ANNUAL REPORT

OF THE

COLUMBIA RIVER TREATY

CANADA AND UNITED STATES ENTITIES

FOR THE PERIOD

1 AUGUST 2011 – 30 SEPTEMBER 2012

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EXECUTIVE SUMMARY

General

Water Year (WY) 2012 was another unique year in that after a relatively uneventful winter, record precipitation and cold temperatures resulted in very high runoff and a very active flood control season, especially in the Upper Columbia and Kootenai Rivers. Reservoirs in the upper part of the basin, Mica, Keenleyside, Duncan and Libby exceeded historical maximum pool elevations in operating to minimize flood damages. Notable factors contributing to this unique year were the high late spring precipitation and the very low ratio of peak discharge to runoff volume. Basin-wide precipitation in June was 164 percent of average while the April through August runoff at The Dalles was 128 percent of average, the unregulated peak flow was estimated at only 16617 m^3/s (cubic meters per second) (586.8 kcfs (thousand cubic feet per second)). For the 1 August 2011through 30 September 2012 reporting period the Canadian Treaty Projects were operated according to the 2011-2012 and the 2012-2013 Detailed Operating Plans (DOPs), the 2003 Flood Control Operating Plan (FCOP), and several supplemental operating agreements described below. The Libby project was operated consistently with the Libby Coordination Agreement (LCA) including the Libby Operating Plan, 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 Biological Opinion (BiOp) for operation and maintenance of the Federal Columbia River Power System. Modifications in actual operations were required during the May-June period due to higher than normal late season precipitation in the Upper Columbia Basin. Since 1960, 2012 ranks highest in total April-August runoff in the Upper Columbia and the Kootenai River Basins. Due to these high precipitation levels, the Canadian projects (Mica, Arrow, and Duncan reservoirs) along with the Libby project filled to above the maximum pools specified in their operating agreements and in the case of Libby Reservoir, even exceeded the maximum elevation as specified in the Columbia River Treaty. The Libby operation to exceed the Treaty maximum pool elevation of 2459.0 feet was a coordinated Treaty operation to help reduce flood damages in the Kootenai River system in both countries. In addition, British Columbia Hydro (B.C. Hydro) and Power Authority sought and received approvals from the B.C. Comptroller of Water Rights (CWR) to temporarily surcharge

Mica, Arrow, and Duncan for downstream flood control purposes, and utilized this space for flood risk management during the summer of 2012.

Entity Agreements

Agreements approved by the Entities during the period of this report include:

- Columbia River Treaty Entity Agreement on the Assured Operating Plan (AOP) and Determination of Downstream Power Benefits for Operating Year 2016-2017, signed 5 January 2012;
- Columbia River Treaty Entity Agreement on the Delegation of Certain Provisions of the Libby Coordination Agreement signed 19 April 2012;
- Columbia River Treaty Entity Agreement on the 2012 Long Term Non-Treaty Storage Agreement (Long Term NTSA), signed 10 April 2012; and
- Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Canadian Storage 1 August 2012 through 31 July 2013, signed 8 June 2012.

Columbia River Treaty Operating Committee Agreements

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

- CRTOC Agreement on Operation of Treaty Storage for Non-power Uses for 10 December 2011 through 31 July 2012 signed on 30 November 2011.

In addition to the Operating Committee agreement listed here, the Bonneville Power Administration (BPA) and B.C. Hydro and Power Authority developed the following bilateral agreements:

- Agreement for Use of NTS for the Period 2 September 2011 through 25 November 2011 (Bridge Agreement), signed 6 September 2011;
- Extension of the Short-Term Bridge Agreement between BPA and B.C. Hydro for the period 2 September 2011 through 25 November 2011, signed 21 November 2011; and
- Enabling Agreement for Arrow Outflows during 2012 High Flows, signed 27 July 2012.

System Operation

Under the 2011-2012 and 2012-2013 DOPs, Canadian storage was operated according to criteria from the 2011-2012 and 2012-2013 AOPs.

During the 2011-2012 Operating Year composite Canadian Treaty storage (Canadian Storage) was operated close to the Treaty Storage Regulation (TSR) study composite storage, plus any operations implemented under the Supplemental Operating Agreements (SOAs) or the LCA, except for some amounts of inadvertent draft or storage in all periods. Inadvertent draft or storage occurs routinely due to updated forecasts or differences between forecast and actual inflows.

Canadian Storage began the operating year 1 August 2011 slightly below the DOP levels as determined in the TSR study. Canadian Storage was drafted below TSR levels through 15 August primarily due to differences in forecast and actual inflows, but also due to the operation of the non-power agreement to smooth Arrow Treaty flows through August. Canadian Storage remained near the target TSR levels from the end of August through December.

The Canadian Entity exercised their option to provisionally draft Arrow for two cycles under the LCA this year. The first cycle drafted Arrow by 68.5 cubic hectometer (hm^3 (55.5 kaf)). This was implemented and returned (stored back) in September 2011. During December 2011, the Canadian Entity exercised the second option to provisionally draft Arrow. This 137 hm^3 (111 kaf) provisional draft was returned in early January and the remainder by late March.

For January until the end of June 2012, Canadian Storage remained above the TSR-specified levels. This was due to operation under the Non-Power Uses Agreement that was implemented to achieve mutual fish benefits for the U.S. and Canada. Under provisions of this agreement, the U.S. Entity stored 1233 hm^3 (1 Maf) of flow augmentation water. At the time this water was stored, the water supply forecast was less than average (at 91.4 Maf or 112.7 km^3). This operation helped to modify and manage flows downstream of Hugh Keenleyside Dam for Canadian whitefish operation in January through March, and for Canadian trout spawning protection in April through June 2012.

The flow augmentation water was subsequently released during July 2012 to avoid exceeding the flood control maximum levels in May through June, to meet U.S. salmon flow objectives in

July. The spring water supply forecasts at The Dalles increased as the water year developed, from 121.9 km^3 (98.8 Maf) (January-July) in March to 158.4 km^3 (128.4 Maf) in July.

During the spring freshet, B.C. Hydro sought and received approvals from the B.C. CWR to surcharge by up to 3 feet at Mica, 3 feet at Arrow, and 2 feet at Duncan reservoirs for downstream flood control purposes. Additionally, B.C. Hydro and BPA exercised storage operation under the Long Term Non-Treaty Storage agreement from May through mid-July by utilizing the maximum available Non-Treaty Storage (NTS). This Non-Treaty Storage was made available due to earlier releases under the Bridge Agreement. A total of approximately 2.3 Maf (2.83 km^3) was released by early March. Refer to Section III Long Term Non-Treaty Storage for more information on Non-Treaty operations. Even with this operation, the Columbia River flows at Birchbank (downstream of the Kootenai and Columbia confluence) peaked at 6090 m^3/s (215 kcfs) on 21 July 2012, the highest flow recorded since the Treaty dams began operation. Flows at Birchbank returned to non-flood levels when they receded to 4670 m^3/s (165 kcfs) on 1 August 2012.

For the August through September 2012 period, Canadian Storage was slightly below TSR levels due to differences in forecast and actual inflows.

Canadian Entitlement

For the period 1 August 2011 through 31 July 2012, the Canadian Entitlement amount, before deducting transmission losses, was 525.9 Average Megawatts (aMW) of energy, scheduled at rates up to 1314 Megawatt (MW). From 1 August 2012 through 30 September 2012, the amount, before deducting transmission losses, was 504.5 aMW of energy, scheduled at rates up to 1321 MW. The Canadian Entitlement obligation was determined by the 2011-2012 and 2012-2013 AOP and Determination of Downstream Power Benefits (DDPBs).

During the course of the 2011-2012 Operating Year, there were four curtailment events for Canadian Entitlement deliveries within a span of two months, primarily due to a combination of planned maintenance and unexpected weather/load-resource conditions that included system constraints from wind power production. These included a 557 megawatt hour (MWh) reduction on 1 March 2012, and a 22 MWh reduction the following day. Subsequent reductions included a 3 MWh reduction on 14 March 2012 and a 43 MWh reduction on 24 April 2012. A 43 MWh

curtailment was also realized on 9 September 2012, due to forest fires near transmission lines. All of the curtailed power was delivered later within the same month of curtailment, as per agreements between the Entities. The U.S. Entity also invited a BPA transmission system expert to explain to the CRTOC the operating circumstances and grid congestion events that contributed to these unplanned, pro-rata cuts to firm transmission schedules in the Northwest, which included reductions to the Canadian Entitlements deliveries. This occurred at the 23 May 2012 meeting.

Treaty Project Operation

At the beginning of the 2011-2012 Operating Year, 1 August 2011, actual Canadian storage was at 18.9 km^3 (15.3 Maf) or 99.2 percent full. Canadian storage ended the operating year on 31 July 2012, at 19.1km^3 (15.5 Maf) or 100 percent full.

MICA (Kinbasket Reservoir)

The Kinbasket Reservoir reached its 2011 maximum elevation of 754.17 m (2474.3 ft) on 3 October 2011 due to a number of rainfall events in late September through early October contributing to high basin inflows. The reservoir was drawn down during the fall and winter to meet electrical demands and to prepare for above normal spring runoff and extensive planned generating unit outages in the spring/summer 2012. The project ran harder than normal due to the flexibility of moving additional water from Mica and Arrow in the fall/winter under the Bridge Agreement between BPA and B.C. Hydro. Kinbasket Reservoir reached a minimum level this year of 722.0 m (2368.7 ft) on 21 April 2012; about 3 m (10 ft) lower than the 2011 minimum level. Mica generation was limited to 2 units during an extended outage from March through August 2012. Mica power-plant output was gradually reduced in May but remained above normal in the latter half of May due to unusually cool weather and higher load demands. From mid-June to mid-July, generation was reduced to near minimum.

The basin runoff forecast increased from month to month starting from near normal in January to 120 percent of normal in the 1 June forecast. The situation was compounded by extraordinary amounts of rain throughout June and into July throughout the province. The actual February-July inflows at Mica were about 135 percent of normal, the highest recorded runoff in the 40-year period. In July, due to high freshet flows, B.C. Hydro received permission from the B.C. CWR, to surcharge

all of its major reservoirs in the Columbia/Kootenai system (Kinbasket, Revelstoke, Arrow, and Duncan). For Kinbasket Reservoir, the project was permitted to surcharge the first 0.3 m (1 ft) for power purposes and an additional 0.6 m (2 ft) for downstream flood control.

To manage the refill of Kinbasket Reservoir, Mica releases were increased through a combination of spill and generation on 15 July. Generation was increased to maximum possible with 2 unit operation and the project spilled until the end of August when the power-plant was returned to service. The Kinbasket Reservoir reached a maximum level of 754.7 m (2476.0 ft), or 0.3 m (1.0 ft) above full pool on 28 August 2012. The 2012 spill at Mica was the first spill at the facility since 1997.

KEENLEYSIDE (Arrow Lakes Reservoir)

The Arrow Lakes Reservoir reached a maximum level of 439.6 m (1442.1 ft), or 0.6 m (1.9 ft) below full pool on 28 July 2011, just prior to the start of the 2011-2012 Operating Year. Due to above normal runoff in the Columbia system, Canadian treaty storage did not operate in proportional draft mode at any time during the 2011-2012 Operating Year. In anticipation of extended outages at Mica and high freshet runoff, B.C. Hydro and BPA developed a Bridge agreement to allow additional releases from Mica and Arrow reservoirs using NTS space prior to the spring freshet. The minimum level for Arrow Lakes Reservoir during 2012 was 427.5 m (1402.6 ft) on 1 April, 2012. This was 3m (10 ft) lower than the previous year's minimum level.

The Arrow local runoff forecast also increased from month to month starting from slightly below normal in January to 112 percent of normal in the 1 June forecast. The Canadian Lower Columbia region received exceptionally high amounts of rain throughout June, recording 2 to 3 times the normal amount of rain at Castlegar, B.C. Actual local February to July inflows were about 126 percent of normal and were the 3rd highest recorded in the 42-year period. Due to high freshet flows, B.C. Hydro received permission from the B.C. CWR to surcharge Arrow Reservoir by up to 0.9 m (3 ft) for downstream flood control.

As basin inflows increased during May through July, the reservoir filled rapidly exceeding its normal full pool on 4 July 2012 and reaching a maximum level of 440.5 m (1445.3 ft), or 0.4 m (1.3 ft) above full pool on 22 July 2012, this was the highest Arrow Reservoir level since 1990. Downstream of Arrow, Columbia River flows at Birchbank exceeded 4670 m^3/s (165 kcfs), the threshold flow for minor flooding impacts, on 24 June 2012. Under the Long Term NTSA, 2.8 Maf of empty reservoir was completely refilled during June and July 2012 to assist

downstream flood management. During this period of unusual runoff conditions on the Columbia system, these agreements provided significant power and flood control benefits for communities in the region. Flows in the Columbia River at Birchbank peaked at 6090 m^3/s (215 kcfs) on 21 July 2012. While this was the highest recorded flow since the four Treaty dams began operation, efforts to maintain flows below the more damaging threshold of 6370 m3/s (225 kcfs) were successful. Columbia River flows at Birchbank returned to non-flood levels (below 4672 m^3/s or 165 kcfs on 1 August 2012. The Arrow Reservoir level returned to normal full pool, 440.13 m (1444 ft) on 30 July 2012 and then continued to draft across the remaining summer months, reaching, 433.9 m (1423.7 ft) on 30 September 2012.

