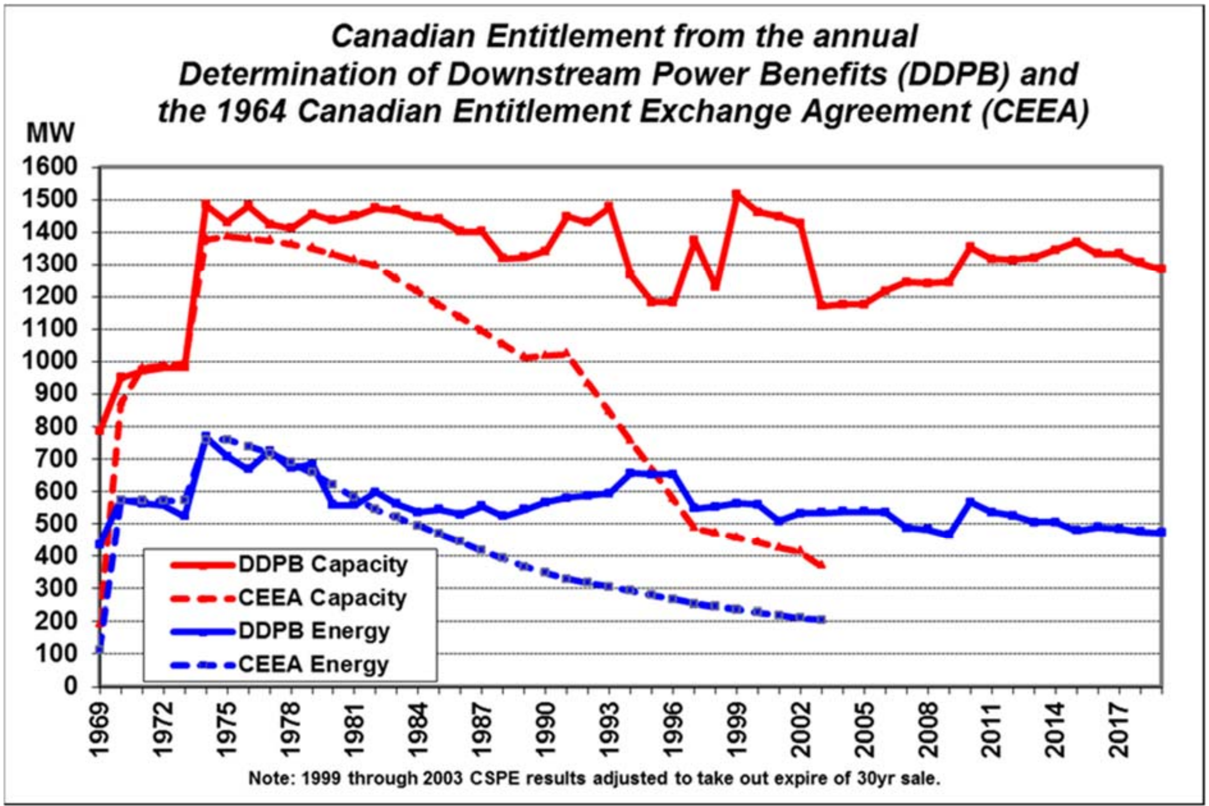


Figure 5: Canadian Entitlements: Agreed CEEA Amounts vs. DDPB Amounts

The Canadian Entitlement Exchange Agreement amounts for the Canadian Entitlement 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 Canadian Entitlement between the historic DDPBs (agreed to annually for the 6th succeeding year) and the Canadian Entitlement 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

Canadian Entitlement (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

Led by the B.C. Treaty Review team, the Canadian Entity completed a series of community meetings in November 2013 to discuss with Basin residents how their interests and feedback had been considered in the draft B.C. recommendations. Results of the additional analysis undertaken in response to previous feedback were also presented specifically related to a mid-elevation constant pool alternative for Arrow and a basin wide ecosystem alternative. The draft B.C. recommendation was released in fall 2013, and, on 13 March 2014, the Honorable Bill Bennett, Minister of Energy and Mines and Minister Responsible for Core Review, announced the release of the Government of British Columbia’s decision to continue the Columbia River Treaty and seek improvements within its existing framework.

B.C.’s decision includes 14 principles that will guide B.C. in any future discussions with Canada and the U.S. on the future of the Treaty. The decision and principles follow more than two years of technical, social, economic and legal studies and an extensive consultation process with various levels of government, stakeholder groups, First Nations and the public. The principles include considerations around flood risk management, hydropower generation, ecosystems and climate change, while allowing for flexibility moving forward to adapt to evolving economic, social and environmental circumstances in each country.

On 13 December 2013 the U.S. Entity transmitted a document called “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 and the three-year process leading up to it 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. Since that time, the review process has resided at the U.S. federal government level.

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 on downstream U.S. power generation during the 2014-2015 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 fishery objectives. The increase in average annual U.S. power generation due to the operation of Canadian storage, as measured by the PNCA AER, was 597 aMW. In addition to the increase in average annual U.S. power generation, the Treaty regulation also shifted the timing of generation from the freshet period into winter months. No quantification of this benefit is provided in this report.

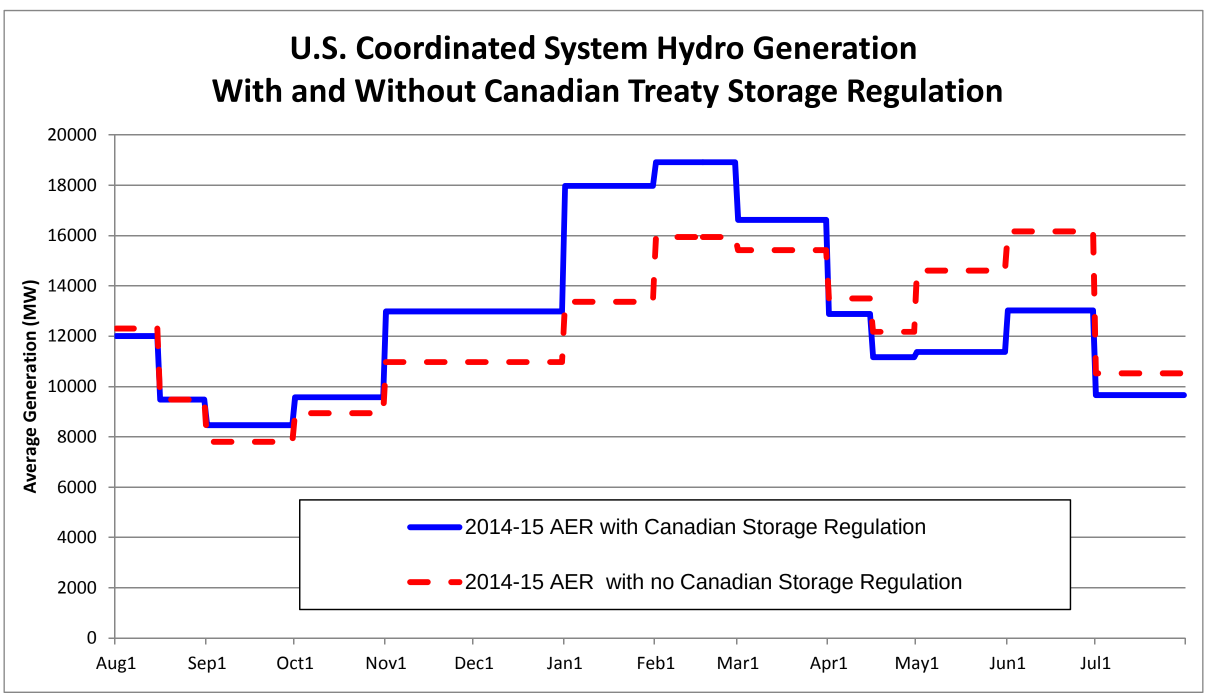


Figure 6: U.S. Coordinated System Hydro Generation

Treaty operating plans are designed to adapt to stream flow and water supply conditions that arise and evolve over the Operating Year. Operating Plans are implemented through the TSR model study which incorporates stream flows, water supply forecasts and operating parameters dependent on runoff conditions during the Operating Year, and which reset the specified Canadian storage draft points twice a month. This report discusses conditions as realized for the 2014-15 Operating Year and describes the response of Canadian storage to the actual inflows and water supply conditions which occurred this 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.

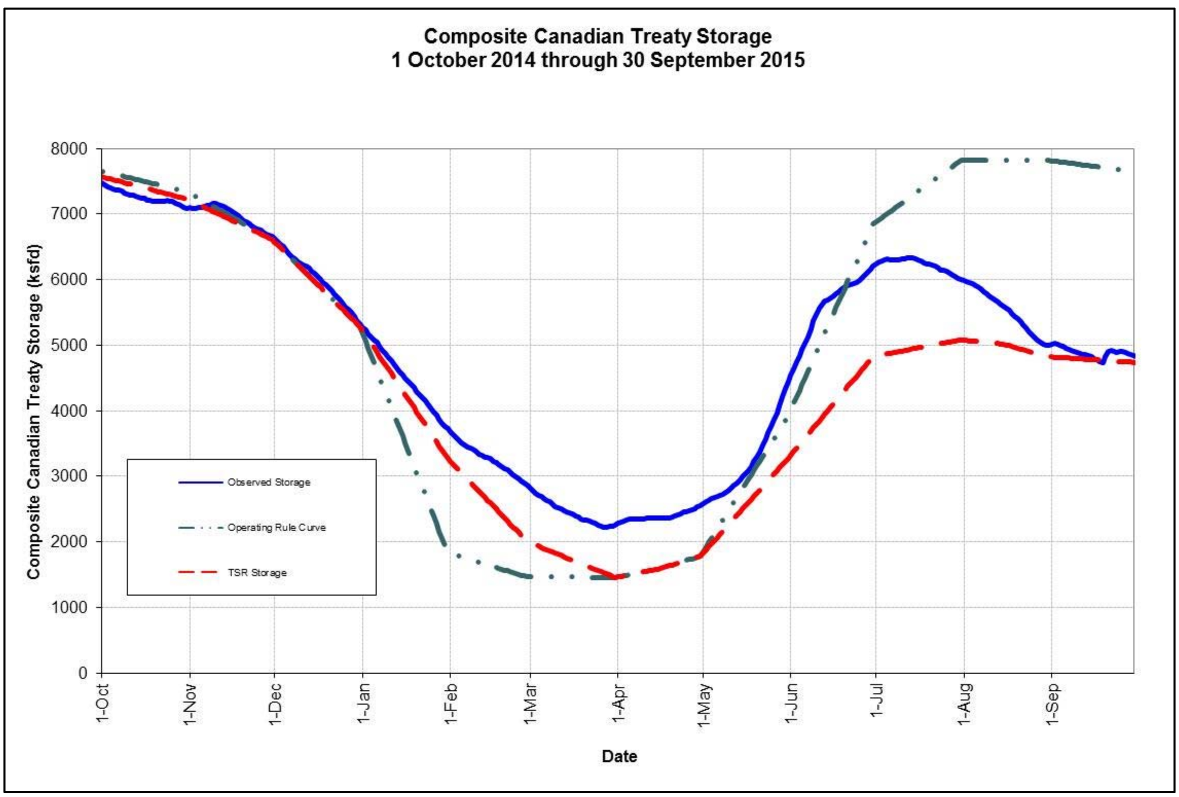


Figure 7: Composite Canadian Treaty Storage

Figure 7 compares the actual operation of the composite Canadian storage to the results of the DOP TSR study. Canadian Treaty reservoirs operated in proportional draft mode during the second half of August through October 2014 and again during May 2015 through the end of this reporting period to meet Treaty firm loads. The STLA Provisional Account was drafted and filled as described in Section V between August 2014 and March 2015. In March the account drafted to the original initial balance and remained there through the end of the Operating Year. Under the 2014-2015 NPU agreement, the U.S. stored 1.23 km^3 (504 ksfd, 1 Maf)) above the TSR for Flow Augmentation in January and maintained that balance until it was released by the end of July. The parties mutually agreed to shape February and March flows for better operating conditions. Also under the NPU agreement, Treaty flows were set low during April through June to support trout spawning which contributed to Treaty Storage being above the TSR during that timeframe. In July, the CRTOC agreed to an Arrow Summer Shaping Agreement to help manage increasing flows from Keenleyside due to the increasing proportional draft. At the end of July, Treaty Storage was above the TSR due to the Arrow Summer Shaping Agreement.

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.

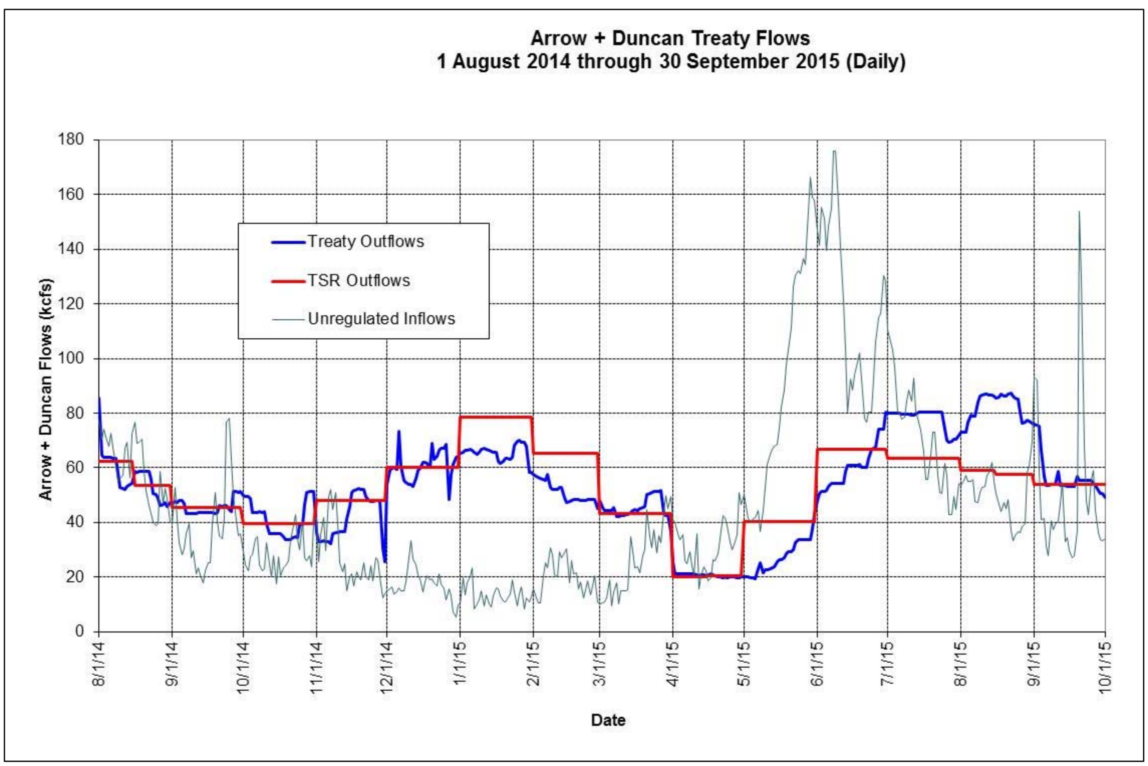


Figure 8: Keenleyside and Duncan Treaty Flows

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 2014 through September 2015

All units in KSFD	2014							2015										
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)	**7752.6**	**7814.6**	**7807.8**	**7578.6**	**7227.7**	**6611.4**	**5282.1**	**3268.5**	**1999.9**	**1456.2**	**1581.1**	**1778.5**	**3272.9**	**4828.0**	**5079.6**	**5013.5**	**4819.8**	**4736.1**
2) Actual Treaty Content (w/SOA's)	7631.2	7713.8	7721.1	7484.7	7086.7	6664.3	5324.1	3722.8	2863.4	2251.3	2362.7	2553.8	4445.8	6211.7	6005.2	5599.1	4993.8	4841.9
3) % full (TSR Comp.Storage/7814.6)	99.2%	100.0%	99.9%	97.0%	92.5%	84.6%	67.6%	41.8%	25.6%	18.6%	20.2%	22.8%	41.9%	61.8%	65.0%	64.1%	61.7%	60.6%
4) Final deviation from TSR	**-121.4**	**-100.8**	**-86.7**	**-93.9**	**-141.0**	**52.9**	**42.0**	**454.3**	**863.5**	**795.1**	**781.6**	**775.3**	**1172.9**	**1383.7**	**925.6**	**585.6**	**174.0**	**105.8**
II. Monthly Accounting of Supplemental Operating Agreements Content (ksfd)																		
	2014							**2015**										
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)	**-84.0**	**-84.0**	**-96.0**	**-203.0**	**-77.0**	**-35.0**	**-35.0**	**-28.0**	**45.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
6) Non Power Uses Flow (NPU) FA	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**504.0**	**504.0**	**504.0**	**504.0**	**504.0**	**504.0**	**504.0**	**0.0**	**0.0**	**0.0**	**0.0**
7) Arrow Summer Shaping Agreement	**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**	**868.0**	**455.0**	**0.0**	**0.0**
8) Total	-84.0	-84.0	-96.0	-203.0	-77.0	-35.0	-35.0	476.0	549.0	504.0	504.0	504.0	504.0	504.0	868.0	455.0	0.0	0.0
9. Inadvertent (Line 4 - Line 8)	**-37.4**	**-16.8**	**9.3**	**109.1**	**-64.0**	**87.9**	**77.0**	**-21.7**	**314.5**	**291.1**	**277.6**	**271.3**	**668.9**	**879.7**	**57.6**	**130.6**	**174.0**	**105.8**
									NPU avg Feb-Mar		**NPU Shaping; inadvertent does not apply**							
III. Summary of TSR Results August 2012-July 2013 (Final TSR in green)																		
Composite Treaty Storage TSR Content (ksfd)																		
	2014							**2015**										2015
TSR Date	JUL	AU1	AU2	SEP	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
7-Aug-14	**7752.6**	7814.6	7808.5	7575.7	7127.5	6566.9	5282.1	3158.4	1734.5	1364.8	1370.3	1546.8	3523.2	6351.5	7752.6			
21-Aug-14		**7814.6**	7810.1	7594.1	7186.5	6611.4	5282.1	3158.4	1734.5	1364.7	1370.2	1533.2	3509.5	6337.9	7752.6			
5-Sep-14			**7807.8**	7551.2	7082.8	6514.7	5282.1	3158.4	1734.5	1364.7	1370.3	1535.2	3511.5	6339.9	7752.6			
19-Sep-14				7398.2	6877.9	6232.4	5219.0	3095.4	1734.5	1253.3	1076.2	1168.7	3145.0	5973.4	7752.6			
6-Oct-14				**7578.6**	7135.4	6491.4	5282.1	3158.4	1734.5	1364.7	1370.2	1561.4	3537.7	6366.1	7752.6			
22-Oct-14					7133.6	6489.1	5282.1	3158.4	1734.5	1364.8	1370.3	1506.2	3482.5	6310.9	7752.6			
6-Nov-14					**7227.7**	6611.4	5282.1	3158.4	1734.5	1364.7	1370.2	1564.3	3540.6	6369.0	7752.6			
19-Nov-14						6611.4	5282.1	3197.0	1734.5	1364.7	1370.2	1556.4	3532.7	6361.1	7752.6			
10-Dec-14						**6611.4**	5282.1	3212.6	1665.6	1340.0	1360.4	1616.2	3592.5	6392.7	7752.6			
18-Dec-14							5282.1	3242.3	1685.9	1360.4	1380.7	1533.4	3509.7	6309.9	7752.6			
13-Jan-15							**5282.1**	3261.3	1704.1	1412.6	1452.1	1665.1	3728.9	6529.5	7752.6			
22-Jan-15								3231.9	1688.7	1390.3	1434.4	1565.4	3624.0	6412.5	7752.6			
11-Feb-15								**3268.5**	1900.2	1446.2	1404.9	1512.0	3566.5	6359.7	7752.6			
23-Feb-15									1974.6	1446.2	1462.3	1568.1	3606.5	6380.7	7752.6			
11-Mar-15									**1999.9**	1456.2	1477.4	1751.8	3877.5	6330.8	7752.6			
25-Mar-15										1456.2	1562.0	1759.4	3809.0	5701.0	7160.6			
13-Apr-15										**1456.2**	1581.1	1778.5	3794.4	6400.9	7752.6			
23-Apr-15											**1581.1**	1778.5	3733.5	6434.1	7752.6			
12-May-15												**1778.5**	2956.6	5190.9	6615.3			
21-May-15													3266.8	5031.3	6474.5			
10-Jun-15													**3272.9**	5585.1	6101.1			
22-Jun-15														5138.8	5968.7	6006.0	5893.9	
9-Jul-15														**4828.0**	5548.8	5516.6	5308.3	
23-Jul-15															5422.1	5403.5	5190.3	4575.2
7-Aug-15															**5079.6**	4956.1	4724.6	4273.4
20-Aug-15																**5013.5**	4799.7	4301.7
4-Sep-15																	**4819.8**	4396.7
18-Sep-15																		4524.2
																		4736.1
Proportional Draft Point (PDP)	1.000	1.000	2.209	2.175	2.107	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.445	2.898	3.723	4.846	4.917	4.776

Figure 9: Summary of Treaty Storage Operation

Other Benefits

While flood risk management and hydroelectric power generation interests remain the primary factors driving the operation of Treaty storage, the Canadian reservoir draft to provide firm energy during low runoff conditions can be beneficial for other purposes including fisheries benefits. During the near record low flows over the summer months, Canadian CRT reservoirs drafted below their normal refill curves providing higher flows than would have occurred had they been operated to the typical non-drought reservoir levels. Flows from Canadian projects into the U.S. were driven by the following three factors:

1) **Proportional Draft**: During particularly dry periods, the Treaty storage provided in Mica, Keenleyside and Duncan is drafted much more deeply than under normal inflow conditions to ensure that the U.S. power system is able to produce the agreed firm energy for each month. While these additional Canadian reservoir storage releases, referred to as Proportional Draft, are motivated by the CRT's firm power provisions, they also can provide flows useful for addressing other interests in the U.S. and Canada.

2) **Nonpower Uses (Flow Augmentation) Agreement and Arrow Summer Storage Agreement**: The provisions within the annual CRT Nonpower Uses Agreement provide fisheries benefits in both Canada and the U.S. Under the agreement, 1.23 km^3 (504 ksfd, 1 Maf) of water was stored in Canadian Treaty reservoirs by reducing the Treaty-specified releases in January 2015, outflows from Canadian Storage were shaped through the February – July period to meet multiple needs of both entities, and the stored water was later released during July 2015. Water above the TSR storage level at the end of July was managed through the Arrow Summer Storage Agreement to manage flows into September.

3) **NTSA Dry Year Provisions**: The Non-Treaty Storage Agreement includes a dry year release provision that guarantees to BPA the release of 0.62 km^3 (252 ksfd, 0.5 Maf) from Canadian storage projects during the driest 20 percent of runoff years as measured at The Dalles Dam in the U.S. These dry conditions were met based on the May 2015 volume forecast and BPA requested release of 0.5 Maf of water in May and June per the NTSA.

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	Keenley side	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.65	29.23	14.50	7.77	107.71
February	2.54	28.79	14.41	6.81	102.51
March	2.46	27.81	13.96	7.01	88.54
April	2.42	27.41	13.50	7.16	89.10
May	2.36	25.62	12.91	6.66	76.97
June	2.33	24.53	12.46	6.28	75.98
Actual	2.18	24.81	13.59	5.24	72.04

Table 1: Unregulated Runoff Volume Forecasts Million Acre-feet

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

First of Month Forecast	Duncan	Keenley side	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.15	23.70	11.76	6.30	87.32
February	2.06	23.34	11.68	5.52	83.11
March	2.00	22.55	11.32	5.68	71.78
April	1.96	22.22	10.95	5.81	72.23
May	1.91	20.77	10.47	5.40	62.40
June	1.89	19.89	10.10	5.09	61.60
Actual	1.77	20.11	11.02	4.25	58.41

Table 2M (metric): 2015 Mica Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			12.0	12.0	11.4	10.7	9.5	6.4
PROBABLE DATE-31JULY INFLOW, hm3	**		12025.0	12019.4	11363.7	10739.6	9484.2	6439.2
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/		10222.4	10742.9	10250.3	9711.7	8502.2	5467.9
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		10222.4					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		4770.9					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		3183.1					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		739.0					
JAN31 ORC, m	7/		739.0					
BASE ECC, m	8/	741.0						
LOWER LIMIT, m		733.0						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		10007.7	10517.3				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		4565.4	4565.4				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		3192.2	2682.6				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		740.0	739.0				
FEB28 ORC, m	7/		735.4	735.4				
BASE ECC, m	8/	735.4						
LOWER LIMIT, m		729.9						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		9762.3	10259.4	9994.1			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0			
MIN APR1-JUL31 OUTFLOW, hm3	4/		4337.8	4337.8	4337.8			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		3210.0	2712.9	2978.3			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		739.1	737.7	738.5			
MAR31 ORC, m	7/		734.5	734.5	734.5			
BASE ECC, m	8/	734.5						
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/		9251.2	9722.3	9471.3	9206.7		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		4117.6	4117.6	4117.6	4117.6		
VRC APR30 RESERVOIR CONTENT, hm3	5/		3500.9	3029.9	3280.9	3545.5		
VRC APR30 RESERVOIR CONTENT, METERS	6/		739.9	738.6	739.3	740.0		
APR30 ORC, m	7/		735.2	735.2	735.2	735.2		
BASE ECC, m	8/	735.1						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		7319.2	7691.9	7493.0	7293.5	6733.7	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0	85.0	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		3890.1	3890.1	3890.1	3890.1	3890.1	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		5205.4	4832.7	5031.7	5231.2	5790.9	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		744.4	743.5	744.0	743.9	745.9	
MAY31 ORC, m	7/		740.4	740.4	740.4	740.4	740.4	
BASE ECC, m	8/	740.4						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		3700.5	3888.9	3792.6	3690.4	3409.4	2766.7
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		623.0	623.0	623.0	623.0	623.0	623.0
MIN JUL1-JUL31 OUTFLOW, hm3	4/		2275.3	2275.3	2275.3	2275.3	2275.3	2275.3
VRC JUN30 RESERVOIR CONTENT, hm3	5/		7209.4	7021.0	7117.3	7219.4	7500.5	8143.1
VRC JUN30 RESERVOIR CONTENT, METERS	6/		749.4	749.0	749.2	749.5	750.2	750.4
JUN30 ORC, m	7/		749.5	749.0	749.2	749.5	750.2	750.4
BASE ECC, m	8/	750.4						
JUL 31 ORC, m			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 (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 FRM REQUIREMENTS
8/HIGHER OF ARC OR CRC1 IN DOP

Table 2: 2015 Mica Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			9748.8	9744.2	9212.6	8706.6	7688.9	5220.3
PROBABLE DATE-31JULY INFLOW, KSFD	**		4915.0	4912.7	4644.7	4389.6	3876.5	2631.9
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/		4178.2	4390.9	4189.6	3969.5	3475.1	2234.9
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		4178.2					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1950.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1301.0					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2424.6					
JAN31 ORC, FT	7/		2424.6					
BASE ECC, FT	8/	2431.0						
LOWER LIMIT, FT		2404.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		4090.4	4298.7				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1866.0	1866.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1304.8	1096.5				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2427.7	2424.5				
FEB28 ORC, FT	7/		2412.6	2412.6				
BASE ECC, FT	8/	2412.6						
LOWER LIMIT, FT		2394.7						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		3990.2	4193.3	4084.9			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1773.0	1773.0	1773.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1312.0	1108.9	1217.3			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2424.9	2420.4	2422.8			
MAR31 ORC, FT	7/		2409.9	2409.9	2409.9			
BASE ECC, FT	8/	2409.8						
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/		3781.3	3973.8	3871.2	3763.0		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1683.0	1683.0	1683.0	1683.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1430.9	1238.4	1341.0	1449.2		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2427.5	2423.3	2425.5	2427.9		
APR30 ORC, FT	7/		2411.9	2411.9	2411.9	2411.9		
BASE ECC, FT	8/	2411.9						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		2991.6	3143.9	3062.6	2981.1	2752.3	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0	3000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		1590.0	1590.0	1590.0	1590.0	1590.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2127.6	1975.3	2056.6	2138.1	2366.9	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2442.3	2439.2	2440.8	2440.5	2447.3	
MAY31 ORC, FT	7/		2429.0	2429.0	2429.0	2429.0	2429.0	
BASE ECC, FT	8/	2429.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1512.5	1589.5	1550.2	1508.4	1393.5	1130.9
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		22000.0	22000.0	22000.0	22000.0	22000.0	22000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		930.0	930.0	930.0	930.0	930.0	930.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2946.7	2869.7	2909.0	2950.8	3065.7	3328.3
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2458.8	2457.3	2458.1	2458.9	2461.2	2461.9
JUN30 ORC, FT	7/		2458.8	2457.3	2458.1	2458.9	2461.2	2461.9
BASE ECC, FT	8/	2461.9						
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 FRM REQUIRMENTS.
8/HIGHER OF ARC OR CRC1 IN DOP