DUNCAN (Duncan Reservoir)

Duncan Reservoir filled to 576.71 m (1892.2 ft) or 0.03 m (0.2 ft) above full on 1 August 2011. From September 2011 through April 2012, Duncan Reservoir was operated to supplement inflow into Kootenay Lake to provide spawning and incubation flows for fish and to meet Treaty flood control requirements. Duncan Reservoir was drafted to 547.0 m (1794.7 ft) on 14 April 2012 or near its licensed minimum level. The reservoir normally reaches its annual minimum level between mid-April and early May. The reservoir discharge was reduced to a minimum of 3 m^3/s (0.1 kcfs) beginning 7 June 2012 to initiate reservoir refill and to reduce flood levels on Kootenay Lake. In response to significant rainstorms in June and July, Duncan Reservoir inflows increased dramatically, and B.C. Hydro received permission from the B.C. CWR to store 0.6 m (2 ft) above the normal full pool level. Releases from Duncan Reservoir were held at minimum until early July to help manage the high levels of Kootenay Lake. After the Kootenay Lake level began to recede; Duncan Reservoir discharges were increased to manage (slow) the rate of refill for Duncan Reservoir. By 20 July 2012, Duncan Reservoir reached full pool, and then surcharged by 0.3 m (1 ft) over its full pool level to 577.0 m (1893.0 ft) on 23 July, reaching its highest level recorded since the dam began operation in 1967.

With Duncan Reservoir passing inflow and high concurrent discharges in the unregulated Lardeau River, the flows in the Duncan River downstream of the Lardeau (DRL) peaked at 575 m^3/s (20.3 kcfs) on 21 July 2012. While this peak flow was well above the normal annual peak flow, the reservoir filling and surcharge operation did reduce discharges and flood damages immediately downstream, with little impact around the Duncan Reservoir shoreline. As inflows subsided, Duncan Reservoir discharges were adjusted across August and early September to

target a reservoir elevation of ~575.2 +/- 0.3 m (~1,887 +/- 1 ft) on Labor Day (3 September). For the balance of September, project flows were increased to draft the reservoir to reach an elevation of 571.5 m (1875.0 ft) on 30 September 2012.

LIBBY (Koocanusa Reservoir)

The Koocanusa Reservoir filled to a maximum elevation of 747.8 m (2453.4 ft) on 4 August 2011, 1.7 m (5.6 ft) from full pool and drafted to elevation 746.1 m (2447.7 ft) by 31 August 2011, and to elevation 745.8 m (2446.8 ft) by 30 September 2011. Drafting continued through the fall and winter period. By 31 December 2011, the reservoir was at elevation 735.3 m (2412.4 ft) and operated during the winter to the Variable Discharge Flood Control (VARQ) storage reservation diagram. The late winter and spring period was characterized by above average snow build-up followed by heavy rains in June and a rising water supply forecast. Lake Koocanusa was drafted to elevation 728.5 m (2390.2 ft) at the end of April. The reservoir drafted to its lowest elevation of 725.7 m (2380.9 ft) on 23 April 2012. Outflow was adjusted pursuant to VARQ rules as well as system flood risk management refill guidance. In 2012 Libby Dam provided 1.46 km^3 (1.18 Maf) of storage for sturgeon releases. An exceptionally wet June required a balancing act between controlling the forebay levels while minimizing impacts downstream. For the first time ever, the Treaty Operating Committee coordinated a surcharge of Lake Koocanusa for the purpose of reducing downstream flood damage in both countries. The reservoir filled to a project record elevation of 749.8 m (2459.96 ft) on 14 July 2012 and then again on 16 July 2012, 0.3 m (0.88 ft) above full pool and drafted to elevation 747.31 m (2451.7 ft) by 31 August 2012 and to elevation 746.3 m (2448.34 ft) by 30 September 2012. The final April through August inflow volume to the project was 9.2 Maf or 147 percent of normal (1971 – 2000, 30 year normal).

Columbia Basin Map

2012 Report of the Columbia River Treaty Entities
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Acronyms and Abbreviations

AER.....Actual Energy Regulation

aMW…….. .....Average Megawatts

AOP…….....Assured Operating Plan

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

BiOp .....Biological Opinion

BG ….....Brigadier General

BPA.....Bonneville Power Administration

CEEA .....Canadian Entitlement Exchange Agreement

CEPA .....Canadian Entitlement Purchase Agreement

cfs.....Cubic feet per second

COL……...Colonel

CRC.....Critical Rule Curve

CRT.....Columbia River Treaty

CRITFC.....Columbia River Inter-Tribal Fish Commission

CRTHC .....Columbia River Treaty Hydrometeorological Committee

CRTOC .....Columbia River Treaty Operating Committee

CSPE.....Columbia Storage Power Exchange

CWR .....Comptroller of Water Rights

DDPB.....Determination of Downstream Power Benefits

DoD……Department of Defense

DOP.....Detailed Operating Plan

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

ESP.....Ensemble Streamflow Prediction

FCOP.....Flood Control Operating Plans

ft .....feet

FTP.....File Transfer Protocol

hm^3 .....Cubic hectometers

in .....inch

ICF .....Initial Controlled Flow

IJC .....International Joint Commission

kaf .....Thousand acre feet

kcfs .....Thousand cubic feet per second

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

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

LCA.....Libby Coordination Agreement

LOP .....Libby Operating Plan

m .....Meter

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

Maf.....Million acre-feet

MW .....Megawatt

MWH .....Megawatt hour

NMFS.....National Marine Fisheries Service

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

NTS .....Non-Treaty Storage

NTSA .....Non-Treaty Storage Agreement

NWRFC .....Northwest River Forecast Center

ORC .....Operating Rule Curve

ORCLL .....Operating Rule Curve Lower Limits

OY.....Operating Year

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

RMJOC .....River Management Joint Operating Committee

SFTP .....Secure File Transfer Protocol

SOAs.....Supplemental Operating Agreements

SOR.....System Operational Requests

TMT .....Technical Management Team

TSR .....Treaty Storage Regulation

U.S. .....United States

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

USFWS .....U.S. Fish and Wildlife Service

VARQ .....Variable discharge flood control

VRC .....Variable refill curves

VRCLL .....Variable Refill Curves Lower Limits

WCDS .....Water Control Data System

WSF .....Water Supply Forecast

WUP.....Water Use Plan

WY .....Water Year

I – INTRODUCTION

This annual Columbia River Treaty Entity Report is for the Water Year (WY) 2012, 1 October 2011 through 30 September 2012, with additional information on the operation of Mica, Arrow, Duncan, and Libby Reservoirs, as needed to also cover the reservoir system operating year, 1 August 2011 through 31 July 2012. Also described are the power and flood control effects downstream in Canada and the U.S. This report is the 46th of a series of annual reports covering the period since the ratification of the Columbia River Treaty (Treaty, CRT) in September 1964.

Duncan, Arrow, and Mica Reservoirs in Canada were constructed as required under the CRT, and Libby Reservoir in the U.S. was constructed as provided for by the CRT. Treaty storage in Canada (Canadian storage) is operated for the purposes of flood control 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 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 United States 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 Engineer of the Northwestern Division, U.S. Army Corps of Engineers (USACE).

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 Mica, 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 control 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 control 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.

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 (and otherwise indefinitely), 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.

10. In the Canadian Entitlement and Purchase Agreement (CEPA) of 13 August 1964, Canada sold its entitlement to downstream power benefits (Canadian Entitlement) to the Columbia Storage Purchase Exchange (CSPE - a consortium of U.S. utilities) for 30 years beginning at Duncan Reservoir on 1 April 1968, Arrow Reservoir on 1 April 1969, and Mica Reservoir on 1 April 1973. That sale has now expired and all Canadian Entitlement has reverted to British Columbia provincial ownership and is being either delivered to the Canadian-U.S. border or sold directly in the United States.

11. Canada and the U.S. each appointed Entities to implement Treaty provisions, as well as 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 8 February 2012 in Portland.

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

UNITED STATES ENTITY

Mr. Stephen J. Wright, Chairman
Administrator & Chief Executive Officer
Bonneville Power Administration
Department of Energy
Portland, Oregon

Colonel Anthony C. Funkhouser, Member*
Division Engineer
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY

Mr. Chris O 'Riley Chair**
Executive Vice-President,
Generation
British Columbia
Hydro and Power Authority
Vancouver, British Columbia

*COL Anthony Funkhouser replaced COL Robert Tipton (NWD Commander after the retirement of BG McMahon on 15 June 2012), on 27 July 2012.

**Mr. Chris O 'Riley is authorized by his position of Executive Vice President, Generation, to act as Chair of the Canadian Entity by resolution passed by the B.C. Hydro Board of Directors as of 24 February 2012, replacing Mr. David Cobb.

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 Bonneville Power Administration and Corps of Engineers, and in Canada by the B.C. Hydro Board of Directors. Mr. Wright's alternate is Bonneville Power Administration Deputy Administrator, Bill Drummond; and COL Funkhouser's alternate is COL Robert A. Tipton (Deputy Division

Engineer). Mr. O 'Riley does not have a named alternate, but the Canadian Entity has committed to making ad hoc delegations of alternate(s) if and when such action is required.

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.

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
Stephen R. Oliver Vice President, Generation Supply 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	

* Mr. David Ponganis replaced Mr. G. Witt Anderson on 18 May 2012.

UNITED STATES ENTITY SECRETARY	CANADIAN ENTITY SECRETARY
Scott R. Simms* Regional Coordination Power and Operations Planning Bonneville Power Administration Portland, Oregon	Douglas A. Robinson Generation Resource Management B.C. Hydro Burnaby, British Columbia

* Mr. Scott Simms was appointed to replace Dr. Anthony White on 30 April 2012.

Columbia River Treaty Operating Committee

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

UNITED STATES SECTION	CANADIAN SECTION
Richard M. Pendergrass, BPA, Alt. Chair	Kelvin Ketchum, B.C. Hydro, Chair
James D. Barton, USACE, Alt. Chair	Gillian Kong, B.C. Hydro
William D. Proctor, USACE	Herbert Louie, B.C. Hydro
Pamela Kingsbury, BPA*	Alaa Abdalla, B.C. Hydro

* Ms. Pamela Kingsbury was appointed to replace Mr. John Hyde on 3 April 2012.

The CRTOC met during the reporting period to exchange information, approve work plans, discuss issues, agree on operating plans, and brief the Permanent Engineering Board (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;
- Completed the 1 August 2012 through 31 July 2013 DOP;
- Completed one supplemental operating agreement for Canadian storage;
- Implemented the Libby Coordination Agreement (LCA) including the October 2011 update to the Libby Operating Plan (LOP) which involved scheduling of provisional draft, delivery of one average MW of power, and analysis and monitoring of Canadian power effects from Variable Q flood control operation at Libby Reservoir; and
- Briefed the PEBCOM on Entity activities, and completed the 2011 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.

RT Operating Committee at Boundary Dam, July 2012. Pictured are (L to R front row) Gillian Kong (member), Kelvin Ketchum (Canadian Chair), Bill Proctor (member), Rick Pendergrass (U.S. Alternate Chair) (L to R back row) Scott Simms (Secretary), Jim Barton (U.S. Alternate Chair), Renata Kurschner (Canadian Coordinator), Alaa Abdalla, Pam Kingsbury (members)

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 Columbia River Treaty projects in accordance with the Treaty and otherwise assisting the Entities, as needed. The Committee consists of the following four members:

UNITED STATES SECTION	**CANADIAN SECTION**
Ann McManamon, BPA Co-Chair	Stephanie Smith, B.C. Hydro, Chair
Peter Brooks, USACE Co-Chair	Adam Gobena, B.C. Hydro, Member

The CRTHC met twice in the 2011-2012 Operating Year:

Meeting 69: 7 March 2012, B.C. Hydro

Meeting 70: 24 July 2012, Corps of Engineers

In addition, the CRTHC members participated in discussions with CRTOC members and others regarding the results of climate change studies conducted by both B.C. Hydro and the River Management Joint Operating Committee (RMJOC).

The 2011 CRTHC Annual Report was completed in January 2012, and distributed at the annual PEB meeting.

Forecasting

The CRTHC was notified that a new Dworshak forecast procedure was forthcoming for review and approval by the CRTHC. The procedure was deemed not ready, so no review took place. It is expected that a revised procedure will be reviewed and possibly in place in time for the 1 January 2014 official forecast. The Corps' Coordinator, Mr. Ponganis, expects the CRTHC to have first accepted any proposed procedure and then CRTOC, before it is approved and implemented.

This was the first year that the new seasonal volume forecast procedure Ensemble Streamflow Prediction (ESP) was put in place by the Northwest River Forecast Center (NWRFC). The CRTOC had tasked the CRTHC to monitor and evaluate the original recommendation of which specific forecasts to use for treaty purposes. Based on that evaluation, the CRTHC has prepared a revised recommendation for the CRTOC with ESP forecast issue dates that will be the official ones for use in the Treaty Flood Control Operating Plan, the AER and the TSR. In the October 2012 CRTOC meeting, the CRTHC provided these recommendations for forecast dates (typically the 4th working day of the month) for the upcoming year.

The CRTHC will continue to monitor and evaluate the range of ESP forecast lead times to determine what best serves the needs of the Treaty.

Data Exchange

The Corps Columbia Basin Water Management Water Control Data System (WCDS) was forced to migrate to updated servers as a result of the fallout from a Department of Defense Information Assurance audit of one of its districts. Four WCDS staff spent 90 days completing the compliance activities, largely focusing on the approved versions of the Solaris operating system and Oracle database software.

The Corps has issued a requirement to terminate anonymous and non-secure File Transfer Protocol (FTP) at a national level. Any data-reporting office must migrate to secure FTP (sFTP). It is expected that the Corps will stand up a single national sFTP server. B.C. Hydro and BPA have adopted sFTP. A few regional data providers will need assistance to become compliant and the WCDS unit is working with these providers.

B.C. Hydro made major changes to its data reporting infrastructure. They are now able to provide data for a finer temporal time step in an automated fashion and have been able to reduce or eliminate a number of manual processes and spreadsheets.

Stations

CRTHC is working on an updated listing of all Treaty Stations, and will be re-instating letters to agencies which manage Treaty Monitoring Stations to remind them of the importance of the continued operation of these stations. Rather than continue the lengthy debate on the definition of a Treaty Station[1], the CRTHC has decided to take advantage of what was written in the original Treaty language. A Memorandum of Understanding (MOU) between BPA and B.C. Hydro was signed and $100,000 made available to B.C. Hydro for site investigation, permitting and project management. So far, only Keystone Creek is

[1] Treaty facilities were originally those stations recommendation to and adopted by the Entities with the concurrence of the PEB. The system consists of new and existing streamflow and reservoir gauges, snow courses, meteorological stations, and other related hydrometeorological data-collecting facilities, a plan for methods and the frequency of reporting, and a communication system to provide information for the operation of Duncan, Arrow, Mica and Libby reservoirs. It also includes hydrometeorological stations which provide operational and forecasting data relevant to the flow of the Columbia River at Birchbank, British Columbia, or at an equivalent streamflow gauge, and in addition, certain key streamflow and reservoir gauges on the Columbia River downstream from Birchbank and [certain key streamflow and reservoir gauges] on the Clark Fork - Pend Oreille tributary. (*Columbia River Treaty Hydrometeorological Committee 2011 Supplemental Report).* For more information about the hydrometeorological data stations and program, see the hydromet committee's annual reports at: http://www.nwd-wc.usace.army.mil/PB/PEB_08/docHMC.htm.

advancing to the permitting stage. A review of the physical environment at several other existing snow course sites has precluded them as possible sites for conversion to snow pillows. B.C. Hydro and BPA are reviewing several additional sites as future possibilities.

Permanent Engineering Board

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

UNITED STATES SECTION	**CANADIAN SECTION**
Stephen L. Stockton, Chair Washington, D.C.	Jonathan Will*, 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
George E. Bell, Alternate Portland, Oregon	Ivan Harvie, Alternate Calgary, Alberta

* Jonathan Will was formally appointed as the Canadian Chair of the PEB as of 31 May 2012.

The following serve as Secretaries to the Board:

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

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 or flood control operating plans, 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 review. The annual joint meeting of the PEB and the Entities was held on 7 February 2012 in Portland, Oregon, where the Entities briefed the PEB on the preparation and implementation of operating plans, the delivery of the Canadian Entitlement, the 2014 CRT Review, and other topics requested by the PEB.

PEB Engineering Committee

The PEB has established the PEBCOM to assist in carrying out its duties. The members of PEBCOM at the end of this report period were:

UNITED STATES SECTION	**CANADIAN SECTION**
Jerry W. Webb, Chair Washington, D.C.	Ivan Harvie, Interim Chair Calgary, Alberta
Michael S. Cowan, Member Lakewood, Colorado	Darcy Blais, Member Ottawa, Ontario
Kamau B. Sadiki, Member Washington, D.C.	K.T. Shum, Member Victoria, British Columbia

Patrick McGrane, Member
Boise, Idaho

The PEBCOM met with the Operating Committee on 19 October 2011 in Vancouver, British Columbia.

International Joint Commission

The International Joint Commission (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 IJC has appointed local Boards of Control to insure compliance with IJC Orders and to keep the IJC informed. There are three such boards west of the Continental Divide. These are the International Kootenay Lake Board of Control, the International Columbia River Board of Control, and the International Osoyoos Lake Board of Control. The Entities and IJC Boards conducted their CRT activities during the period of this report so that there was no known conflict with IJC orders or rules.

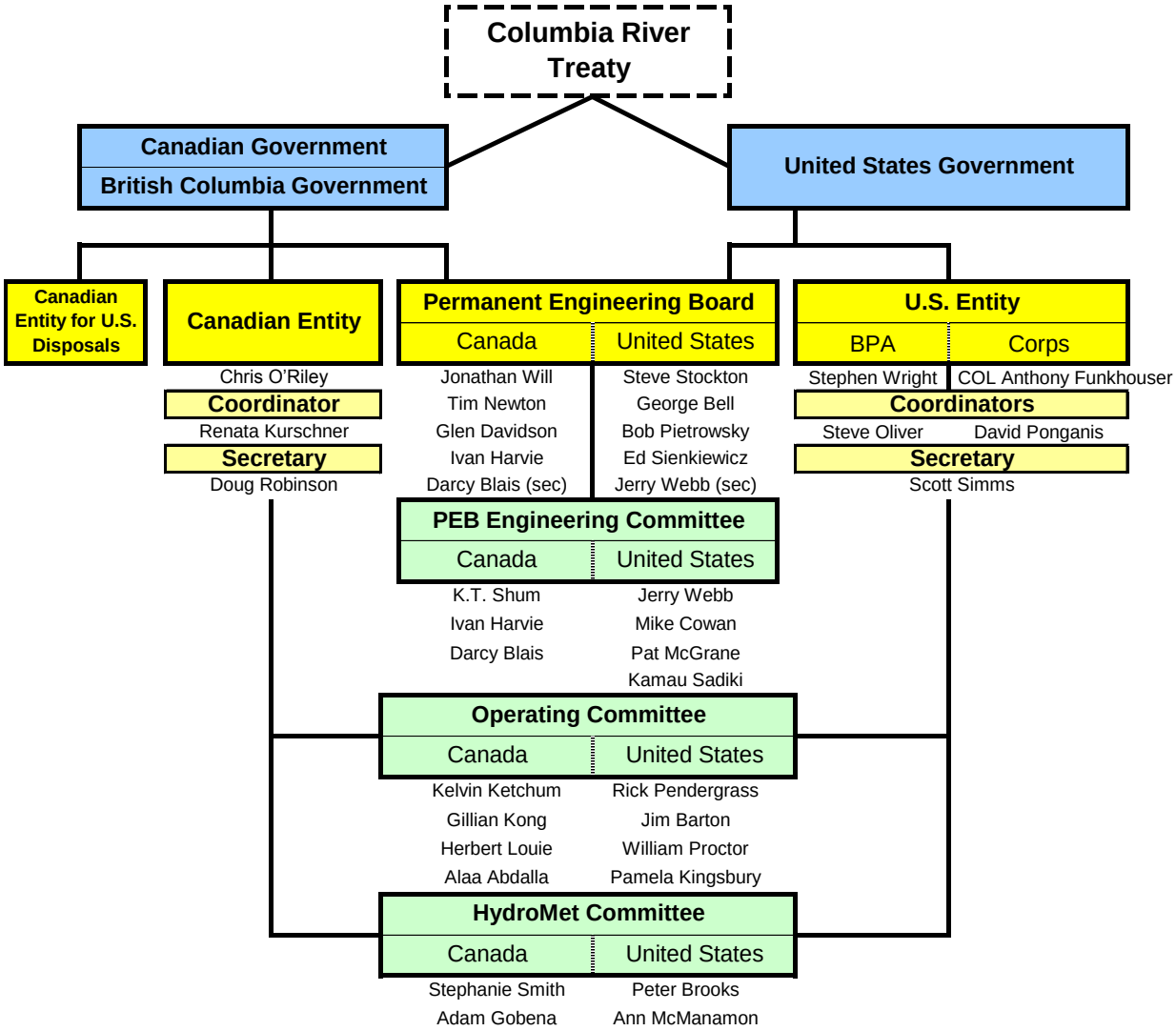
The U.S. Section Chair is Ms. Lana Pollack of Ann Arbor, Michigan. The Canadian Section Chair is Joseph Comuzzi of Thunder Bay, Canada. The Canadian member is Mr. Lyall D. Knott, Vancouver, B.C. The member post previously occupied by Mr. Pierre Trepanier, Montreal, Quebec was vacant as of the publishing of this Annual Report. U.S. members are Mr. Rich Moy of Helena, Montana and Ms. Dereth Glance of Syracuse, New York.

Presentations

During the period covered by this report, CRT personnel made presentations about the history, structure, operations, challenges and communications associated with the CRT to

visitors and inquirers from professional, environmental, academic and civic groups; and individuals; new employees; Northwest Power and Conservation Council staff; law seminar attendees in Vancouver, B.C.; a visitation to the Mekong River area, and presentations to the U.S. Society on Dams Annual Conference; the BPA-NOAA Wind Integration Workshop in Portland, Oregon; the CERI conference in Calgary, Alberta; the U.S. Legislative Council on River Governance; the American Water Resources Association; and the HydroVision Annual Conference in North Carolina. Other presentations were made under the umbrella of 2014/Post-2024 work discussed elsewhere in this report.

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 control 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 control storage diagrams or any variation which the Entities agree will not reduce the desired aim of the flood control plan; and
3. Provides for the development of assured hydroelectric operating plans for Canadian storage for the sixth succeeding year of operation.

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," 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 2011-2012 Operating Year from 1 August 2011 through 31 July 2012. The operation of Canadian storage was determined by the 2011-2012 DOP and supplemental operating agreements. The DOP required a semi-monthly Treaty Storage Regulation (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 2011-2012 AOP, with agreed changes. Most of the hydrographs and reservoir charts in this report are for a 14-month period from August 2011 through September 2012.

Assured Operating Plans

During the reporting period, the Entities completed the 2016-2017 AOP. An Entity agreement approving the 2016-2017 AOP was executed on 5 January 2012. This AOP used the streamline procedures described in Appendix 6 of the Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans for Canadian Treaty Storage (POP) and is based on the 2015-2016 AOP/DDPB hydroregulation studies.

The 2016-2017 AOP establishes Operating Rule Curves (ORCs), Critical Rule Curves (CRCs) Mica and Arrow Project Operating Criteria, and other operating criteria included in the Step I Joint Optimum Power Hydroregulation Study, to guide the operation of Canadian storage. The ORCs were derived from CRCs, Assured Refill Curves (ARCs), Upper Rule Curves (Flood Control Rule Curves), Variable Refill Curves (VRC), Operating Rule Curve Lower Limits (ORCLL), and Variable Refill Curves Lower Limits (VRCLL), consistent with flood control requirements, as described in the 2003 POP. They provide guidelines for draft and refill under a wide range of possible water conditions. The Flood Control Rule Curves conform to the 2003 FCOP and are used to define maximum reservoir levels for the operation of Canadian storage. The 2016-2017 AOP uses the 5.03/4.44 km^3 (4.08/3.6 Maf) Mica/Arrow flood control allocation. The CRCs are used to apportion draft below the ORC when the TSR determines additional draft is needed to meet the Coordinated System firm energy load carrying capability. Because of the use of the streamline procedure, the 2016-2017 AOP operating criteria are a direct carry-over from the 2015-2016 AOP.

During the reporting period, the Entities initiated a full set of studies for the 2017-2018 AOP, which were not completed by the end of the 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, except as noted in the

AOP/DDPB documents and the 2003 POP[2] agreement. For the 2016-2017 DDPB, the Entities agreed to use the optional streamline procedures described in Appendix 6 of the POP.