Table 3M (metric): 2015 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			25.7	25.4	24.3	22.8	19.3	12.4
& IN hm3	**		25716.0	25365.4	24349.3	22825.6	19321.5	12354.6
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/		22088.7					
MIN FEB1-JUL31 OUTFLOW, hm3	3/		8570.4					
UPSTREAM DISCHARGE, hm3	4/		5451.5					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		691.1					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		422.0					
JAN31 ORC, m	7/		422.9					
BASE ECC, m	8/	430.0						
LOWER LIMIT, m		422.8						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		21558.6	22141.5				
MIN MAR1-JUL31 OUTFLOW, hm3	3/		8227.9	8227.9				
UPSTREAM DISCHARGE, hm3	4/		6753.3	6753.3				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		2180.5	1597.7				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		426.0	424.5				
FEB28 ORC, m	7/		425.9	424.5				
BASE ECC, m	8/	425.9						
LOWER LIMIT, m		420.2						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		20895.9	21460.9	21354.2			
MIN APR1-JUL31 OUTFLOW, hm3	3/		7848.7	7848.7	7848.7			
UPSTREAM DISCHARGE, hm3	4/		7045.2	7045.2	7045.2			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		2755.9	2190.9	2297.5			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		427.4	426.0	426.3			
MAR31 ORC, m	7/		425.0	425.0	425.0			
BASE ECC, m	8/	420.0						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.9	87.9	90.1	92.8		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		19371.8	19895.5	19769.2	19302.0		
MIN MAY1-JUL31 OUTFLOW, hm3	3/		7481.7	7481.7	7481.7	7481.7		
UPSTREAM DISCHARGE, hm3	4/		6828.9	6828.9	6828.9	6828.9		
VRC APR30 RESERVOIR CONTENT, hm3	5/		3696.7	3173.0	3299.3	3766.5		
VRC APR30 RESERVOIR CONTENT, METERS	6/		429.6	428.4	428.7	429.8		
APR30 ORC, Fm	7/		426.4	426.4	426.4	426.4		
BASE ECC, m	8/	426.4						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		14357.7	14745.8	14661.8	14320.1	13023.8	
MIN JUN1-JUL31 OUTFLOW, hm3	3/		7102.5	7102.5	7102.5	7102.5	7102.5	
UPSTREAM DISCHARGE, hm3	4/		4961.7	4961.7	4961.7	4961.7	4961.7	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		6464.4	6076.2	6160.3	6501.9	7798.2	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		435.6	434.8	435.0	435.7	438.3	
MAY31 ORC, m	7/		433.2	433.2	433.2	433.2	433.2	
BASE ECC, m	8/	433.2						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		6692.9	6873.8	6846.6	6691.1	6090.6	4993.3
MIN JUL1-JUL31 OUTFLOW, hm3	3/		4019.8	4019.8	4019.8	4019.8	4019.8	4019.8
UPSTREAM DISCHARGE, hm3	4/		1425.2	1613.6	1517.3	1415.1	1134.0	1045.9
VRC JUN30 RESERVOIR CONTENT, hm3	5/		7509.9	7517.4	7448.3	7501.6	7821.0	8830.2
VRC JUN30 RESERVOIR CONTENT, METERS	6/		437.7	437.7	437.6	437.7	438.3	438.9
JUN30 ORC, m	7/		437.7	437.7	437.6	437.7	438.3	438.9
BASE ECC, m	8/	439.2						
JUL 31 ECC, m			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 (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 FRM REQUIREMENTS.
8/HIGHER OF ARC OR CRC1 IN DOP

Table 3: 2015 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			20848.1	20563.8	19740.1	18504.8	15664.1	10015.9
& IN KSFD	**		10510.9	10367.6	9952.3	9329.5	7897.3	5049.7
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/		9028.3					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		3503.0					
UPSTREAM DISCHARGE, KSFD	4/		2228.2					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		282.5					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1384.6					
JAN31 ORC, FT	7/		1387.3					
BASE ECC, FT	8/	1410.8						
LOWER LIMIT, FT		1387.3						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		8811.6	9049.9				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		3363.0	3363.0				
UPSTREAM DISCHARGE, KSFD	4/		2760.3	2760.3				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		891.3	653.0				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1397.6	1392.7				
FEB28 ORC, FT	7/		1397.2	1392.7				
BASE ECC, FT	8/	1397.2						
LOWER LIMIT, FT		1378.5						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		8540.8	8771.7	8728.1			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		3208.0	3208.0	3208.0			
UPSTREAM DISCHARGE, KSFD	4/		2879.6	2879.6	2879.6			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1126.4	895.5	939.1			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1402.2	1397.6	1398.5			
MAR31 ORC, FT	7/	1394.5	1394.5	1394.5	1394.5			
BASE ECC, FT	8/	1377.9						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.9	87.9	90.1	92.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		7917.8	8131.9	8080.3	7889.3		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		3058.0	3058.0	3058.0	3058.0		
UPSTREAM DISCHARGE, KSFD	4/		2791.2	2791.2	2791.2	2791.2		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1511.0	1296.9	1348.5	1539.5		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1409.5	1405.5	1406.4	1410.0		
APR30 ORC, FT	7/		1398.8	1398.8	1398.8	1398.8		
BASE ECC, FT	8/	1398.8						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		5868.4	6027.1	5992.7	5853.1	5323.2	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		2903.0	2903.0	2903.0	2903.0	2903.0	
UPSTREAM DISCHARGE, KSFD	4/		2028.0	2028.0	2028.0	2028.0	2028.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2642.2	2483.5	2517.9	2657.5	3187.4	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1429.2	1426.5	1427.1	1429.4	1437.9	
MAY31 ORC, FT	7/		1421.3	1421.3	1421.3	1421.3	1421.3	
BASE ECC, FT	8/	1421.3						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		2735.6	2809.5	2798.4	2734.8	2489.4	2040.9
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		1643.0	1643.0	1643.0	1643.0	1643.0	1643.0
UPSTREAM DISCHARGE, KSFD	4/		582.5	659.5	620.2	578.4	463.5	427.5
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3069.5	3072.6	3044.4	3066.1	3196.7	3609.2
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1436.1	1436.1	1435.7	1436.0	1438.1	1440.0
JUN30 ORC, FT	7/		1436.1	1436.1	1435.7	1436.0	1438.1	1440.0
BASE ECC, FT	8/	1441.1						
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): 2015 Duncan Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			25.7	25.4	24.3	22.8	19.3	12.4
& IN hm3	**		25716.0	25365.4	24349.3	22825.6	19321.5	12354.6
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/		22088.7					
MIN FEB1-JUL31 OUTFLOW, hm3	3/		8570.4					
UPSTREAM DISCHARGE, hm3	4/		5451.5					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		691.1					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		422.0					
JAN31 ORC, m	7/		422.9					
BASE ECC, m	8/	430.0						
LOWER LIMIT, m		422.8						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		21558.6	22141.5				
MIN MAR1-JUL31 OUTFLOW, hm3	3/		8227.9	8227.9				
UPSTREAM DISCHARGE, hm3	4/		6753.3	6753.3				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		2180.5	1597.7				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		426.0	424.5				
FEB28 ORC, m	7/		425.9	424.5				
BASE ECC, m	8/	425.9						
LOWER LIMIT, m		420.2						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		20895.9	21460.9	21354.2			
MIN APR1-JUL31 OUTFLOW, hm3	3/		7848.7	7848.7	7848.7			
UPSTREAM DISCHARGE, hm3	4/		7045.2	7045.2	7045.2			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		2755.9	2190.9	2297.5			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		427.4	426.0	426.3			
MAR31 ORC, m	7/		425.0	425.0	425.0			
BASE ECC, m	8/	420.0						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.9	87.9	90.1	92.8		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		19371.8	19895.5	19769.2	19302.0		
MIN MAY1-JUL31 OUTFLOW, hm3	3/		7481.7	7481.7	7481.7	7481.7		
UPSTREAM DISCHARGE, hm3	4/		6828.9	6828.9	6828.9	6828.9		
VRC APR30 RESERVOIR CONTENT, hm3	5/		3696.7	3173.0	3299.3	3766.5		
VRC APR30 RESERVOIR CONTENT, METERS	6/		429.6	428.4	428.7	429.8		
APR30 ORC, Fm	7/		426.4	426.4	426.4	426.4		
BASE ECC, m	8/	426.4						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		14357.7	14745.8	14661.8	14320.1	13023.8	
MIN JUN1-JUL31 OUTFLOW, hm3	3/		7102.5	7102.5	7102.5	7102.5	7102.5	
UPSTREAM DISCHARGE, hm3	4/		4961.7	4961.7	4961.7	4961.7	4961.7	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		6464.4	6076.2	6160.3	6501.9	7798.2	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		435.6	434.8	435.0	435.7	438.3	
MAY31 ORC, m	7/		433.2	433.2	433.2	433.2	433.2	
BASE ECC, m	8/	433.2						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		6692.9	6873.8	6846.6	6691.1	6090.6	4993.3
MIN JUL1-JUL31 OUTFLOW, hm3	3/		4019.8	4019.8	4019.8	4019.8	4019.8	4019.8
UPSTREAM DISCHARGE, hm3	4/		1425.2	1613.6	1517.3	1415.1	1134.0	1045.9
VRC JUN30 RESERVOIR CONTENT, hm3	5/		7509.9	7517.4	7448.3	7501.6	7821.0	8830.2
VRC JUN30 RESERVOIR CONTENT, METERS	6/		437.7	437.7	437.6	437.7	438.3	438.9
JUN30 ORC, m	7/		437.7	437.7	437.6	437.7	438.3	438.9
BASE ECC, m	8/	439.2						
JUL 31 ECC, m			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/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 FRM REQUIREMENTS.
8/HIGHER THAN THE ARC OR CRC1 IN DOP

Table 4: 2015 Duncan Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			1850.4	1788.3	1710.9	1619.5	1465.2	1000.3
& IN KSFD	**		932.9	901.6	862.6	816.5	738.7	504.3
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/		806.6	797.3	757.6	722.6	651.8	426.3
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		806.6					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		120.1					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		19.3					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1798.8					
JAN31 ORC, FT	7/		1817.8					
BASE ECC, FT	8/	1838.2						
LOWER LIMIT, FT		1817.8						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.1	98.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		790.5	781.3				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		117.3	117.2				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		32.6	41.7				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1801.6	1803.4				
FEB28 ORC, FT	7/		1801.6	1803.4				
BASE ECC, FT	8/	1834.2						
LOWER LIMIT, FT		1795.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.7	95.7	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		771.1	762.2	739.4			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		114.2	114.1	115.3			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		48.9	57.7	81.7			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1804.7	1806.4	1810.6			
MAR31 ORC, FT	7/		1804.7	1806.4	1808.2			
BASE ECC, FT	8/	1836.2						
LOWER LIMIT, FT		1794.2						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.7	89.7	91.6	93.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		722.7	714.4	693.2	677.1		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0	100.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		111.2	111.1	112.3	111.9		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		94.3	102.6	124.9	140.6		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1812.7	1814.0	1817.7	1820.2		
APR30 ORC, FT	7/		1807.8	1807.8	1808.2	1811.7		
BASE ECC, FT	8/	1839.8						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.5	67.5	69.0	70.6	75.3	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		542.9	536.6	520.5	508.0	489.5	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0	100.0	100.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		108.1	108.0	109.2	108.8	109.9	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		271.1	277.3	294.6	306.6	326.2	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1839.0	1839.8	1842.1	1843.8	1846.3	
MAY31 ORC, FT	7/		1839.0	1839.8	1842.1	1843.8	1846.3	
BASE ECC, FT	8/	1860.1						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			32.5	32.5	33.3	34.0	36.3	48.2
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		261.4	258.3	250.8	244.3	235.9	205.1
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		1118.1	1124.5	1120.7	1161.1	1146.7	1182.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		74.4	74.4	74.4	74.4	74.4	74.4
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		518.8	521.9	529.4	535.9	544.3	575.1
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1870.4	1870.7	1871.6	1872.4	1873.4	1877.0
JUN30 ORC, FT	7/		1870.4	1870.7	1871.6	1872.4	1873.4	1877.0
BASE ECC, FT	8/	1886.3						
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 FRM REQUIREMENTS.
8/HIGHER OF ARC OR CRC1 IN DOP

Table 5M (metric): 2015 Libby Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			7.9	7.2	7.4	7.8	7.4	7.4
PROBABLE DATE-31JULY INFLOW, hm3			7858.5	7170.3	7449.2	7827.7	7365.2	7022.2
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	285.0	705.6	1305.0	2014.3	3629.0
95% CONF.DATE-31JULY INFLOW, hm3	1/		5612.5	5072.0	5021.6	5271.9	4133.5	2206.8
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		5438.3					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		2593.4					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		3297.3					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		732.2					
JAN31 ORC, m	7/		732.2					
BASE ECC, m	9/	738.0						
LOWER LIMIT, m		718.3						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		5281.2	4925.0				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		2319.4	2319.4				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		3180.3	3536.6				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		731.3	733.9				
FEB28 ORC, m	7/		731.3	733.9				
BASE ECC, m	9/	737.1						
LOWER LIMIT, m		710.0						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.6	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		5084.8	4742.5	4835.7			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3			
MIN APR1-JUL31 OUTFLOW, hm3	4/		2016.0	2016.0	2016.0			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		3073.4	3415.7	3322.5			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		730.5	733.0	732.4			
MAR31 ORC, m	7/		730.5	733.0	732.4			
BASE ECC, m	9/	736.4						
LOWER LIMIT, m		699.0						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.4	85.0	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		4624.6	4311.4	4393.8	4792.2		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3	113.3		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		1722.4	1722.4	1722.4	1722.4		
VRC APR30 RESERVOIR CONTENT, hm3	5/		3240.0	3553.2	3470.7	3072.4		
VRC APR30 RESERVOIR CONTENT, METERS	6/		731.8	734.0	733.4	730.5		
APR30 ORC, m	7/		731.8	734.0	733.4	730.5		
BASE ECC, m	9/	736.1						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.3	57.0	58.7	61.0	62.9	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		3103.8	2891.1	2947.7	3215.8	3316.1	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		254.9	254.9	254.9	254.9	254.9	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		1419.0	1419.0	1419.0	1419.0	1419.0	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		4457.5	4670.1	4613.6	4345.4	4245.1	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		739.9	741.2	740.9	739.2	738.6	
MAY31 ORC, m	7/		739.9	741.2	740.9	739.2	738.6	
BASE ECC, m	9/	743.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.8	20.3	20.9	21.8	22.4	23.9
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		1111.2	1029.5	1049.6	1149.2	1181.0	987.9
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		283.2	283.2	283.2	283.2	283.2	283.2
MIN JUL1-JUL31 OUTFLOW, hm3	4/		758.4	758.4	758.4	758.4	758.4	758.4
VRC JUN30 RESERVOIR CONTENT, hm3	5/		5789.4	5871.1	5851.0	5751.2	5719.7	5912.7
VRC JUN30 RESERVOIR CONTENT, METERS	6/		747.6	748.0	747.9	747.4	747.2	748.3
JUN30 ORC, m	7/		747.6	748.0	747.9	747.4	747.2	748.3
BASE ECC, m	9/	749.5						
JUL 31 ORC, m			31.3	31.6	28.0	29.3	26.3	26.3
JAN1-JUL31 FORECAST,-EARLYBIRD, km3	8/		118.5	98.7	125.9	129.4	135.2	132.8

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: 2015 Libby Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE JAN-31JULY INFLOW, KAF			5560	5287	5566	6837	6953	7024
PROBABLE JAN-31JULY INFLOW, KSFD			2803.2	2665.5	2806.2	3447	3505.5	3541.3
95% FORECAST ERROR FOR DATE, KSFD			774.3	535.9	490.6	432.3	390.8	342.2
OBSERVED JAN1-DATE INFLOW, IN KSFD			0	96.3	164.9	293.9	527.4	1589.6
95% CONF.DATE-31JULY INFLOW, KSFD	1/		2028.9	2033.3	2150.7	2720.8	2587.3	1609.5
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		1966					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4000					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1370.4					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1914.9					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2432					
JAN31 ORC, FT	7/		2420.8					
BASE ECC, FT	9/	2421.4						
LOWER LIMIT, FT		2356.6						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		1909.2	1974.3				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1258.4	1283				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1859.7	1819.2				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2429.4	2427.4				
FEB28 ORC, FT	7/		2418.1	2418.1				
BASE ECC, FT	9/	2418.4						
LOWER LIMIT, FT		2329.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.6	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		1838.2	1901.1	2071.1			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000	4000			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1134.4	1159	999.8			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1806.7	1768.4	1439.2			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2426.7	2424.8	2407.4			
MAR31 ORC, FT	7/		2415.3	2415.3	2407.4			
BASE ECC, FT	9/	2416.0						
LOWER LIMIT, FT		2293.4						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.4	85	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		1671.8	1728.3	1881.9	2473.2		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000	4000	4000		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1014.4	1039	879.8	818.7		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1853.1	1821.2	1508.5	856		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2429.1	2427.5	2411.3	2369.1		
APR30 ORC, FT	7/		2414.4	2414.4	2411.3	2369.1		
BASE ECC, FT	9/	2415.1						
		2287.0						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.3	57	58.7	61	67.1	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		1122	1159	1262.5	1659.7	1736.1	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		14484.3	15000	11664.3	10382.3	8206.7	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		890.4	915	755.8	694.7	590.9	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2278.9	2266.5	2003.9	1545.5	1365.3	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2448.9	2448.3	2436.3	2413.3	2403.2	
MAY31 ORC, FT	7/		2437.2	2437.2	2436.3	2413.3	2403.2	
BASE ECC, FT	9/	2437.6						
		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/		401.7	412.8	449.5	593.1	618.4	573
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		14705.3	15000	13093.9	12361.3	11118.1	11626.1
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		455.9	465	405.9	383.2	344.7	360.4
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2510.5	2510.5	2466.9	2300.6	2236.8	2297.9
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2459	2459	2457.1	2449.9	2447	2449.8
JUN30 ORC, FT	7/		2459	2459	2457.1	2449.9	2447	2449.8
BASE ECC, FT	9/	2437.6						
		2287.0						
JUL 31 ORC, FT			2459.00	2459.00	2459.00	2459.00	2459.00	2459.00
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		96.1	80.0	102.1	104.9	109.6	107.7

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 6: Computation of Initial Controlled Flow

Columbia River at The Dalles, OR

Metric and English Units, based on May 2015 forecast

Upstream Storage Corrections	**Metric (km^3)**	**English (Maf)**
Mica	6.526	5.291
Arrow	4.441	3.600
Duncan	1.704	1.382
Libby	2.009	1.628
Hungry Horse	0.602	0.488
Flathead Lake	0.617	0.500
Noxon Rapids	0.000	0.000
Pend Oreille Lake	0.617	0.500
Grand Coulee	0.662	0.537
Brownlee	0.354	0.287
Dworshak	0.309	0.250
John Day	0.195	0.158
Total Upstream Storage Corrections	18.034	14.621

Adjusted TDA May-Aug Runoff Volume	**Metric (km^3)**	**English (Maf)**
TDA May-Aug Runoff Volume (1May Forecast)	62.777	50.894
Less Estimated Depletions	-2.502	-2.028
Less Total Upstream Storage Corrections	-18.034	-14.621
Adjusted TDA May-Aug Runoff Volume	42.241	34.245

Initial Controlled Flow	**m^3/s**	**kcfs**
Determined using 'Adjusted TDA May-Aug Runoff Volume' and Chart 1 of the Flood Control Operating Plan	**5663.4**	**200.0**

VIII - CHARTS

Chart 1: Pacific Northwest Monthly Temperature Departures

October – March

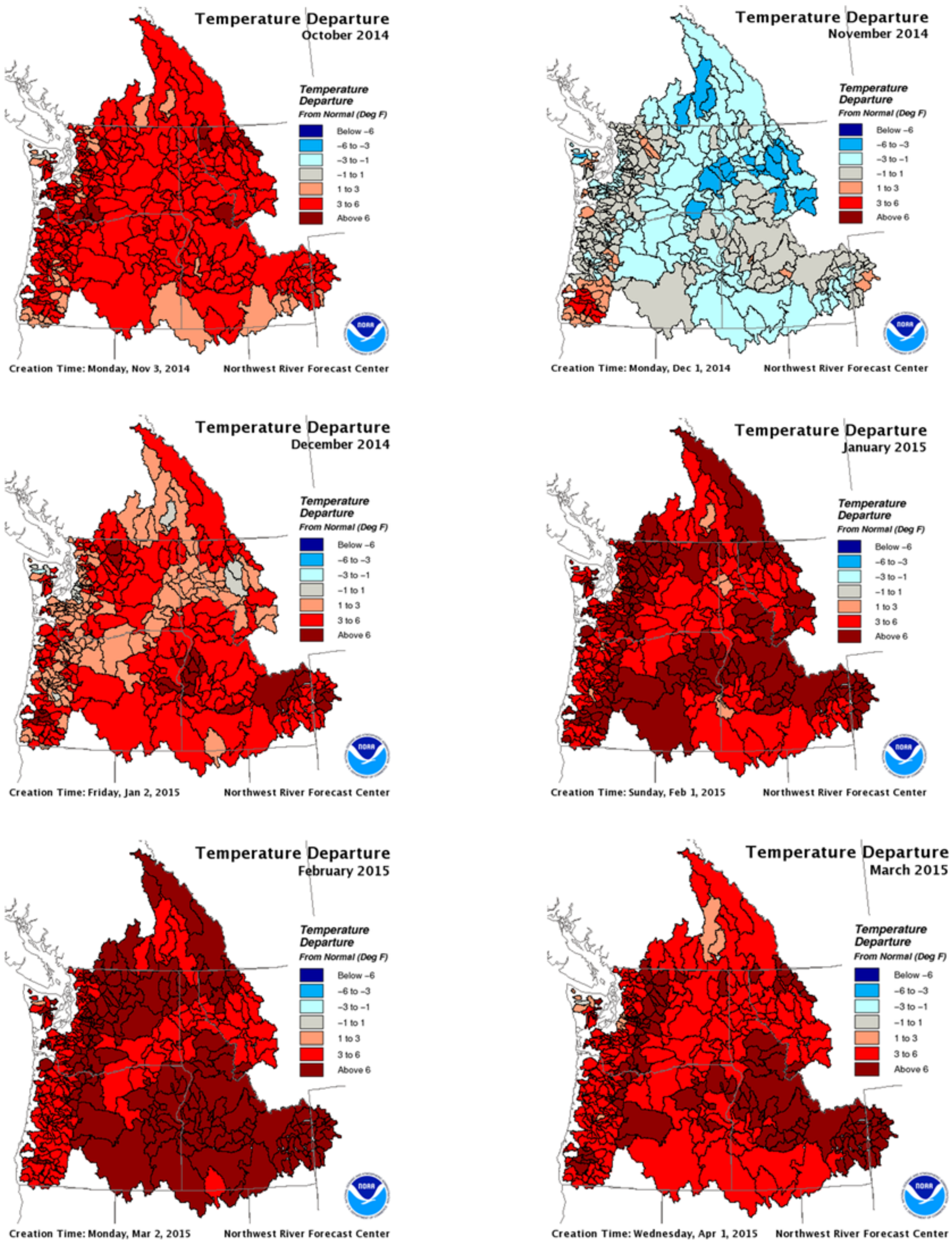


Chart 1: Pacific Northwest Monthly Temperature Departures (Continued)
April – September