The total downstream power benefits as a result of the operation of Canadian storage for the 2016-2017 Operating Year were determined to be 2666.3 MW of dependable capacity, and 968.0 average annual MW of usable energy. Therefore, the Canadian Entitlement to downstream power benefits was 1333.2 MW of capacity, which was a 0.9 MW increase from the 2015-2016 DDPB, and 484.0 MW of average annual energy, which was a 4.7 aMW decrease from the 2015-2016 DDPB. The changes to Canadian Entitlement compared to the prior DDPB are caused mainly by the increase in thermal resources due to the increased firm load.

Canadian Entitlement

For the period 1 August 2011 through 31 July 2012, the Canadian Entitlement amount, before deducting transmission losses, was 525.9 aMW of energy, scheduled at rates up to 1314 MW capacity. From 1 August 2012 through 30 September 2012, the amount, before deducting transmission losses, was 504.5 aMW of energy, scheduled at rates up to 1321 MW capacity. The Canadian Entitlement obligation was determined by the 2011-2012 and 2012-2013 AOP/DDPBs.

During the course of the 2011-2012 Operating Year, there were four curtailment events within a span of two months to Canadian Entitlement deliveries, primarily due to a combination of planned maintenance and unexpected weather/load-resource conditions that included system constraints from wind power production. These included a 557 MWh reduction on 1 March 2012, and a 22 MWh reduction the following day. Subsequent reductions included a small 3 MWh reduction on 14 March 2012 and a 43 MWh reduction on

[2] The 1988 Entity Agreements changed procedures for preparation of AOPs from the then-current POP (1983). The agreements resolved issues that delayed completion of the AOP studies, among them whether to use updated estimates of irrigation depletions. The Entities agreed to use updated irrigation depletions and that is reflected in the current POP document. The current POP document (2003) captures changes in methodologies agreed in the 1988 Entity Agreements for preparation of hydroelectric operating plans and the determination of downstream benefits.

24 April 2012. A further 43 MWh curtailment was realized on 9 September 2012 due to forest fires near transmission lines. All of the curtailed power was delivered later within the same month of curtailment, as per agreements between the Entities. The U.S. Entity also invited a BPA transmission system expert to explain to the Columbia River Treaty Operating Committee (CRTOC) at its 23 May 2012 meeting about the operating circumstances and grid congestion events that contributed to these unplanned, pro-rata cuts to firm transmission schedules in the Northwest, which included reductions to the Canadian Entitlement deliveries.

Detailed Operating Plans

During the period covered by this report, the CRTOC used the Detailed Operating Plans (DOP) for 1 August 2011 through 31 July 2012, dated June 2011 and the DOP for 1 August 2012 through 31 July 2013, dated June 2012, to guide Canadian storage operations. These DOPs established criteria for determining the ORCs, proportional draft points, and include other operating criteria for use in actual operations. The 2011-2012 and 2012-2013 DOPs were based respectively on the 2011-2012 AOP and 2012-2013 AOP loads and resources, rule curves, and other operating criteria with agreed changes for both Canadian and U.S. projects. The 2011-2012 and 2012-2013 AOPs included a flood control allocation of 4.43 km^3 (3.6 Maf) in Arrow and 5.03 km^3 (4.08 Maf) in Mica. The 2011-2012 DOP and 2012-2013 DOP operating criteria were used to develop the Treaty Storage Regulation (TSR) studies for implementation of Canadian storage operations. The changes from the AOP were mainly updates to hydro-independent data, incorporation of updated forecast errors and distribution factors, updated plant data and updated Grand Coulee pumping estimates.

The TSR studies were updated twice monthly throughout the reporting period for current inflow forecasts, flood control curves and VRCs, and actual unregulated inflows for the previous month. The TSR and supplemental operating agreements defined the end-of-month draft rights for Canadian storage. The VRCs and flood control requirements subsequent to 1 January 2012 were determined on the basis of seasonal volume runoff forecasts during actual operation. The VRC calculations for Canadian reservoirs and Libby Reservoir for the 2011-2012 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 is 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 Libby Coordination Agreement (LCA), and supplemental operating agreements.

Libby Coordination Agreement

During the period covered by this report, the LCA procedures allowed the Canadian Entity to provisionally draft Arrow Reservoir and exchange power with the U.S. Entity, and required delivery to the U.S. Entity of one (1) aMW, shaped flat, over the entire 2011-2012 Operating Year. Provisional draft operations under the LCA are discussed in Section VI. The most recent Libby Operating Plan (LOP) is dated 14 August 2012.

Entity Agreements

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

Date Signed by Entities	Description of Agreement
5 January 2012	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2016-2017.
10 April 2012	Columbia River Treaty Entity Agreement on the 2011-2012 Non-Treaty Storage Agreement (2012 NTSA).
19 April 2012	Columbia River Treaty Entity Agreement on the Delegation of Certain Provisions of the Libby Coordination Agreement.
8 June 2012	Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Canadian Storage 1 August 2012 through 31 July 2013.

Columbia River Treaty Operating Committee Agreements

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

Date Signed	Description	Authority
30 November 2011	Columbia River Treaty Entity Agreement on Operation of Treaty Storage for Non-Power Uses for 10 December 2011 through 31 July 2012	Detailed Operating Plan 1 August 2011 through 31 July 2012, dated 21 June 2011

Long Term Non-Treaty Storage Agreement

BPA and B.C. Hydro executed a new Long Term Non-Treaty Storage Agreement on 10 April 2012 (2012 NTSA). The agreement provides for coordinated use of up to 6.2 km^3 (5 Maf) of Non-Treaty Storage (NTS) in Canada for the period 10 April 2012 through 15 September 2024. The Entities reviewed the Agreement and are satisfied that mutual benefits can be achieved without adversely affecting the operation of Treaty space in accordance with the Columbia River Treaty or performance of Treaty obligations pursuant to the agreement entitled "Aspects of Delivery of the Canadian Entitlement."

In accordance with the 10 April 2012 Entity agreement, which approved the 2012 NTSA contract between BPA and B.C. Hydro, the CRTOC monitored the storage operations made under the Agreement throughout the operating year to ensure they did not adversely impact operation of CRT storage required by the Detailed Operating Plans (DOP).

Prior to negotiation of a new Long Term agreement, flexibility for shaping flows was provided through the following two agreements:

- 2011 Provisional Storage/Draft Agreement (not Treaty) for the Period 16 October 2010 through 31 December 2011. This short-term agreement included three components: (1) fall storage and release, (2) provisional draft and return, and (3) spring/summer flow shaping.

- Agreement for Use of NTS for the Period 2 September 2011 through 25 November 2011, signed 6 September 2011. This agreement was amended in November 2011 to extend the period of the agreement through 30 March 2012 and expand the volume of storage available for use by BPA and B.C. Hydro. This short-term agreement was intended to provide flexibility prior to implementation of a new Long Term Non-Treaty Storage Agreement.

IV - WEATHER AND STREAMFLOW

Weather for 2011-2012

For the second year in a row, La Nina Pacific Ocean conditions heavily influenced the region's weather. The cooler-than-normal tropical waters, coupled with unusually cool waters throughout the northern and eastern Pacific, set the stage for a second wet and cool operating year across the basin. Unlike the previous year when cool and wet weather persisted throughout the cool season, the weaker La Niña allowed other large-scale jet stream patterns to occasionally overwhelm the La Niña signal, with the sharp temperature and precipitation swings complicating overall system management.

While August is typically the driest month in the Columbia River Basin, August 2011 was particularly dry in the U.S. basins, with only modest precipitation in Canada. Portland, Seattle, and Spokane did not receive measurable precipitation until very late in the month while a few locations, such as the Snake River Basin (Snake Basin) in Idaho, received no rain at all in August. The first period of rather hot weather was noted between 18 and 23 August with temperatures 6-8°F (3-4°C) above average during that period.

September featured the only significant, sustained heat wave of the year between the 6th and 15th. Temperatures were as much as 12°F (6°C) above average during this period. The upper-level high over the northern Rockies that caused the heat wave also kept precipitation out of the region for the first half of the month. A second, shorter, and less intense heat spell was noted toward the end of the month, with only a single but rather strong cold front separating the two events. This single front brought the only significant precipitation of the month to the basin, along with the first mountain snows of the season in Canada.

As the month of October arrived, an unusually variable winter precipitation pattern quickly took hold. Even though precipitation typically increases in the fall as the jet stream makes its fall migration south, in October 2011 the jet stream ingested tropical moisture from the west Pacific and aimed it at the region during the first half of the month. Precipitation was as much as two to four times normal for the first two weeks of October, with only a brief dry spell at mid-month denting the otherwise wet pattern. Because of the tropical origins,

snow levels were unusually high until late in the month when colder north Pacific air masses finally started to arrive.

The weather pattern then did what it would do several more times over the winter and spring of 2011-2012 making a dramatic shift to persistently warm and very dry conditions that was followed several weeks later by an equally dramatic shift to persistently cold and wet weather. So while the November precipitation departures were modest, very large precipitation deficits accumulated over the first two weeks of the month were almost erased by heavy rain and mountain snow (and some new daily precipitation records) during the second half of November.

A similar story can be told about December 2011. A rapid flip to warm and exceptionally dry weather, which began during the last days of November, dramatically flipped toward a much cooler and wetter pattern for the last week of 2011. This time the winter storms that traversed the region were not enough to erase the deficits that accumulated over what is normally one of the wettest months of the year.

In January 2012, wet and cold weather impacted the region for almost four weeks, which included the first appearance of Arctic air in the basin during the middle of the month. This not only brought a rather significant cold snap east of the Cascades and coastal ranges, it lowered snow levels to sea level on several occasions. A significant ice storm impacted the Seattle area and Columbia Gorge on 19 and 20 January with over 300,000 people losing power during the event. February looked very much like December as yet another sharp pattern shift brought unusually warm and dry weather to the region, only to be reversed again toward the end of the month.

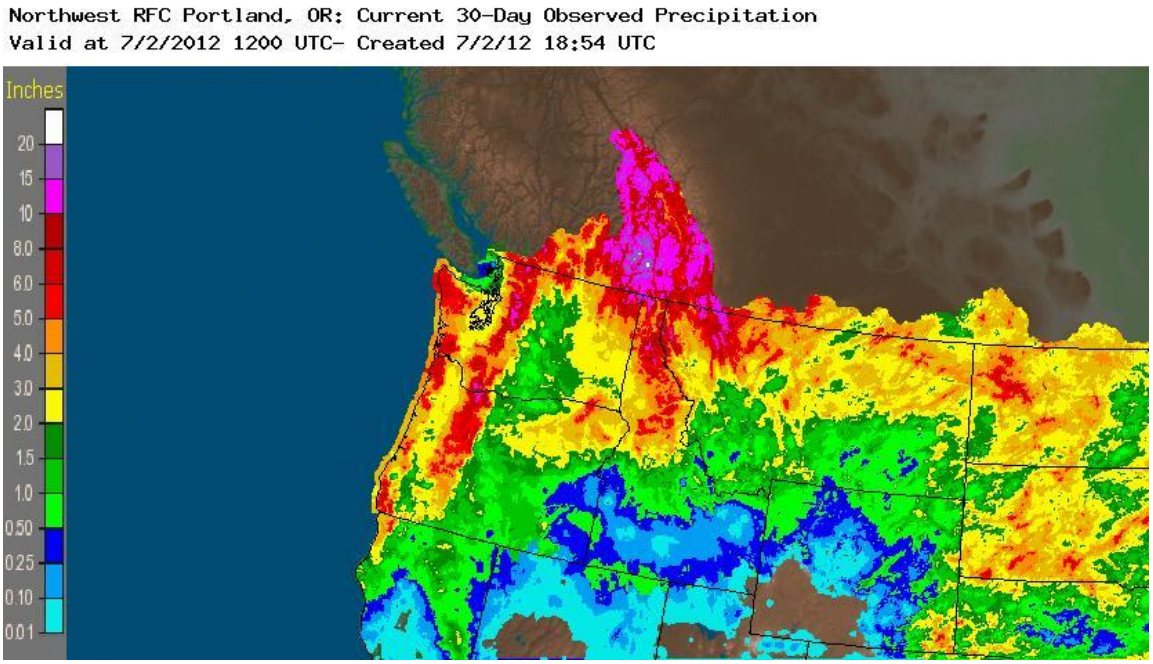
Up until this point in the water year, the large swings between wet and dry periods were canceling each other out. Overall snowpack and winter precipitation totals were near average as February drew to a close. That all changed in March when a decidedly wet and cold pattern persisted across the entire basin for almost six weeks. Daily precipitation and snowfall records were broken across the northern half of the basin during the 1st and 3rd weeks of the month before spreading into the Snake Basin later in March. At the beginning of March, basin-wide snowpack was near normal. By the end of the month, it had jumped to 115 percent of normal.

The extraordinarily wet March spilled into April, although by then the precipitation became more spotty and intermittent. At the end of April an unusual late-season subtropical system traversed the region with heavy precipitation, high snow levels, and considerable rain on snowpack in the U.S. basins. This triggered the first streamflow spike of the spring runoff season, particularly in the Snake basin which had its highest unregulated flow of the entire spring during the last week of the month.