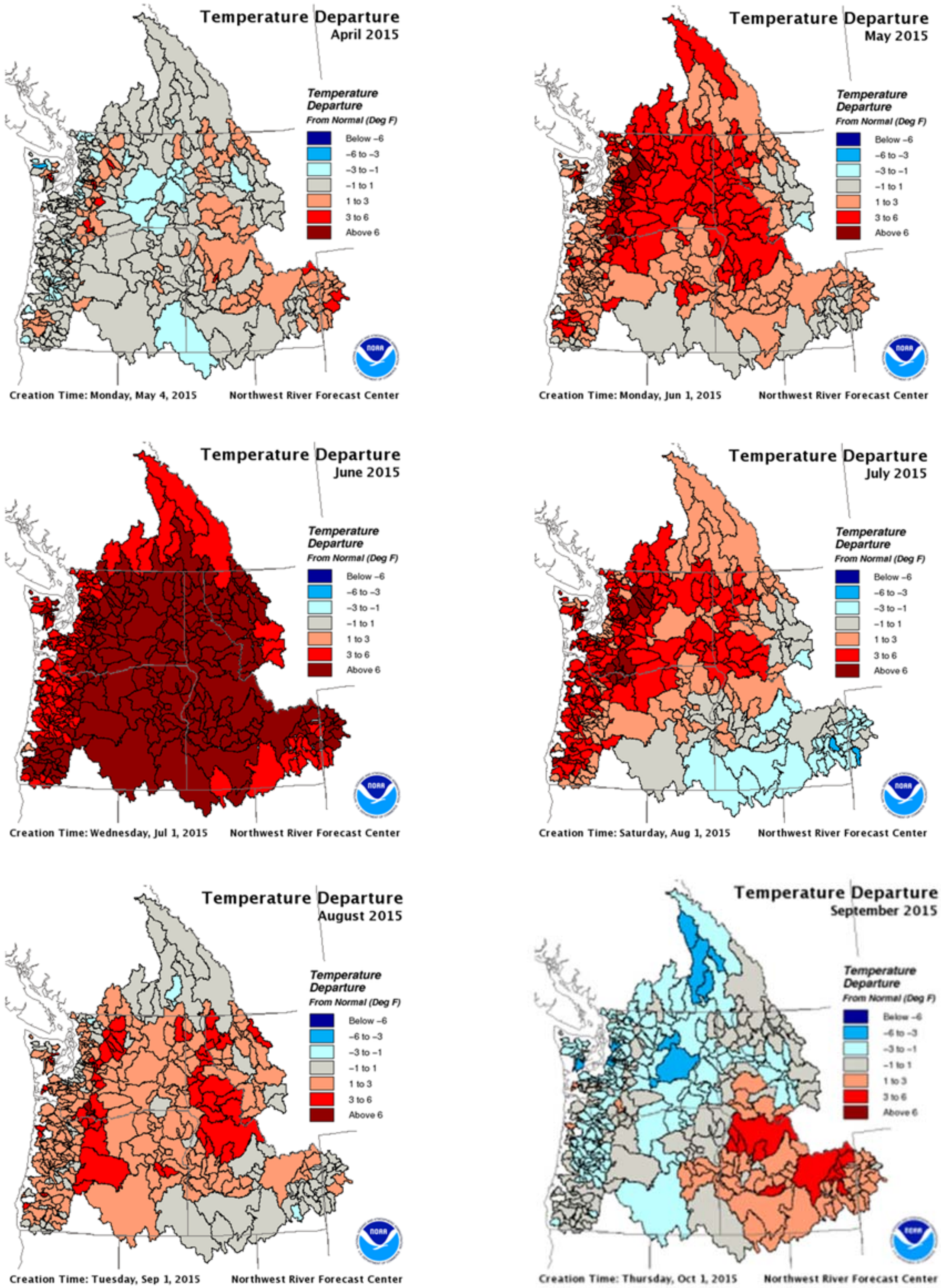


Chart 1 A: Pacific Northwest Monthly Precipitation Departures

October – March

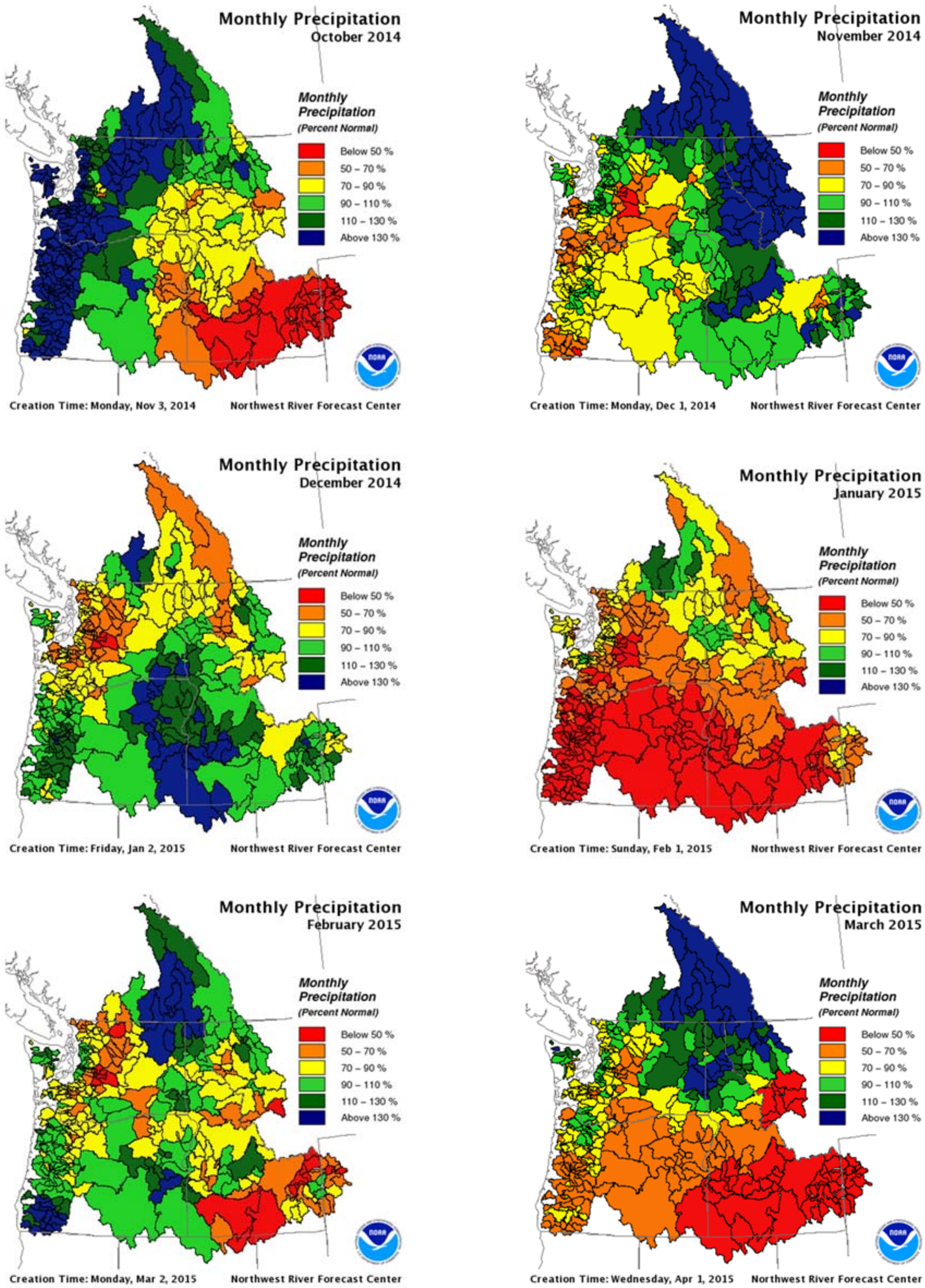
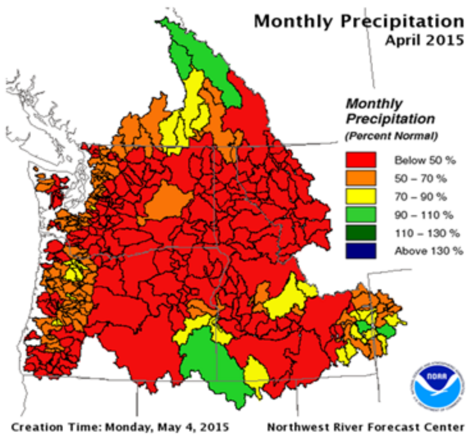
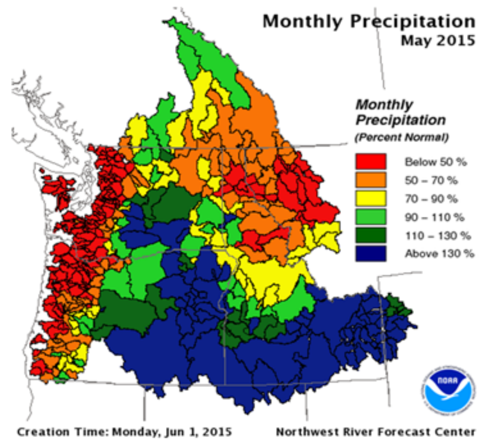
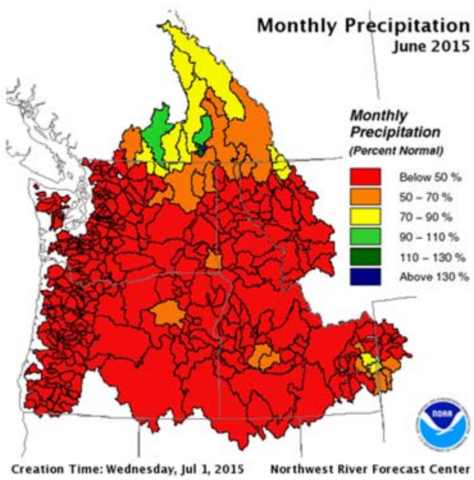
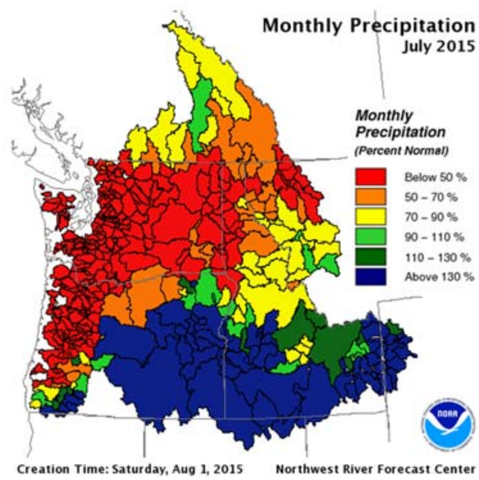


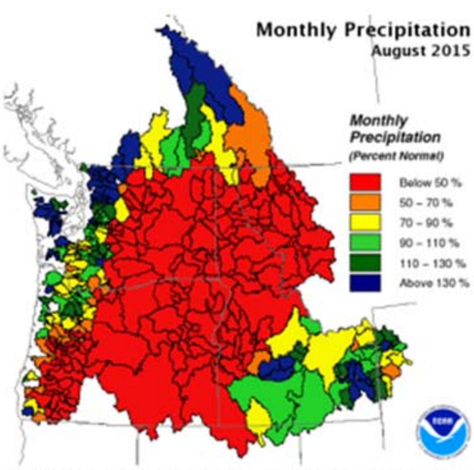
Chart 1 A: Pacific Northwest Monthly Precipitation Departures (Continued)
April – September











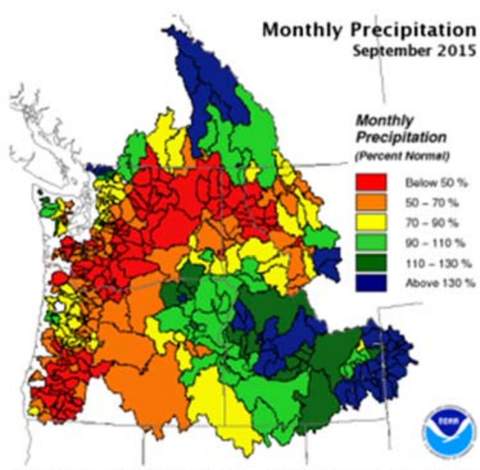


Chart 2: Seasonal Precipitation Columbia River Basin

October 2014 – September 2015

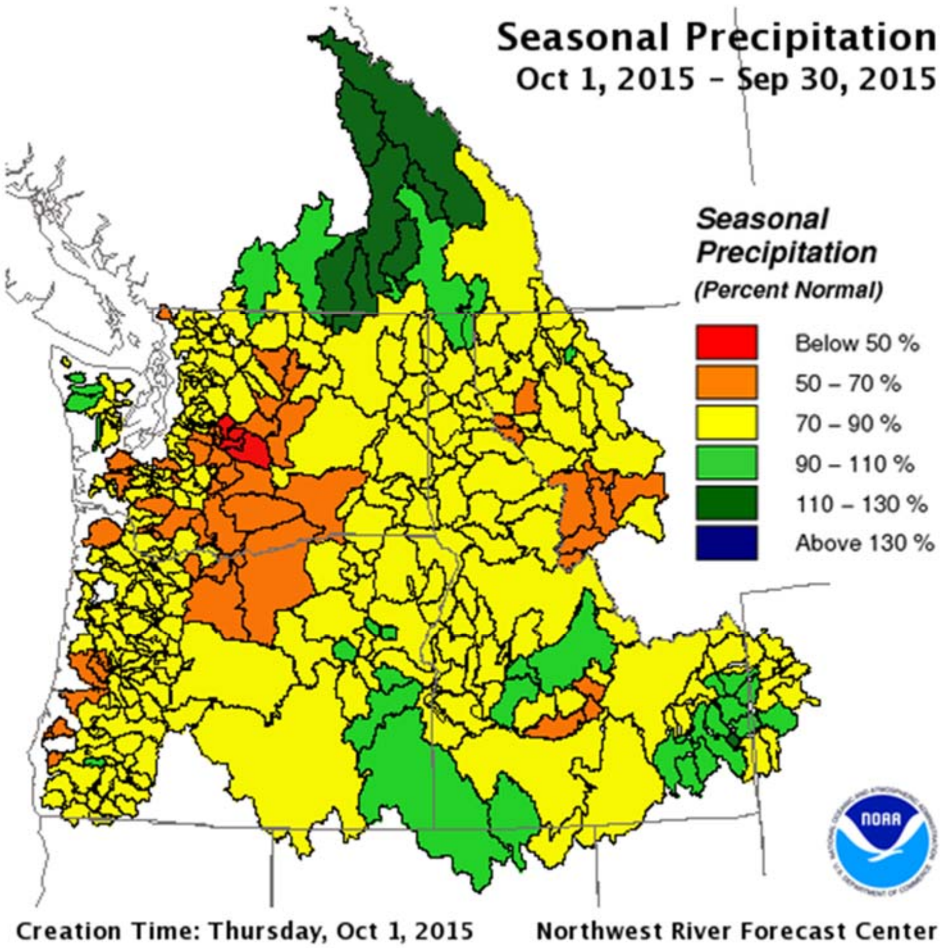


Chart 3: Columbia Basin Snowpack

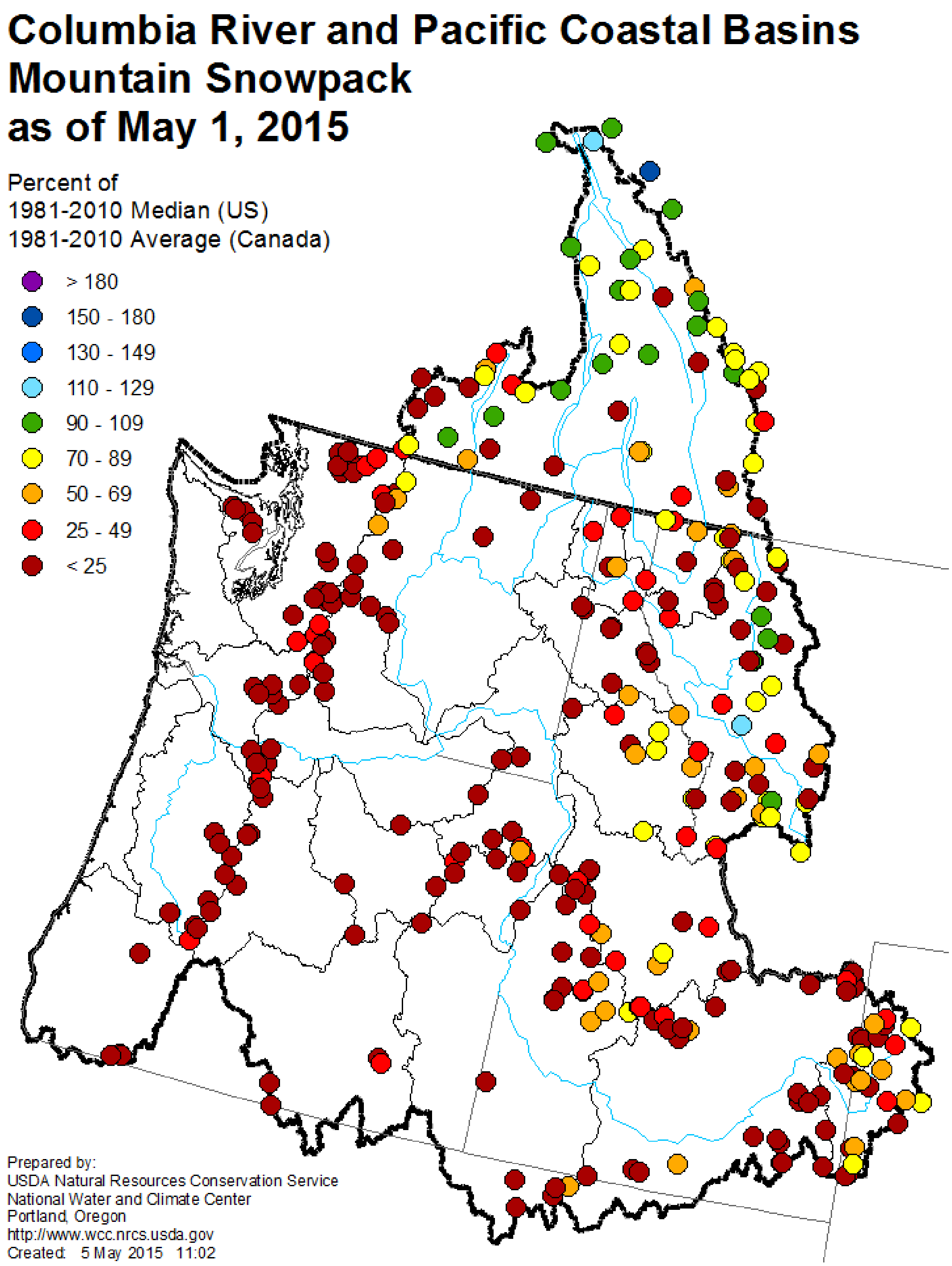


Chart 4: Accumulated Precipitation for WY 2015

At Primary Columbia River Basins

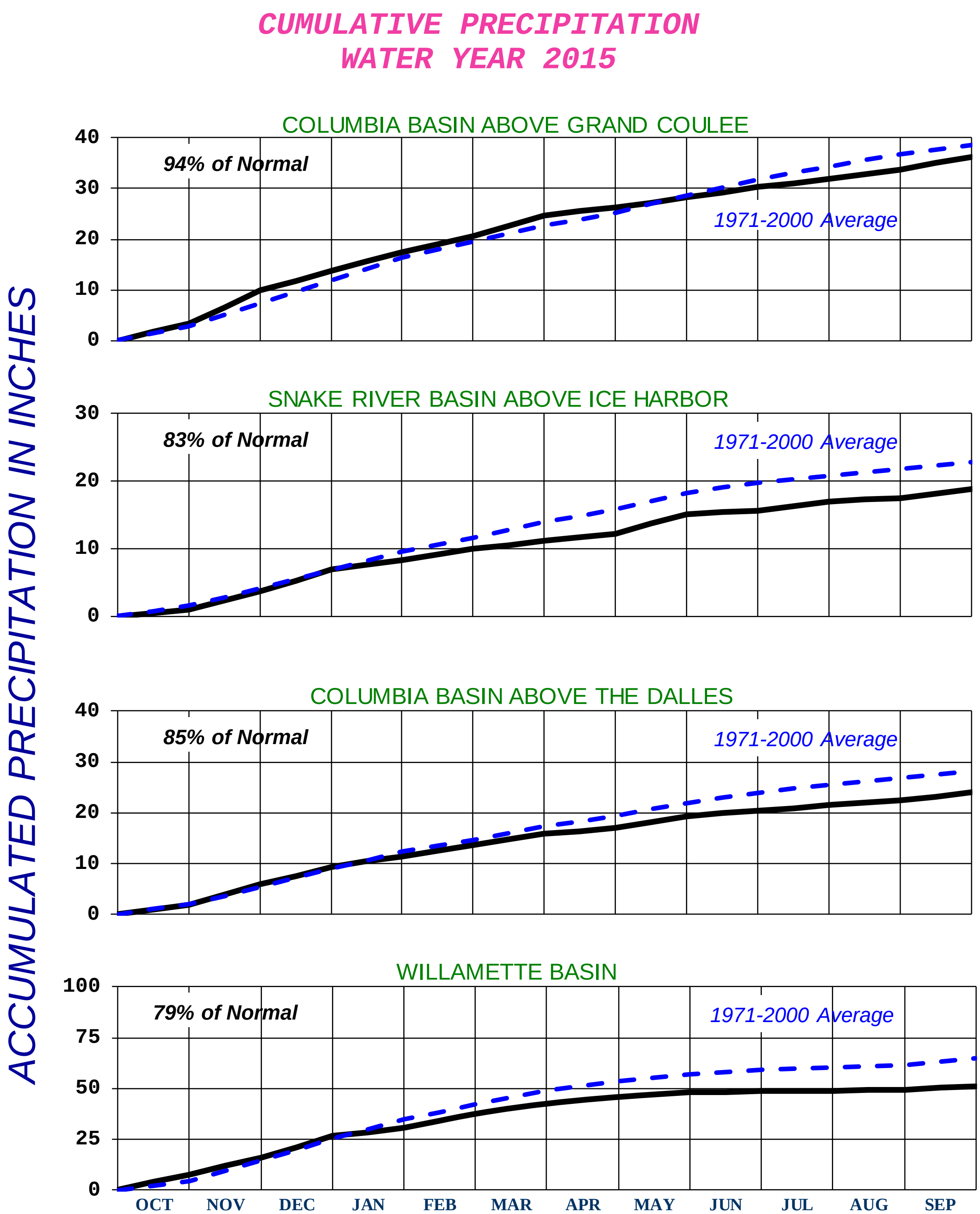
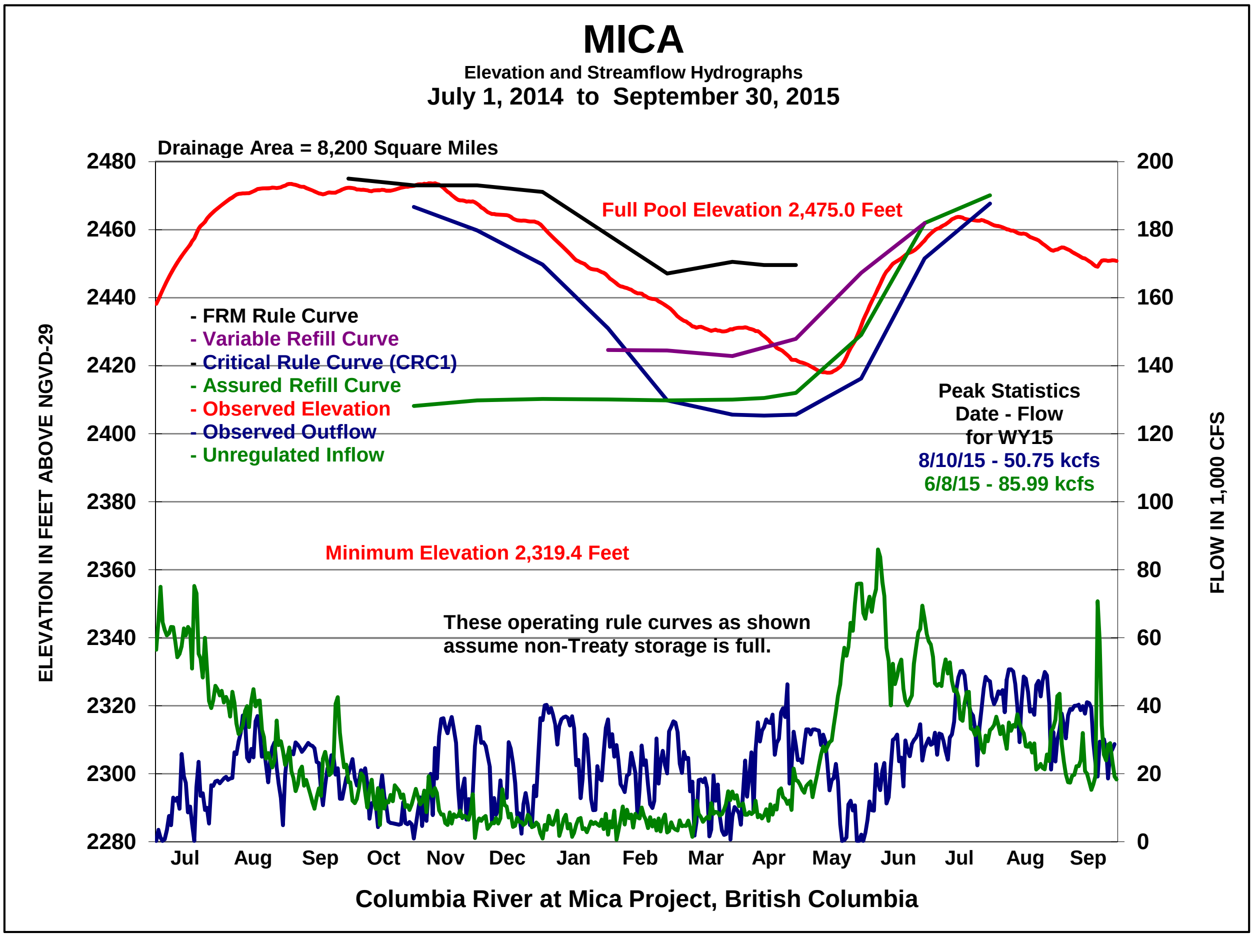


Chart 5: Regulation of Mica

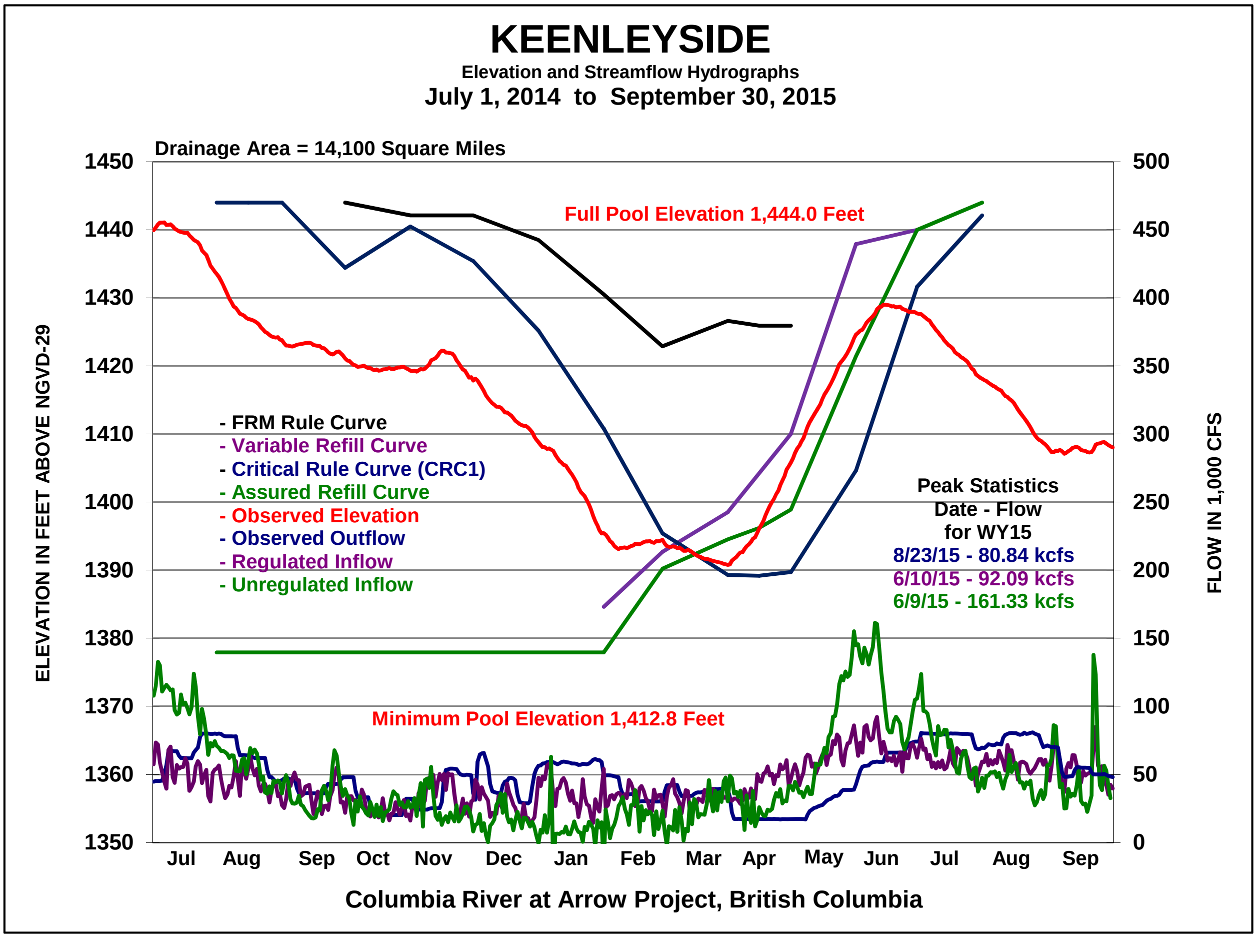
1 July 2014 – 30 September 2015



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 6: Regulation of Keenleyside