The on again-off again precipitation regimen turned "off" in May. Temperatures remained on the cool side, which combined with well below average precipitation to slow the spring runoff. One exception came at mid-month when several record high temperatures were observed as upper level ridging peaked over the basin.

For the third year in a row, June 2012 went down as one of the wettest on record in the basin and caused significant hydroregulation challenges. In contrast to 2010 where most of the rainfall was in the Snake Basin or in 2011 when the heavy rainfall was spread across the entire Columbia Basin, the heavy rainfall in June 2012 was concentrated in Canada, northern Idaho and Western Montana. Castlegar, British Columbia, received 221mm/8.70 inches of rain in June, which shattered its all-time wettest month record by over 25mm/1 inch (the previous record was set during the Flood of December 1996). Several locations in both the Canadian and U.S. portion of the basin above Grand Coulee had its wettest June on record. Precipitation estimates from NOAA/Northwest River Forecast Center indicated that over 250mm/10inches of rain fell across most of the British Columbia portion of the basin, with isolated mountaintops receiving almost 500mm/20 inches, see Figure 1. While temperatures held well below average during June, the cool temperatures were offset by so much rain on the region's snowpack. There was one notable exception to the otherwise record wetness. The southern Snake Basin, particularly upstream from Brownlee, began to miss out on the storms during the second half of June. By the end of the month, rainfall deficits began to accumulate and impact both regulated and unregulated flows in the region.

Figure 1: Basin precipitation from 1200 UTC 2 June 2012 through 1200 UTC 2 July 2012. (Image from NOAA/National Weather Service)



As the region entered July, the extremely wet and cool weather regime reversed yet again. Drier weather took hold for the entire month, particularly in the Snake Basin where little precipitation was observed and mild drought conditions began to be reported. The precipitation continued in Canada, eastern Washington, and northern Idaho during the first week of the month, but the last significant storm system exited around 4 July, with only spotty thunderstorm activity noted for the rest of the month. Where drought conditions were beginning to take hold over southern Idaho, drying soils and lower humidity led to above average temperatures. Meanwhile, wet soils and the lingering snowpack in Canada held temperatures there a little below average.

By August, though, the developing drought signal in the southern Snake Basin began to spread northward. Like 2011, much drier weather led to steadily decreasing flows throughout the month. By the end of August, and for all of September, natural streamflows had sunk to below long-term averages. The drier weather was accompanied by an extended period of warm weather, punctuated by modest heat waves in mid-August, and again in early September.

Columbia Basin Weather

Location	Temperature Pacific Northwest departure from the 1981-2010 average (ºC / ºF)	Precipitation Columbia River above Coulee percent of the 1981-2010 average (%)	Precipitation Snake River above Ice Harbor percent of the 1981-2010 average (%)	Precipitation Columbia River above The Dalles percent of the 1981-2010 average (%)
August 2011	+1.0 / +1.8	27	60	33
September 2011	+2.6 / +4.7	54	29	45
October 2011	+1.0 / +1.8	144	163	143
November 2011	-0.4 / -0.8	98	70	92
December 2011	-0.4 / -0.8	49	47	52
January 2012	+1.1 / +1.9	111	117	119
February 2012	+0.4 / +0.8	85	83	86
March 2012	+0.4 / +0.8	247	169	202
April 2012	+1.1 / +2.0	141	113	127
May 2012	-0.2 / -0.4	77	82	78
June 2012	-0.5 / -0.9	200	77	164
July 2012	-0.5 / -0.9	113	83	112
August 2012	+1.5/+2.7	34	18	51
September 2012	+1.6/+2.8	26	29	23

Streamflow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 July 2011 through 30 September 2012 are shown on Charts 1 through 7. Libby hydrographs are shown in Chart 8. Observed flows and unregulated flows (computed using the USACE Streamflow Synthesis and Reservoir Regulation (SSARR) model for Kootenay Lake, Columbia River at Birchbank, Grand Coulee, and The Dalles are shown on Charts 9 through 12, respectively. A plot of the flows that would occur at The Dalles if regulated only by the four Treaty reservoirs is provided in Chart 13 along with the observed and unregulated flows at The Dalles for comparison.

The peak-unregulated discharge for the Columbia River at The Dalles was 16617 m^3/s (586.8 kcfs) on 26 June 2012, based on the USACE SSARR 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 SSARR model does. Natural lake effects cause attenuation and dampening of flows, thus the SSARR model simulations provide lower flows than the NWRFC tabulations. As per the table below, the average unregulated August 2011-July 2012 streamflow at The Dalles was above average (116 percent of 1971-2000 average) and approximately 3.6 percent lower than last year's average flow. The total runoff volume at The Dalles during this same time period was 198.1 km^3 (160.6 Maf) based on NWRFC, and is also 116 percent of the average.

Columbia River Unregulated Streamflow

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

	Columbia River at Grand Coulee			Columbia River at The Dalles		
	Unregulated Flow		Percent of	Unregulated Flow		Percent of
Time Period	cfs	m^3/s	Average	cfs	m^3/s	Average
Aug-11	112,006	3,172	107	162,862	4,612	119
Sep-11	61,088	1,730	98	93,489	2,647	100
Oct-11	52,238	1,479	116	99,386	2,814	120
Nov-11	40,535	1,148	83	83,339	2,360	88
Dec-11	31,746	899	74	73,820	2,090	75
Jan-12	31,405	889	75	82,033	2,323	80
Feb-12	32,110	909	70	88,490	2,506	75
Mar-12	61,492	1,741	99	151,738	4,297	97
Apr-12	182,492	5,168	149	360,412	10,206	151
May-12	282,268	7,993	106	474,633	13,440	109
Jun-12	438,776	12,425	142	595,119	16,852	127
Jul-12	304,354	8,618	159	389,249	11,022	151
Aug-Jul Average	**135,953**	**3,850**	**121**	**221,263**	**6,265**	**116**

Seasonal Runoff Forecasts and Volumes

April-August 2012 runoff volumes, 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	1971-2000 Average in Percent
Libby Reservoir Inflow	11.33	9.19	147%
Duncan Reservoir Inflow	3.17	2.57	126%
Mica Reservoir Inflow	17.80	14.43	128%
Arrow Reservoir Inflow	35.02	28.39	124%
Columbia River at Birchbank	66.57	53.97	133%
Grand Coulee Reservoir Inflow	98.52	79.87	132%
Snake River at Lower Granite	29.28	23.74	104%
Columbia River at The Dalles	146.94	119.13	128%

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2012 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, Arrow, 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, Arrow, 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 is prepared by the U.S. Army Corps of Engineers. The 1 April 2012 forecast of January through July runoff for the Columbia River above The Dalles was 139.2 km^3 (112.9 Maf) and the actual observed runoff was 159.7 km^3 (129.4 Maf).

The following tabulations summarize the monthly forecasts since 1970 of the January-July runoff for the Columbia River above The Dalles compared with the actual runoff volume in km^3 and Maf. The average January-July runoff volume for the period of 1971-2000 is 132.4 km^3 (107.3 Maf).

2010 Modified Flows

The 2003 Entity Agreements on Principles and Procedures requires the Entities to use updated estimates of irrigation depletions and return flows when calculating the streamflows required by Treaty Protocol Section VIII for the Steps I, II, and III downstream power benefit studies. The latest PNCA process to update the net depletions and streamflow record to 80 years (1928 to 2009), referred to as the 2010 Modified Flows, and it was completed in August 2011. The 2010 Modified Flows and the updated flood control rule curves, hydro-independent data and other data dependent on the updated streamflows were incorporated in the AOP18 Steps I, II, and III and the DDPB studies.

Historic Seasonal Runoff Forecasts and Volumes

The Dalles, OR Volume Runoff Forecasts in km^3 (Jan-Jul)							
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Actual**
1970	101.8	122.7	115.2	116.3	117.3	--	118.0
1971	136.8	159.7	155.4	165.3	164.1	166.5	169.6
1972	135.8	157.9	171.1	180.2	180.1	180.1	187.1
1973	114.8	111.6	104.5	102.4	99.2	97.1	87.8
1974	151.7	172.7	180.1	183.8	181.3	181.3	192.8
1975	118.5	131.0	141.5	143.9	142.1	139.4	138.6
1976	139.4	143.1	149.3	153.0	153.0	153.0	151.5
1977	93.4	76.7	69.0	71.7	66.4	70.8	66.4
1978	148.0	140.6	133.2	124.6	128.3	129.5	130.3
1979	108.5	97.0	114.7	107.7	110.6	110.6	102.5
1980	109.7	109.7	109.7	110.6	111.8	120.5	118.2
1981	130.7	104.2	104.2	101.0	102.6	118.3	127.5
1982	135.7	148.0	155.4	160.4	161.6	157.9	160.2
1983	135.7	133.2	139.4	149.3	149.3	146.8	146.4
1984	139.4	127.0	120.4	125.8	132.0	140.6	146.9
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
Minimum	93.4	76.7	69.0	69.2	66.4	68.5	66.4
Median	124.6	124.6	120.4	122.7	121.6	123.0	123.0
Maximum	170.2	178.9	180.1	183.8	188.7	196.1	196.1

V - RESERVOIR OPERATION

General

The 2011-2012 Operating Year began with Canadian storage at 99.2 percent full. Libby Reservoir (Lake Koocanusa) was about 1.8 m (6 ft) from full, elevation 747.67 m (2,453.0 ft), at the start of the operating year (1 August 2011) and releasing water to meet BiOp objectives for flow augmentation for listed salmon species in the U.S.

The water supply during the 2011-2012 Operating Year was above average in the Columbia Basin above Grand Coulee, and in the Snake River above Lower Granite. The actual runoff in the Canadian portion of the Columbia Basin measured at Birchbank was about 130 percent of normal for January through July 2012. The actual runoff for the overall Columbia Basin (U.S. and Canada combined) measured at The Dalles for January through July 2012 was 121 percent of normal.

The CRTOC signed one operating agreement during the 2011-2012 Operating Year (see Section III Operating Arrangements). At the end of the 2011-2012 Operating Year, Canadian storage was 100 percent full on 31 July 2012.

Canadian Storage Operation

At the beginning of the 2011-2012 Operating Year on 1 August 2011, actual Canadian storage provided under Article II of the Columbia River Treaty (Canadian storage) was at 18.9 km^3 (15.3 Maf) or 99.2 percent full on 31 July 2011. It drafted to a minimum of 3.6 km^3 (2.9 Maf) on 19 April 2012. Canadian composite storage refilled to 19.1 km^3 (15.5 Maf) or 100 percent full on 31 July 2012.

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 SOAs 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 from Arrow and Duncan Reservoirs. Variances from the TSR target storage operation are accumulated in respective Flex accounts.

An overrun in an account occurs when actual project releases are greater (contents are lower) than those specified by the TSR. Conversely, an under run occurs when actual project releases are less (contents are higher) than those specified by the TSR. Flex accounts for Mica, Revelstoke, Arrow, and Duncan are balanced at all times (i.e., sum to zero) to ensure that under/overruns do not impact the total CRT release required at the Canadian-U.S. border. The terms under/overrun are used in the description of Mica Reservoir operations below.

Mica Reservoir

As shown in Chart 5, Mica (Kinbasket) Reservoir was at elevation 752.6 m (2,469.2 ft) on 31 July 2011. Heavy rain in late September through early October caused the reservoir to continue to fill to reach its maximum 2011 annual elevation of 754.17 m (2474.3 ft) on 3 October, 2011. As is normal, Kinbasket Reservoir was then drawn down during the fall and winter to meet electrical demands. The Upper Columbia generating stations ran relatively hard during the winter of 2011-2012 in order to position the reservoir in anticipation of a large spring runoff volume and an extended spring/summer two-unit outage at Mica.

Kinbasket Reservoir reached a minimum elevation of 722.0 m (2368.7 ft) on 21 April 2012; about 10 feet lower than the 2011 minimum level on 6 May 2011. From early May through mid-July, Mica generation was reduced to near zero as system loads declined. Generation was ramped up across mid-July through August to maximum possible generation with the two in-service units. In addition, to manage the rate of reservoir refill, spill at Mica commenced on 16 July and continued through late August; the first spill at the facility since 1997. The Kinbasket Reservoir reached a maximum level of 754.7 m (2476.0 ft), or 0.55 m (1.8 ft) above full pool on 28 August 2012 as permitted by the CWR. The Kinbasket elevation remained above normal full pool, within 0.3 m (1ft) surcharge, as permitted by the CWR for power purposes, to the end of August when the full power-plant capability was restored.

B.C. Hydro sought and received permission in July from the B.C. CWR to surcharge the reservoir on an interim basis by up to 0.3 m (1ft) up to 754.7 m (2476 ft) for power purposes and by up to 0.6 m (2 ft) to 755.3 m (2478 ft) for flood control purposes. This request was driven by extraordinarily high inflows into Kinbasket Reservoir and severe generation restrictions over

spring/summer 2012. The option to surcharge the reservoir helped to minimize spill amounts and reduce flood flows on the Columbia River.