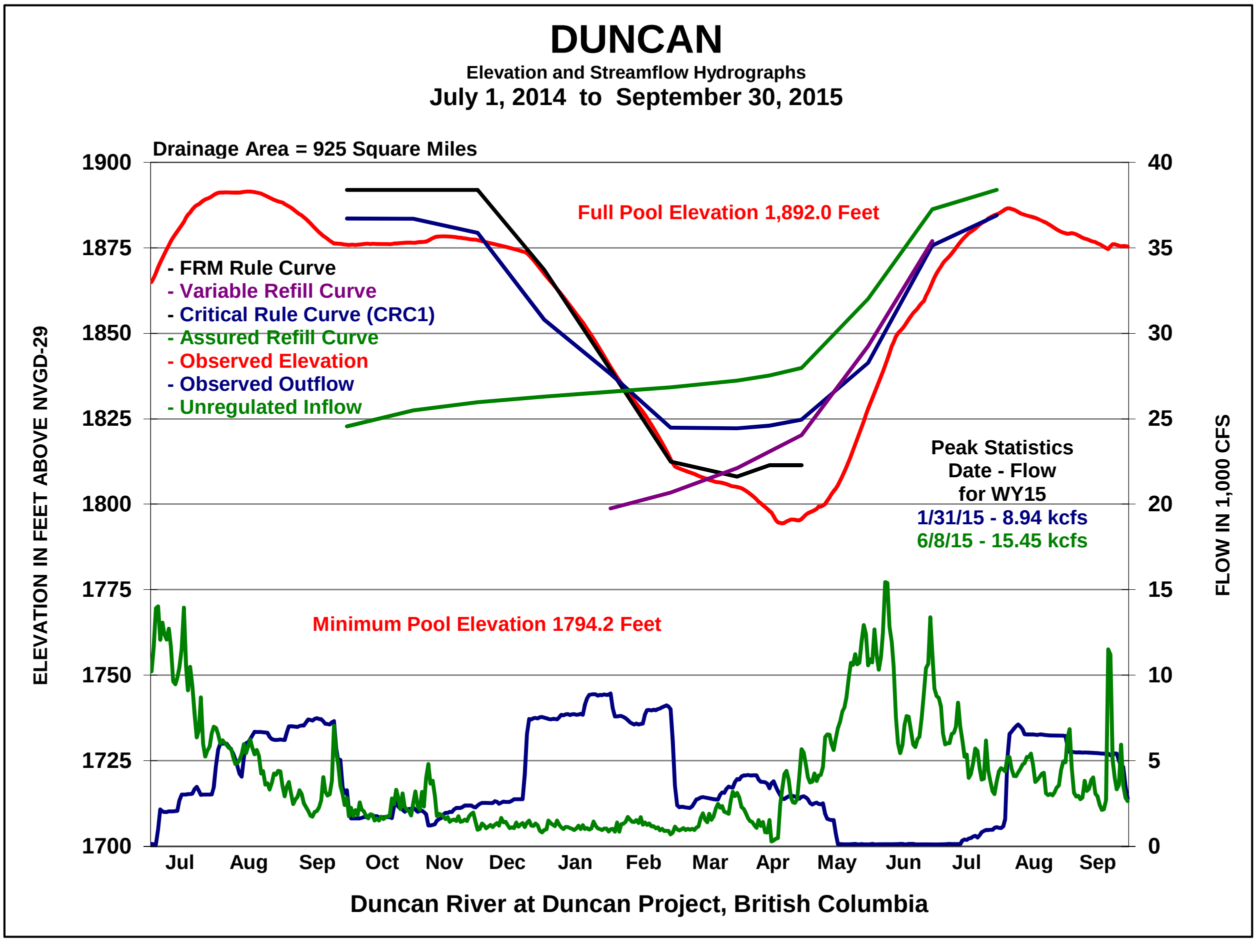
1 July 2014 – 30 September 2015



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 7: Regulation of Duncan

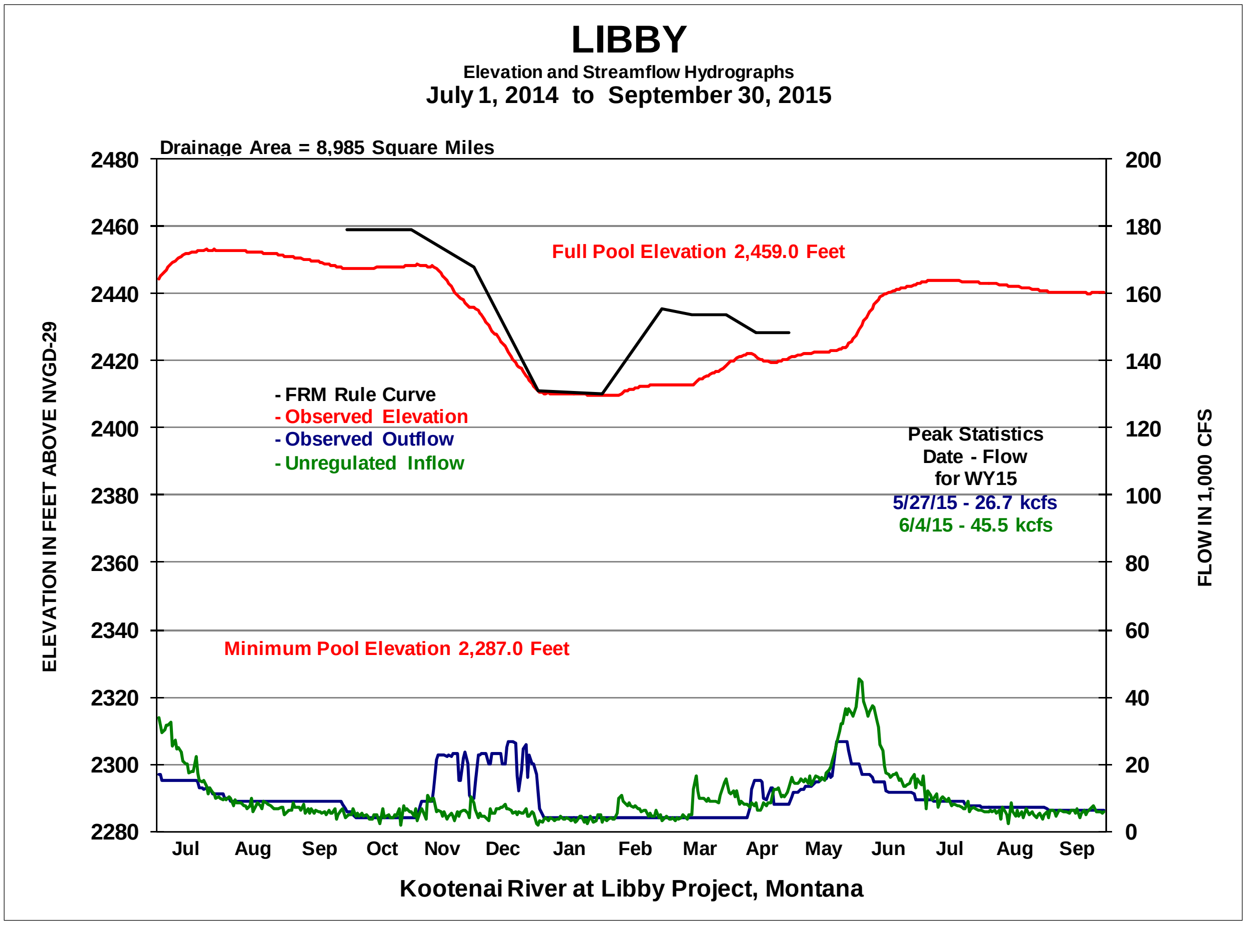
1 July 2014 – 30 September 2015



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 8: Regulation of Libby

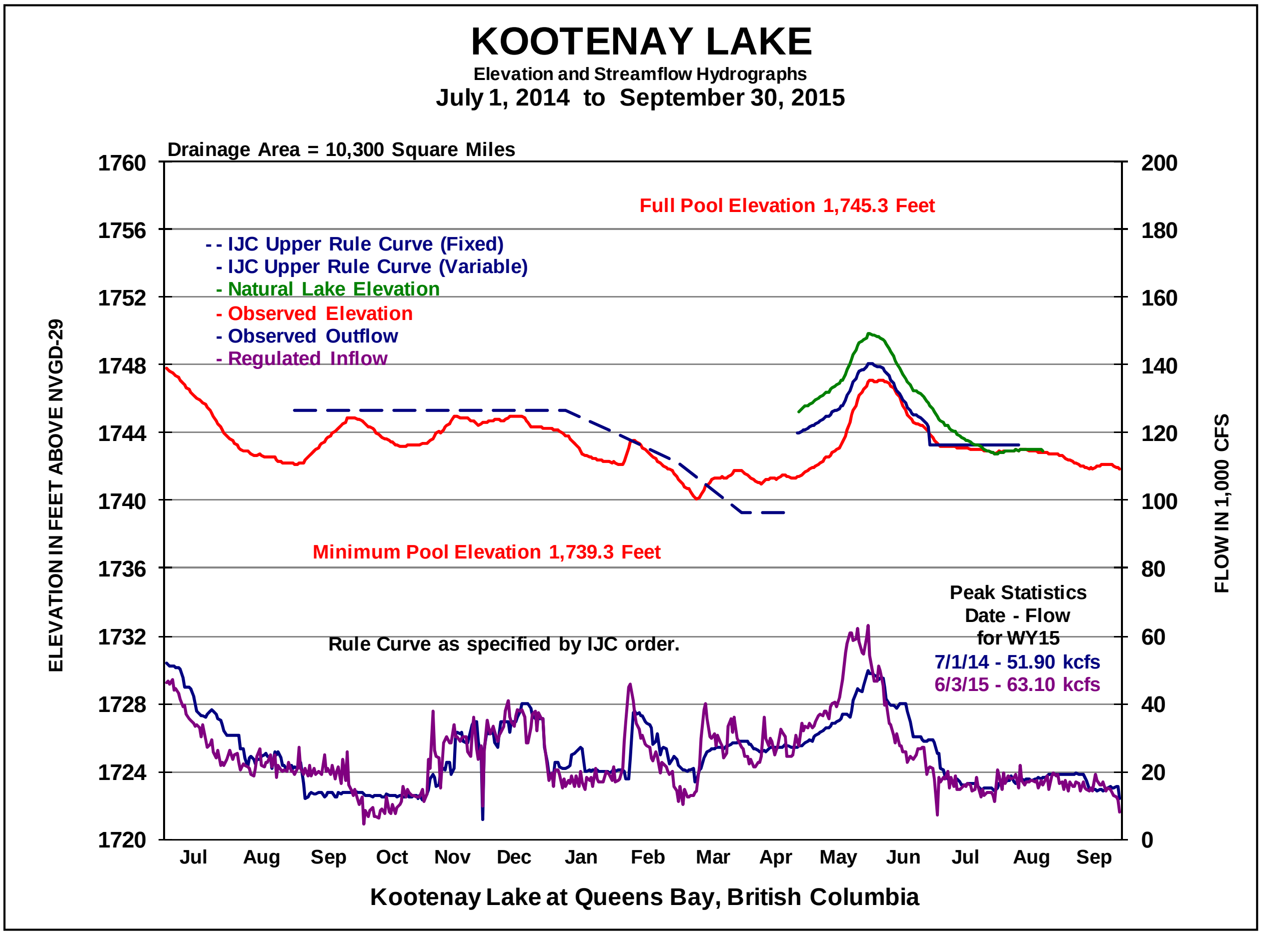
1 July 2014 – 30 September 2015



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 9: Regulation of Kootenay Lake

1 July 2014 – 30 September 2015



NGVD-29 is the National Geodetic Vertical Datum of 1929

Chart 10: Columbia River at Birchbank

1 August 2014 – 30 September 2015

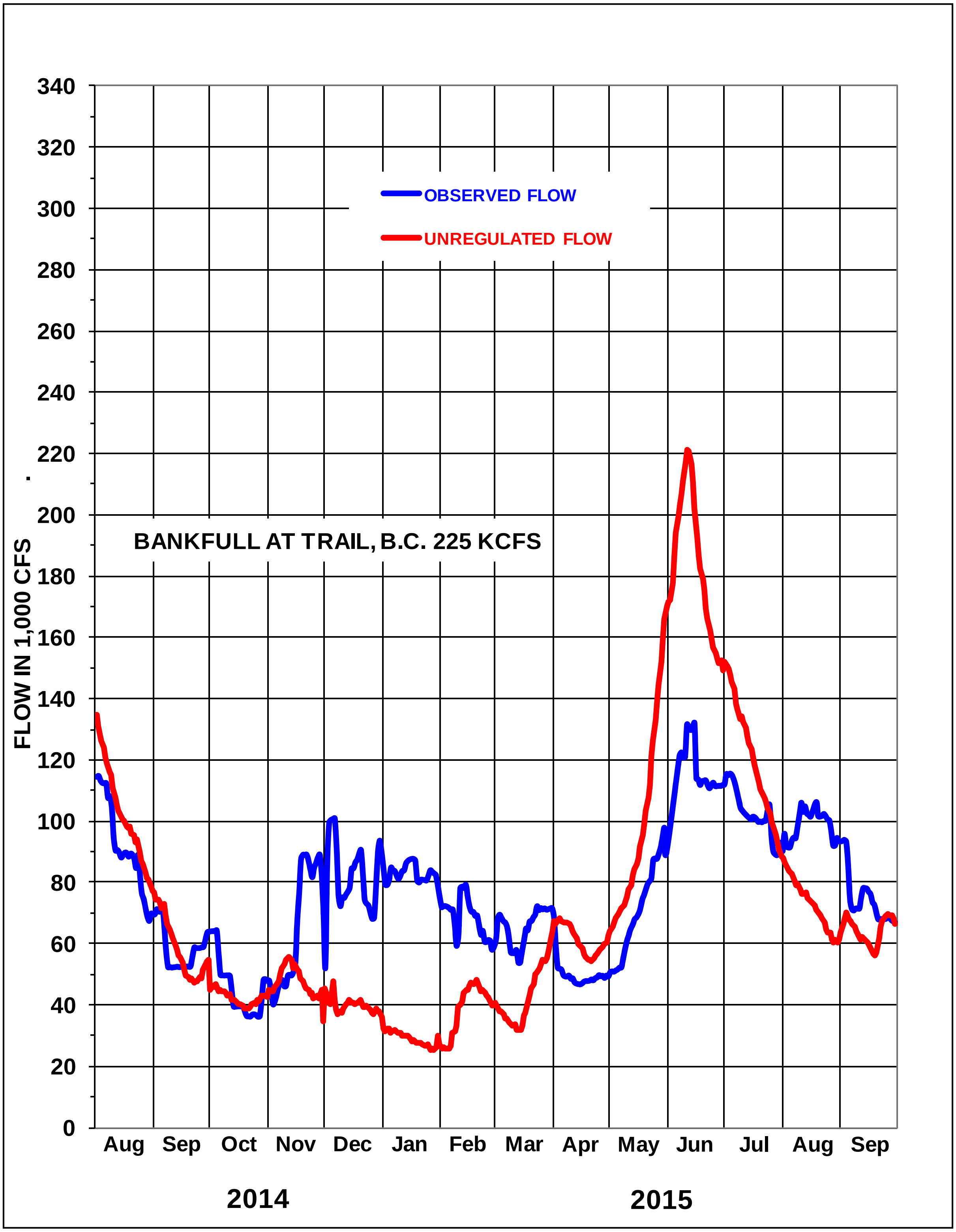
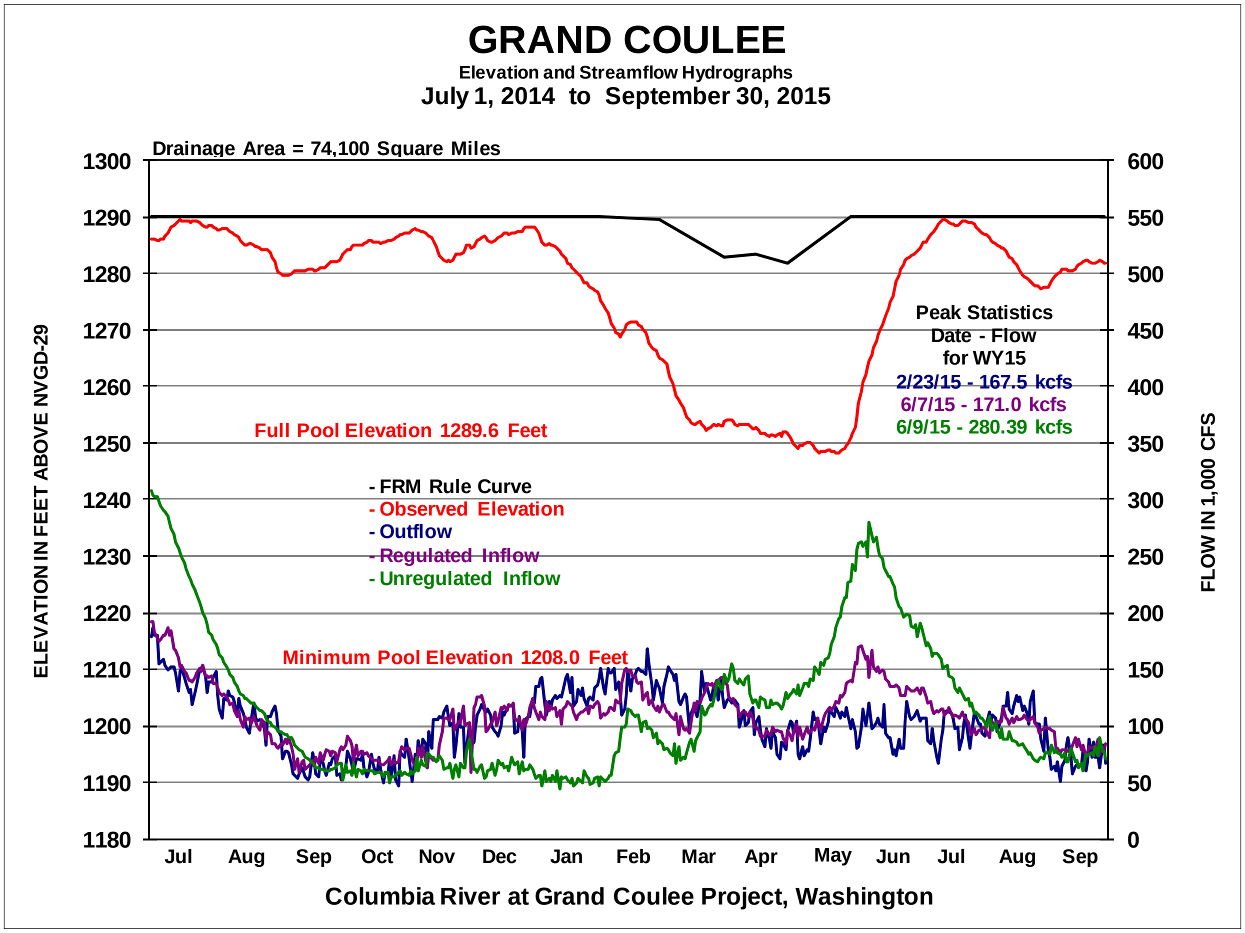


Chart 11: Regulation of Grand Coulee

1 July 2014 – 30 September 2015



NGVD-29 is the National Geodetic Vertical Datum of 1929

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

1 October 2014 – 30 September 2015

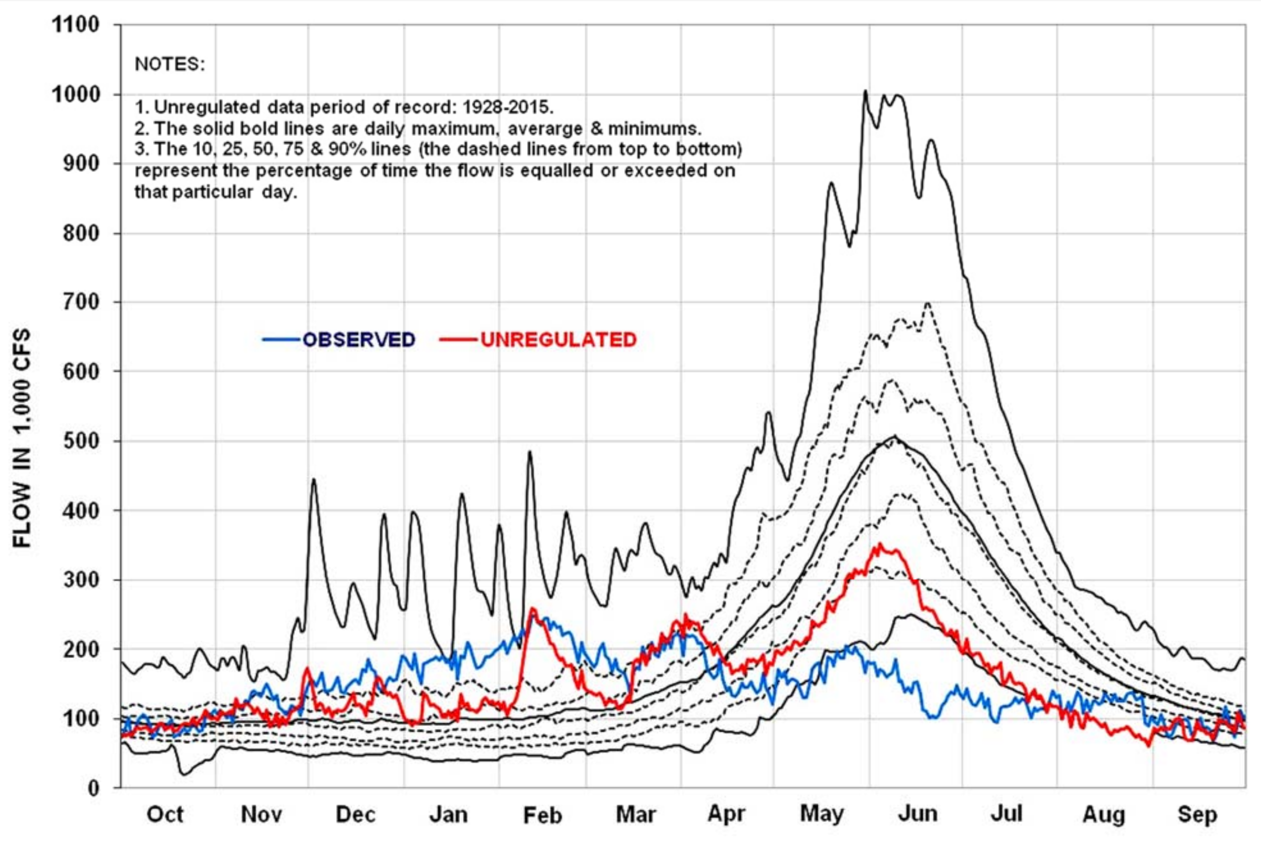


Chart 13: 2015 Columbia River at The Dalles Re-Regulation Plot

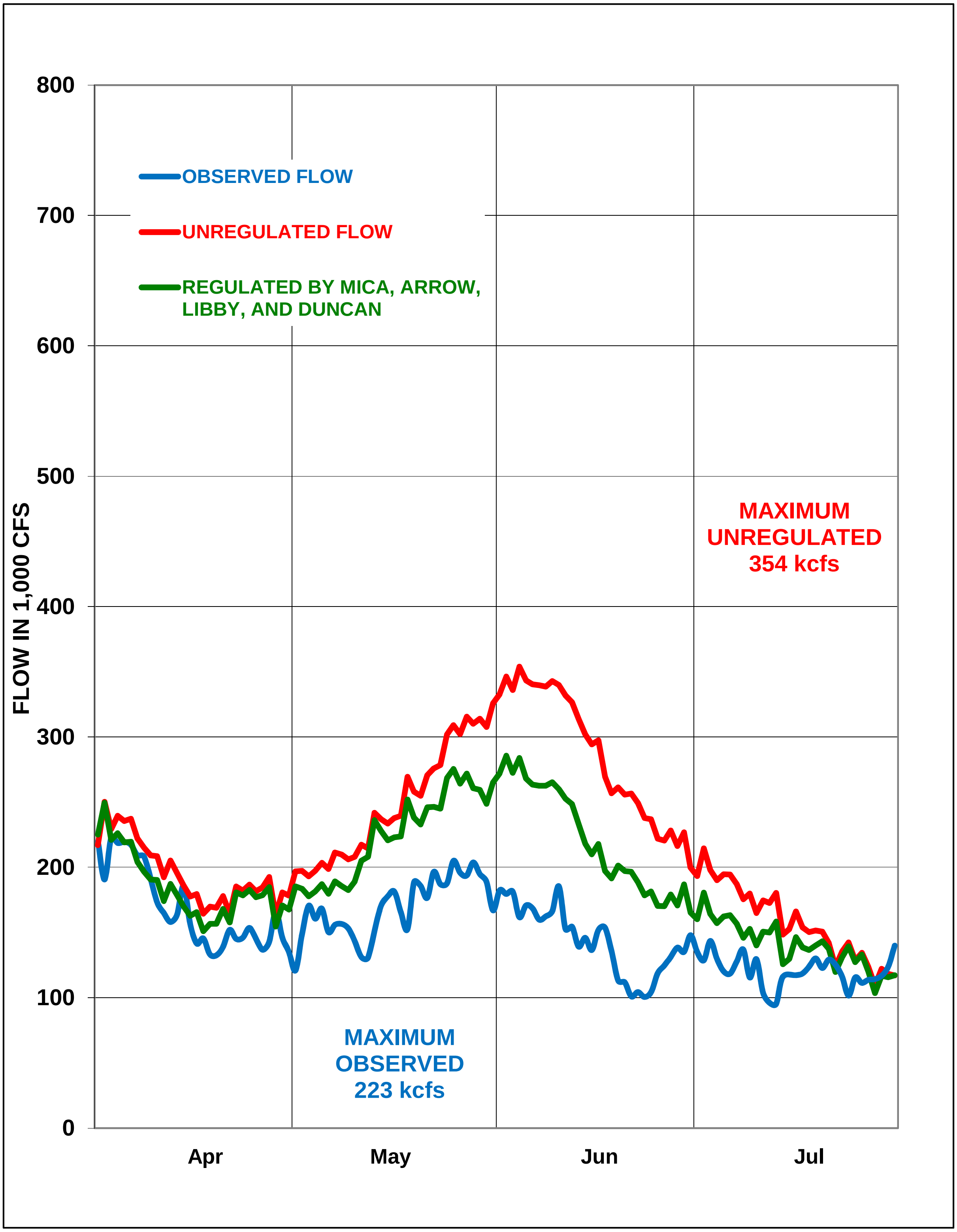
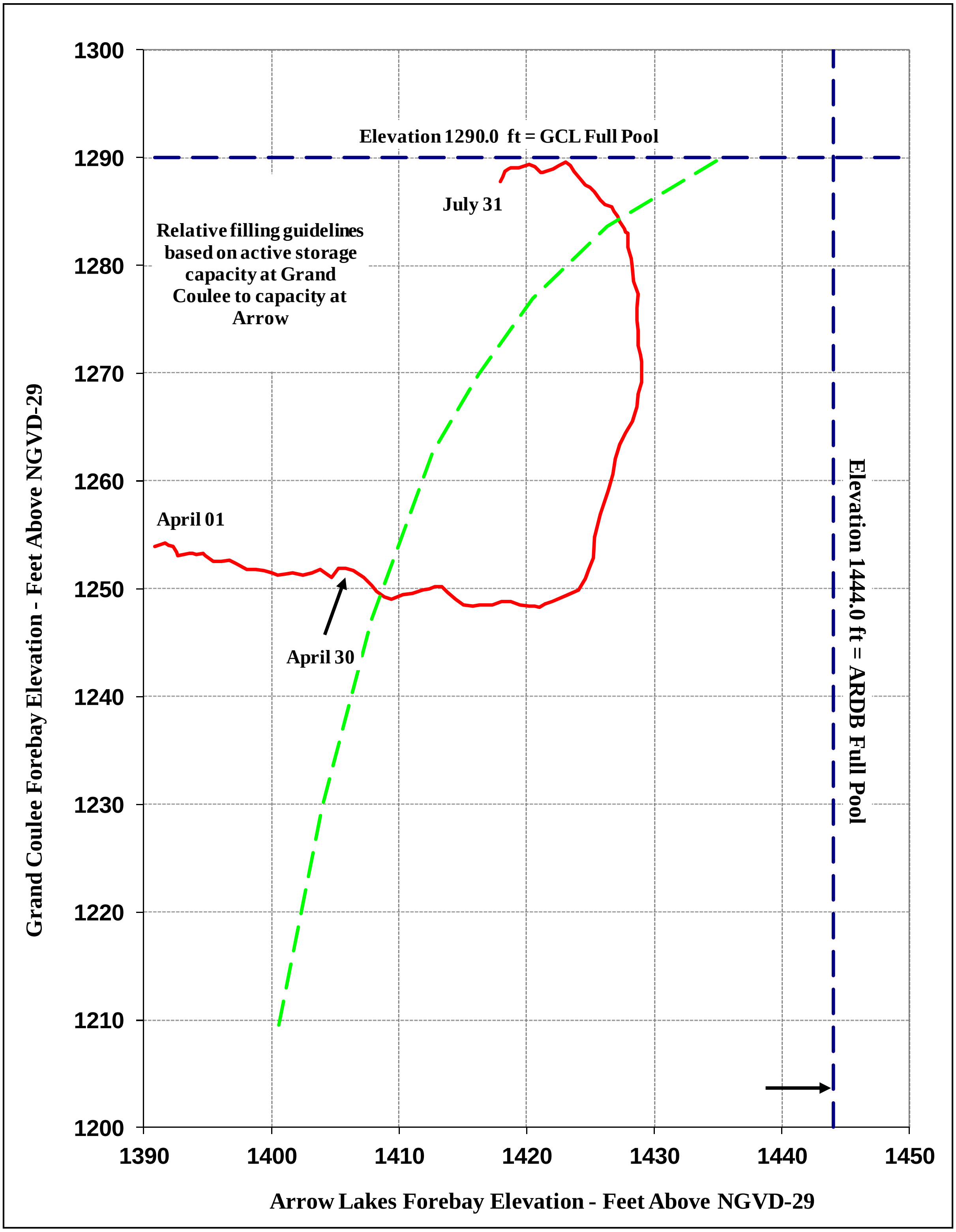


Chart 14: 2015 Relative Filling Keenleyside and Grand Coulee



NGVD-29 is the National Geodetic Vertical Datum of 1929