Inflow into Mica Reservoir was 104 percent of normal over the period August to December 2011. Over this same period, Mica outflow varied from a monthly average low of about 594.7 m^3/s (21 kcfs) in September to a monthly average high of about 991.1 m^3/s (35.0 kcfs) in December. Inflow into Mica Reservoir was about 135 percent of normal over the period January to July 2012, the highest in the last 40 years. Outflow over this same period varied from a monthly average high of 1059 m^3/s (37.4 kcfs) in February to a monthly average low of 51.0 m^3/s (1.8 kcfs) in June.

The Mica project had an under-run of 289.4 cubic hectometers (hm^3) (118.3 thousand second-foot-days (ksfd)) on 31 July 2011. The maximum under-run for the operating period was 1471.7 hm^3 (601.5 ksfd) on 19 September 2011, and the maximum over-run was 1809.8 hm^3 (739.7 ksfd) on 30 June 2012.

Pending completion of the Long Term Non-Treaty Storage Agreement (NTSA), the 2011-2012 Bridge Agreement between B.C. Hydro and BPA was developed and signed in September 2011. This Bridge Agreement facilitated water release from NTS space during the interim period before the NTSA was signed. Terms and provisions in the Bridge Agreement were very similar to those in the Long Term NTSA. Under the initial agreement, each party had up to 1.0 Maf of release rights from NTS, over and above the storage coordinated under the Columbia River Treaty (Treaty). This agreement was expanded, on 21 November 2011, from a draft limit of 1.2 km^3 to 1.85 km^3 (1.0 Maf to 1.5 Maf each). Under this agreement, B.C. Hydro exercised up to its full draft limits of 1.85 km^3 (1.5 Maf) from mid-October through early March and BPA exercised 1 km^3 (0.8 Maf) draft from September through January, resulting in 2.8 km^3 (2.3 Maf) of combined draft (equivalent to about 3 m (10 ft) of incremental draft from both Kinbasket and Arrow reservoirs). The draft balances under this agreement were transferred into the new Long Term NTSA when it was developed and executed on 10 April 2012. Under the 2012 NTSA, 3.5 km^3 (2.8 Maf) of empty Non-Treaty space was completely refilled across June/July 2012 during the peak of the freshet. During this period of unusual runoff conditions on the Columbia system, these agreements provided significant power and flood control benefits for upstream and downstream communities in the Columbia region.

Revelstoke Reservoir

During the 2011-2012 Operating Year, the Revelstoke project was operated as a run of river plant with the reservoir level maintained generally within 0.9 m (3.0 ft) of its normal full pool elevation of 573.02 m (1,880.0 ft). During the spring freshet period, the reservoir operated to a low elevation of 571.65 m (1,875.5 ft), or 1.37 m (4.5 ft) below full pool, to provide additional operational space to control high local inflows. From 17 July to 13 August 2012, Revelstoke was running hard through a combination of generation and spill releases in order to route high flows from Kinbasket Reservoir. Total releases were near, but did not exceed bank-full conditions downstream of the dam. B.C. Hydro also sought and received permission from the CWR to surcharge Revelstoke reservoir on an interim basis by up to 0.3 m (1 ft) to an elevation of 573.3 m (1881 ft) for flood control purposes. However, this option was not exercised.

Arrow Reservoir

As shown in Chart 6, the Arrow Reservoir level was 439.4 m (1441.6 ft) on 31 July 2011, 0.73 m (2.4 ft) below full pool. Due to above normal runoff in the Columbia Basin, Canadian composite storage was operated to its Operating Rule Curve (not proportional draft) throughout the operating period August 2011 – July 2012. During the operating year, the Arrow storage operation was consistent with the DOP TSR, Non-Power Uses Agreement and the 2011/2012 Bridge Agreement between B.C. Hydro and BPA.

Local inflow into Arrow Reservoir was below normal at 81 percent over the period August to December 2011. Arrow outflow varied from a monthly average high of 1630 m^3/s (57.4 kcfs) in August to a monthly average low of 1056 m^3/s (37.3 kcfs) in October. Local inflow into Arrow Reservoir was 125 percent of normal over the period January to July 2012. Outflow over this same period varied from a monthly average low of 680 m^3/s (24 kcfs) in April to a monthly average high of 2520 m^3/s (89.1 kcfs) in July.

A Bridge Agreement was developed between B.C. Hydro and BPA in September 2011 to enable additional releases from Arrow Reservoir for power, flood control and fisheries

benefits in U.S. and Canada pending the Long Term NTSA. Under this agreement, B.C. Hydro exercised up to its full draft limits of 1.5 Maf from mid-October through early March and BPA exercised 0.8 Maf draft in September, December and January. The draft balances under this agreement were transferred into the new Long Term NTSA when it was developed and signed on 10 April 2012. The combined draft under this agreement at the time of signing was 2.8 km^3 (2.3 Maf) or equivalent to about 3 m (10 ft) of incremental draft from both Kinbasket and Arrow Lakes reservoirs. The minimum level reached for Arrow Lakes Reservoir was 427.51 m (1402.6 feet) on 1 April 2012, 3 m (10 ft) higher than the 2011 minimum level.

In December, under terms of the LCA, Canada exercised 137 hm^3 (56 ksfd) of LCA provisional draft. The LCA draft was returned in January and late March, completing just one cycle for this 2011-2012 Operating Year due to unfavorable market conditions.

As in past years, the Non-Power Uses agreement was negotiated between the parties in order to manage Arrow Lakes Reservoir outflows to protect whitefish and rainbow trout spawning and to provide incubation flows downstream of the Hugh Keenleyside Dam. In January, Treaty flows were reduced to enable 1.2 km^3 (1 Maf) of Flow Augmentation storage consistent with the provisions under the Non-Power Uses agreement. As a result, from 1 January to 19 January 2012, Arrow outflow was held on average at about1642 m^3/s (58 kcfs) to maintain low river levels during the whitefish peak spawning period. This operation reduced the number of eggs being dewatered during the incubation and emergence period in February and March 2012. Additionally, both parties mutually agreed to smooth February/March Treaty flows. As such, Arrow outflow, from February through March 2012, was held at about 1274 m^3/s (45 kcfs), on average, to help protect deposited eggs. These flow changes resulted in a Tier 1 protection level for whitefish for the 2011-2012 Operating Year, as defined by arrangements between Canada's Department of Fisheries and Oceans and B.C. Hydro. During April and May of 2012, Arrow outflows were maintained at or above 680 m^3/s (24 kcfs) to support rainbow trout spawning below Arrow at water levels that could be maintained until hatch.

Due to high freshet flows, B.C. Hydro sought and received permission from the CWR to surcharge Arrow reservoir up to 0.9 m (3 ft) above its normal full pool level of 440.1 m (1444 ft) for downstream flood control. As basin inflows increased from snowmelt runoff,

the Arrow Lakes Reservoir refilled rapidly exceeding its normal full pool on 4 July 2012. The reservoir reached its maximum elevation for the year of 440.5 m (1445.3 ft), or 0.4 m (1.3 ft) above full pool on 22 July 2012 the highest level since 1990. Downstream flood control operation began when Columbia River flows at Birchbank exceeded 467 m^3/s (165 kcfs) on 24 June 2012. To reduce peak flows, 3.5 km^3 (2.8 Maf) of empty Non-Treaty space (1.5 Maf B.C. Hydro Active, 0.8 Maf BPA Active and 0.5 Maf of Recallable) was completely refilled from June to July 2012 providing significant flood control benefits for downstream communities in the Columbia region during this period of unusual runoff conditions on the Columbia system. Even with surcharging Arrow and utilizing empty Non-Treaty space, the Columbia River flows at Birchbank (downstream of the Kootenay and Columbia confluence) peaked at 6090 m^3/s (215kcfs) on 21 July 2012, the highest flow recorded since the beginning of full Treaty dam operation. Birchbank flows returned to non-flood levels when it reached 4670 m^3/s (165 kcfs) on 1 August 2012. Arrow operation returned to non-flood operation when the reservoir returned to normal full pool, 440.13 m (1444 ft) by 30 July 2012. The reservoir then proceeded to draft across the summer months reaching 433.9 m (1423.7 ft) by 30 September 2012.

Duncan Reservoir

Operation of the Duncan Reservoir during the 2011-2012 Operating Year implemented the operational constraints agreed upon in the Duncan Water Use Plan and ordered in the Water License Order (issued on 21 December 2007). As shown in Chart 7, the Duncan Reservoir refilled to 576.71 m (1892.2 ft) or 0.03 m (0.2 ft) above normal full pool on 1 August 2011. Duncan discharges were adjusted as needed from August through 5 September (Labor Day) to target a reservoir elevation of ~574.9 +/-0.3 m (~1,886 +/-1 ft) for the Spillway Operating Gate rehabilitation work starting mid-October.

After Labor Day, Duncan discharges were increased to maintain flows at the Duncan River below Lardeau 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 Dam . For the first three weeks of October, discharges were reduced to maintain a 73 m^3/s (2.6 kcfs) flow at DRL to facilitate spawning at lower flows to limit the risk of over-winter dewatering of redds. Discharges were increased in the last week of

October 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 help support whitefish flows downstream of Keenleyside Dam and to meet month-end Treaty flood control requirements. For the first three weeks of January 2012, Duncan discharge was kept fairly high at 250 m^3/s (8.8 kcfs) at DRL, in order to continue to draft Duncan Reservoir and to help reduce Arrow flows in aid of whitefish spawning. Duncan flows were adjusted across the balance of January and February to meet Treaty flood control target of 552.5 m (1812.5 ft) by 29 February 2012.

In most years, Duncan Reservoir is drafted to near empty between mid-April and early May. Duncan Reservoir reached its minimum level for the year of 547.0 m (1794.7 ft) on 14 April 2012. By comparison, in 2011 the reservoir reached a minimum elevation of 546.9 m (1794.2 ft) on 1 May 2011. The project was operated to provide the agreed minimum flow of 73 m^3/s (2.6 kcfs) flow at DRL as required for fish until late April when freshet started abruptly and the Duncan Dam discharge was gradually increased to 113 m^3/s (4 kcfs).

Reservoir discharge was reduced to a minimum of 3.0 m^3/s (0.1 kcfs) on 7 June to refill the reservoir and reduce flood levels on Kootenay Lake. In response to significant rainstorms in June and July, B.C. Hydro applied and received permission from the CWR to store 0.6 m (2 ft) above the maximum elevation in mid-July to mid-August up to 577.3 m (1894 ft). Releases from Duncan Reservoir were held at minimum until early July to avoid increasing the peak level of Kootenay Lake, which was the highest since 1974. Once the Kootenay Lake level began to recede, Duncan discharges were increased on 7 July to manage the rate of refill for Duncan Reservoir.

By 20 July 2012, Duncan Reservoir reached full pool, and then surcharged by 0.3 m (1 ft) over its full pool level to 577 m (1893 ft) on 23 July, reaching its highest level recorded since the dam began operation in 1967. This operation reduced downstream discharges and flood damages immediately downstream, with relatively little impact around Duncan Reservoir. The Duncan River flow at DRL peaked well above the normal maximum at 575 m^3/s (20.3 kcfs) on 23 July 2012. As inflows subsided, Duncan discharges were adjusted as needed from August through 3 September (Labor Day) to target a reservoir elevation of ~575.5 +/- 0.3 m (~1,888 +/- 1 ft). For the balance of September until the ramp down starts

on 25 September, project flows are increased to maximum DRL of 250 m^3/s (8.8 kcfs) to draft the reservoir before minimum flow period in October.

Libby Reservoir

Operation of Libby Dam and Lake Koocanusa is shown in Chart 8 of this document. Lake Koocanusa ended July 2011 at elevation 747.64 m (2452.9 ft). During early July 2011 the project used up its Sturgeon Augmentation volume of 1.2 maf and filled slowly throughout the month. Libby continued to fill during the first few days of August 2011, reaching a peak elevation of 747.80 m (2453.4) ft) on 4 August. Libby began August 2011 with a constant outflow of 396 m^3/s (14 kcfs) and then ramped up to 453 m^3/s (16 kcfs) on 4 August to facilitate the implementation of a Special Operations Request (SOR) approved at the 3 August Technical Management Team (TMT) meeting. The SOR was presented by the Kootenai Tribe for reduced outflows in September and October to allow for habitat improvement work below Libby Dam. This habitat work would be part of the first phase of the Master Plan for the Kootenai River, as coordinated with the Kootenai Conservation and Restoration Plan and the USFWS Bull Trout Biological Opinion (BiOp). Specifically, the SOR requested a flow of 170 m^3/s (6 kcfs) in September and 113 m^3/s (4 kcfs) in October. TMT members agreed to operate Libby to advance the target elevation of 746.46 m (2449.0 ft), the typical NOAA Fisheries BiOp target for 31 August, to a date prior to 31 August, and then reduce outflows to the requested rates, thereafter. Libby ramped down to 413 m^3/s (14.6 kcfs) on 15 August due to a unit going out of service for maintenance. Flows were adjusted again, down to 396 m^3/s (14 kcfs) on 27 August ramping down further on 30 August to 340 m^3/s (12.0 kcfs) and beginning the reduction from the 340 m^3/s (12 kcfs) to 170 m^3/s (6 kcfs), following USFWS BiOp ramping rates on 31 August.

The flat discharge of 170 m^3/s (6 kcfs) was reached on 5 September 2011, and was held for the remainder of the month. The 170 m^3/s (6 kcfs) discharge is also the minimum flow required in September for bull trout pursuant to the USFWS Bull Trout BiOp. Libby began September at elevation 746.06 m (2447.7 ft) and ended the month at 745.78 m (2446.8 ft), drafting slightly over the month.

By 3 October 2011 the discharge had been reduced to 113 m^3/s (4 kcfs), the minimum project outflow. The flow was maintained throughout the month, as the habitat restoration work continued. The project filled about 1.5 feet over October, reaching 746.24 m (2448.3 ft) on 31 October. On 1 November, Libby outflows were increased to 170 m^3/s (6 kcfs) and held there until 8 November, to allow completion of this season's habitat restoration work. The outflow was then ramped up to 255 m^3/s (9 kcfs) and then ramped up further for purposes of flood control draft with associated power benefits, typical of the fall drawdown period. With the onset of cold weather, during the weekend of 19 November, Libby was brought up to full powerhouse, 708 m^3/s (25 kcfs). The project ended November at elevation 747.77 m (2435.3 ft), with some weekly shaping in outflow, which averaged 382 m^3/s (13.5 kcfs) over the entire month. All changes in outflow followed the ramp rate restrictions as described in the 2006 USFWS BiOp.

The December water supply forecast came in at 93 percent of average allowing a slight relaxation to the end of December's target elevation, targeting 735.18 m (2412 ft). Full draft according to VARQ and standard flood control is 734.87 m (2411 ft), for 31 December. In December the project drafted for flood control with shaping for power interests. The project's actual elevation on 31 December was 735.31 m (2412.44 ft) and minimum outflow, 113 m^3/s (4 kcfs), was reached on 31 December at 2400 hours, not quite meeting the designated elevation target. Libby outflow averaged 510 m^3/s (18 kcfs) in December and inflow averaged 3.4 kcfs or 86 percent of average. Precipitation over the Kootenay Basin in December was well below normal, at 40 percent of average.

For all of January and February 2012 the Libby project stayed at minimum outflow of 113 m^3/s (4 kcfs) except for a brief time for unit testing. Throughout January and February the project drafted over 4 feet while staying at minimums, reaching 733.90 m (2407.8 ft) on 1 March. Reservoir levels remained significantly below the VARQ required flood control elevation of 739.51 m (2426.2 ft) for the end of January and 740.42 m (2429.2 ft) for the end of February. The Corps's official January Water supply forecast was 6.8 km^3 (5.5 Maf) or 86 percent of average using the 1929 – 1999 period of record and the February forecast rose slightly to 7.0 km^3 (5.7 Maf) or 90 percent of average. While the water supply forecasts stayed slightly below normal, the dry December events were replaced by wetter conditions beginning with the New Year. Precipitation for January and February, respectively averaged

103 percent and 84 percent of normal with temperatures near normal. By the end of February the snow pack was near average over most of the northern basin, with higher values further north.

The Corp's March water supply forecast stayed about the same as the February forecast and was 6.9 km^3 (5.6 Maf) or 89 percent of average. The end of March upper rule curve target was set at 742.40 m (2435.7 ft) using VARQ rules. For the northern portion of the Columbia Basin, March started with seasonable temperatures and mostly with high pressure in place. Conditions quickly turned around during the second week of the month and March ended as an extremely wet month. A persistent northwesterly jet stream brought storm after storm from the Gulf of Alaska and the Eastern Pacific into the region. According to the NWRFC, the Kootenay Basin received 297 percent of average precipitation in March. Temperature in the basin was average to slightly below average over the month.

Based on the changing weather and increasing inflow forecast, the Seattle District elected to increase outflows about mid-March, first to two units, about 254.9 m^3/s (9 kcfs), and then to three units, about 481.4 m^3/s (17 kcfs). The projected ended March at elevation 732.28 m (2402.5 ft). The water supply forecast increased substantially in April, to 8.5 km^3 (6.9 Maf) or 108 percent of average. For most of April the project operated between three units 481.4 m^3/s (about 17 kcfs) and full powerhouse, operating at or near full powerhouse from 5 April until 18 April (per the VARQ operating rules, during evacuation and until the initiation of refill, Libby outflows are limited to hydraulic capacity of the powerhouse to the best extent possible, which resulted in Libby pool elevations being above the Flood Control Rule Curve for more than a week in mid-April). System refill was triggered on 24 April, allowing the Libby project to retroactively start refilling ten days prior. The reservoir drafted to its lowest elevation of 725.7 m (2380.9 ft) on 23 April 2012. Libby ended April at elevation 728.53 m (2390.2 ft) following VARQ rules and also adjusting releases briefly near the end of the month to stay on the refill curve. Releases on 27 April were reduced to an average of 9.8 kcfs due to flooding concerns at Bonners Ferry. April was characterized overall by above average precipitation and near average temperatures in the Kootenay Basin, with precipitation at 131 percent of average during the month. Late in April, high pressure built up over the region, but this high pressure also helped start off typical spring diurnal convection, bringing thunderstorms to the region. Libby inflows averaged 104.8 m^3/s

(3.7 kcfs) in March and 382.3 m^3/s (13.5 kcfs) in April. Libby outflow averaged 203.9 m^3/s (7.2 kcfs) in March and 19.7 kcfs in April.

The May water supply forecast was calculated to be 8.9 km^3 (7.2 Maf), or 113 percent of average. This value required a Sturgeon flow augmentation volume of 1.5 km^3 (1.18 Maf). Through a court ordered stipulation, the project was directed to spill up to 283.2 m^3/s (10 kcfs) above full powerhouse discharge in order to produce the required river levels below the project believed optimum for Sturgeon reproduction. In May the project followed the refill curve and applied VARQ rules staying at or above VARQ flows. Based on the May water supply forecast the VARQ flow was 379.4 m^3/s (13.4 kcfs), but at times during mid-month daily average outflow was increased above that level in order to control the rate of refill. From 14 May through 18 May Libby outflow averaged 441.7 m^3/s (15.6 kcfs). The project ended with May elevation at 737.74 m (2420.4 ft). In contrast to the two previous months, May was a relatively dry month, with precipitation within the Kootenay Basin averaging 72 percent of average. Temperatures during the month were below average. Snow pack at the end of May was well above average in the northern portion of the Kootenay Basin and slightly above average in the southern portion.

The Corps official water supply forecast for June came in at 7.24 MAF or 114 percent of average. The ramp up operations for the Sturgeon pulse flows was initiated on 28 May, with some spill added by 4 June. Conditions then turned wet early in the month as a particularly strong rain event with wrap-around moisture from the southeast occurred between 6 June and 8 June. Annual peak inflows to the project peaked on 7 June at 2154.9 m^3/s (76.1 kcfs). The Sturgeon operation was planned so as to bring the Bonners Ferry stage within a foot of 537.66 m (1764 ft). With the continuing strong storm activity in the region, the actual Sturgeon operation, with planned spill of up to 283 m^3/s (10 kcfs), was modified at times to an operation below powerhouse flows in order to control Bonners Ferry below flood stage. Flows from Libby ranged from near full powerhouse 708 m^3/s (25 kcfs) to 963 m^3/s (34 kcfs) beginning 7 June and continuing through 21 June. As the rainstorms continued, the operation transitioned to a maximum pool control and a flood risk management operation. Conference calls with the regional stakeholders and Emergency Management were initiated on 25 June. Shortly thereafter, on 27 June conference calls were held with Canada followed by formal conference calls with Canadian stakeholders beginning on 28 June. Operations were initially

designed to stay below flood stage at Bonners Ferry 537.67 m (1764 ft). Subsequently, these operations were modified to exceed flood stage in order to control the Lake Koocanusa refill rate. A second inflow peak, slightly lower than the one realized on 7 June, was recorded on 27 June at 2123.8 m^3/s (75 kcfs) due to a series of progressive strong localized rain events passing and sometimes stalling over portions of the Kootenay Basin. At the same time, Kootenay Lake was also rising due to the rain response in Canada and high Libby discharge, 1133 m^3/s (40 kcfs). A coordinated (U.S. and Canada) deviation request for a change in operations was approved by the Corps on 28 June to allow Libby Reservoir to surcharge above the maximum 749.50 m (2459.0 ft) pool elevation by 1-foot, up to elevation 749.81 m (2460.0 ft). (Per Article XII (5), if a variation in the operation of the storage is considered by Canada to be of advantage to it the United States of America shall, upon request, consult with Canada. If the United States of America determines that the variation would not be to its disadvantage it shall vary the operation accordingly). This temporary flexibility to fill above the normal full pool allowed the project to maintain a lower release essentially shifting (reducing) special curve releases and thus providing stage reduction benefits downstream in the U.S and Canada. Despite the ability to surcharge, outflows were increased to 1302.6 m^3/s (46 kcfs) on 28 June. On 3 July the deviation was modified and superseded with an allowance to be able to surcharge up to elevation 750.11 m (2461.0 ft). One additional increase in flow was required on 3 July, to 1359.2 m^3/s (48 kcfs).

Major storm systems moved out of the region by 3 July, with some recurrences of convective localized rain through the middle of July. The stage at Bonners Ferry peaked out at 538.46 m (1766.59 ft), early on 4 July, nearly coinciding with peak stage on Kootenay Lake at Queens Bay, which peaked out near 534.56 m (1753.8 ft). With outflows at 1359.2 m^3/s (48 kcfs) the Libby reservoir reached a high of 749.77 m (2459.88 ft) on 5 July. With the surcharge operation approved and a desire to provide downstream relief, project outflows were gradually reduced to 1217.6 m^3/s (43 kcfs) by 9 July with the reservoir drafting slightly. With outflows still at 1217.6 m^3/s (43 kcfs), Libby then filled again slightly to a record high level of 749.80 m (2459.96 ft) on 14 July, and then again on 16 July due to modest inflow rises associated with convective precipitation. Peak elevation was 0.3 m (0.96 ft) above the normal full pool of 749.5 m (2459.0 ft). Libby inflow averaged

1648.0 m^3/s (58.2 kcfs) in June and 1064.7 m^3/s (37.6 kcfs) in July. Libby Outflow averaged 889.1 m^3/s (31.4 kcfs) in June and 1064.7 m^3/s (37.6) kcfs in July.

From mid-July to the end of August the project was drafted slowly with outflows reduced gradually to 339.8 m^3/s (12 kcfs) by 24 August in preparation for the second and continuing season of the habitat restoration work requiring lower flows in September and October. The request for the special flow operation, which influenced reservoir levels, was presented to the TMT (and approved) as a System Operation Request (SOR). Outflow was gradually stepped down to 226.5 m^3/s (8 kcfs) by 3 September. The reservoir drafted to elevation 747.31 m (2451.7 ft) by 31 August 2012 and to elevation 746.3 m (2448.34 feet by 30 September 2012. The final April – August inflow volume to the project was 11.3 km^3 (9.2 Maf or 147 percent of normal (1971 – 2000, 30 year normal).

Kootenay Lake

As shown in Chart 9, the level of Kootenay Lake at Queens Bay was 532.32 m (1,746.47 ft) on 31 July 2011. As runoff receded in August, Kootenay Lake continued to draft and discharges were adjusted to control the lake level below the IJC Order reference level. When the Kootenay Lake level measured at Nelson was drafted below the threshold level of 531.36 m (1,743.32 ft) on 27 August 2011, discharges were adjusted to keep the lake level at or below this control level until the end of August.

Kootenay Lake was then operated to target minimum flows in the Kootenay River at the mouth of Brilliant Dam. Operations targeted minimum flows of 510 m^3/s (18 kcfs) from December to September and 453 m^3/s (16 kcfs) during October and November, although the target flows are subject to water availability. Due to low basin inflows, the flows at Brilliant Dam was gradually reduced below target in late September to 453 m^3/s (16 kcfs) to prevent further drafting of Kootenay Lake and to conserve water for fish. With prolonged dry conditions, further reduction in flow to about 400 m^3/s (12 kcfs) at Brilliant Dam was implemented in late October. By mid-November, as Libby discharges increased, Brilliant Dam flows were increased to meet target minimum flows. As Libby increased generation in December, there were sufficient flows to support higher releases from Brilliant Dam ranging from 501– 1020m^3/s (18 to 36 kcfs). By 31 December 2011, Kootenay Lake was positioned

at an elevation of 531.6 m (1,744.1 ft), ~0.4 m (~1.3 ft) below the maximum IJC Order reference level to avoid spill during a generating unit outage. In the first half of January, the Brilliant Expansion power-plant was out of service and discharges were kept between the minimum target of 509.7 m^3/s (18 kcfs), and the 594.7 m^3/s (21 kcfs) maximum Brilliant Dam discharge, but due to low inflows, discharges were reduced to 424.8 m^3/s (15 kcfs) in February. Brilliant Dam expansion projects increased generation in March when Kootenay Lake was drafted as required by the IJC rule curve. From 18 March onwards the Corra Linn and Kootenay Canal projects were operated to maximize discharges from the lake, limited only by the channel constriction through Grohman Narrows.

Despite maximum flows from the lake, the Kootenay Lake level exceeded the IJC Order reference level on 28 March 2012 and remained above the IJC level until the declaration of spring freshet. During this time Corra Linn and Kootenay Canal projects were operated to discharge maximum possible ("free fall conditions"). On 26 March 2012 the lake reached its annual minimum level of 530.2 m (1739.6 ft). By comparison, on 4 April 2011 Kootenay Lake reached a minimum elevation of 530.5 m (1740.5 ft).

The International Kootenay Lake Board of Control, after consultation with FortisBC declared the Commencement of Spring Rise for Kootenay Lake on 20 April 2012. Following this declaration, the Corra Linn and Kootenay Canal projects continued to pass maximum discharge, limited only by Grohman Narrows throughout the spring runoff period. Kootenay Lake reached a peak level of 534.6 m (1753.8 ft) on 3 July 2012, highest level since 1974. Without the operation of the upstream Duncan and Libby dams, the peak level of Kootenay Lake would have been approximately 2 m (7 ft) higher based on simulations from the unregulated basin model. This would have caused extensive flood damage around the lake. The Treaty coordinated surcharge at Lake Koocanusa reduced the peak Kootenay Lake level by an estimated 0.3 feet and reduced flood damages in Canada and upstream into the U.S. (e.g. Bonners Ferry). By comparison, on 15 June 2011 the peak level was 532.97 m (1751.7 ft). Discharge from the lake peaked at 2780m^3/s (98 kcfs) on 2 July 2012.

As runoff receded during July, Kootenay Lake drafted and discharges from the lake continued to be maximized until the reservoir drafted to 533.1 m (1749.0 ft) on 30 July 2012. At this time the Corra Linn spill was gradually reduced and the Corra Linn forebay returned to its normal operating level. In August, lake discharges were adjusted to draft Kootenay

Lake according to the IJC curve and target a Kootenay Lake level of ~ 531 m (1742 ft) by 15 September for the kokahee shoal spawner operation.

VI - POWER AND FLOOD CONTROL ACCOMPLISHMENTS

General

During the period covered by this report, Duncan, Arrow, and Mica reservoirs were operated for power, flood control, 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 2010-2011 and 2011-2012 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 ORC, CRCs, Mica/Arrow project operating criteria, and non-power constraints as utilized 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, Arrow 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.

During the period covered by this report, Libby operated for power in October and November as described in the LOP. The December forecast was 93 percent of the 71-year average. Based on this forecast, the recommended draft for Libby Reservoir was 2.42 km^3 (1.965 Maf), to elevation 735.2 m (2412 ft) on 31 December.

Libby was operated to its Variable Flow flood control storage reservation diagram. Both Libby and Duncan dams began refill at the end of April according to the ICF date, and in July operated to manage local and downstream flood control in response to the late season high runoff in the Upper Columbia and Kootenay Basins.

Flood Control

Due to late season rain, the 2012 water supply forecasts in most of the sub-basins of the Columbia River Basin had rising trends as the months progressed. This was especially so in the Upper Columbia Basin, as well as the Kootenay and Pend Oreille basins. The rising forecasts caused flood control targets to become more stringent towards the end of the season, and also caused surcharge operations at some of the dams. The observed seasonal water supply volumes at all the various Columbia sub-basins were above average with the exception of the Snake Basin, where it was about average.

During the drawdown period, the reservoir system, including the Columbia River Treaty projects, is required to draft for flood control in preparation for the spring rise. Inflow forecasts and reservoir regulation modeling were done throughout the winter and spring. Mica, Arrow and Duncan were operated according to the May 2003 FCOP. Libby was operated to its VARQ Storage Reservation Diagram. The unregulated peak flow (based on the USACE SSARR program output) at The Dalles, Oregon, shown on Chart 13, was estimated at 16617 m^3/s (586.8 kcfs) on 26 June 2012, and a regulated daily peak flow of 11737 m^3/s (414.5 kcfs) occurred on 27 June 2012 as measured at the United States Geological Survey gage at The Dalles, Oregon. The unregulated (USACE) peak stage at Vancouver, Washington was calculated to be 6.23 m (20.4 ft) on 27 June 2012, and the peak observed stage was 4.78 m (15.7 ft) on 2 April 2012, just shy of the NWRFC's flood stage for Vancouver at elevation 16 feet. The peak observed stage occurred so early in the season due to high flows from the Willamette during that period.

In 2011-2012 Operating Year, the Canadian Entity had elected to operate Mica and Arrow to the flood control 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 Mica, as allowed under the 2003 FCOP. This allocation was first incorporated in the AOP for 2006-2007.

Computations of the Initial Controlled Flow (ICF) for system flood control operation were made in accordance with the Treaty Flood Control Operating Plan. For 2012, the computed ICFs at The Dalles based on the various first-of-month water supply forecasts, are as follows:

Initial Controlled Flow (ICF) at TDA

Based on	kcfs	m^3/s
January Forecast	286.9	8123
February Forecast	307.9	8718
March Forecast	337.8	9564
April Forecast	392.8	11123
May Forecast	416.1	11781

Refill at the projects commence according to the date when the unregulated flow at The Dalles is expected to equal or exceed the ICF. For WY 2012, the ICF date was declared as 24 April based on the April forecast ICF of 392.8 kcfs. The flood control objectives at The Dalles were for regulated flows to stay within a specified range of daily average and instantaneous maximum flows. These ranges and maximum values varied throughout the refill season. As mentioned earlier, the observed daily peak flow at The Dalles this year was 14113 m^3/s (414.5 kcfs), occurring on 27 June 2012. 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. As shown in the chart, starting 30 April Arrow Reservoir filled faster relative to Grand Coulee compared to the guideline. Arrow Dam was operated to meet local as well as system flood control objectives. Arrow Reservoir surcharged beyond full pool by up to 0.46 m (1.5 ft) in July due to the late season high runoff, to reduce flood risk at Birchbank, British Columbia. A deviation for Arrow had been approved early in the season (17 May) to raise the flood risk management curve by 0.3 km^3 (0.26 Maf), which is equivalent to the storage space between elevations 440.1 m and 440.7 m (1444 ft and 1446 ft). Throughout most of the drawdown period, Grand Coulee was operated below the flood control elevation limits due to increasing water supply forecasts. This helped in maintaining the flood control objectives at The Dalles. Refill at Grand Coulee was delayed due to the delayed runoff.

In addition to Arrow, surcharge operations also occurred at Mica, Duncan, Libby and Hungry Horse dams to mitigate the late season runoff. High rainfall and snowmelt in the Upper Columbia and Kootenay Basins led to high streamflows and therefore local flooding concerns. In the Upper Columbia Basin, Mica reservoir surcharged above full pool in late

July by up to 0.3 m (1ft) to reduce flood risk at Birchbank, British Columbia (peak flow = 6060 m^3/s, 214 kcfs). In the Kootenay Basin, Duncan and Libby reservoirs surcharged above their full pools up to approximately 0.3 m (1ft) each from early to late July. High elevations were reached at Bonners Ferry, Idaho (peak stage =1766.4 ft) and Kootenay Lake, British Columbia (peak stage =1753.8 ft). Local flows in the basin were also high, contributing towards the high stages. In the Pend Oreille Basin, Hungry Horse Reservoir surcharged by about 0.15 m (0.5 ft) in late June due to late season high runoff volume. The surcharge operation occurred due to outflow restrictions at the dam, and also to reduce flood risk at Columbia Falls, Montana.

Deviations were not required for the surcharge operations at Mica, Duncan and Hungry Horse as surcharge is part of their approved operations, but deviations were required at Libby and Arrow. A deviation had previously been approved for Arrow Reservoir on 17 May to raise the flood risk management curve elevation. After coordination with Canada, two deviations were approved at Libby Reservoir that allowed a surcharge for up to 0.3 m (1 ft), and then up to 0.6 m (2 ft) was approved on 28 June and 3 July, respectively.

Runoff volumes were about average in the Snake Basin and flood control operations there were normal.

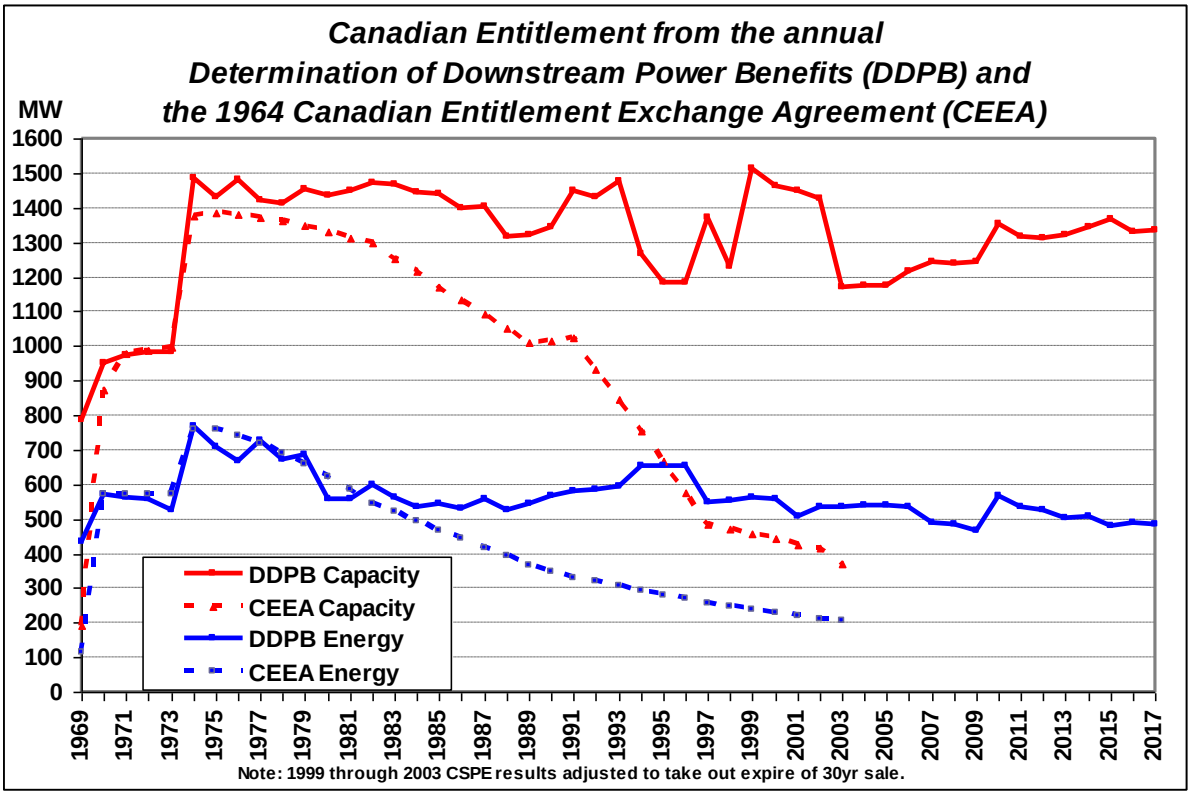
Canadian Entitlement and Downstream Power Benefits

From 1 August 2011 through 30 September 2012, 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.

No Entitlement power was disposed directly in the U.S. during 1 August 2011 through 30 September 2012, as allowed under specific provisions of the 29 March 1999 Agreement on “Disposals of the Canadian Entitlement within the U.S. for 4/1/98 through 9/15/2024.”

The following Figure 2 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 2: 2011-2012 Determination of Canadian Entitlement



The CEEA estimates of the Canadian Entitlement were based on the 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 and the CEEA estimate.

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, 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).

2014/2024 Review

During the period of this Annual Report, the U.S. Entity continued interaction with state, federal and Tribal representatives with regard to potential future Treaty actions. The U.S. Entity engaged the Sovereign Review Team and Sovereign Technical Team to advance development of flood risk management, hydropower and ecosystem based alternatives for consideration in making recommendations to the U.S. State Department regarding future Treaty actions.

Consultation between the U.S. Entity and the U.S. State Department continued and State Department representatives began attending outreach and stakeholder sessions as observers. While the Canadian Entity had no authorization or funds from the Province of British Columbia to continue joint Treaty analysis and work during the period, it did continue during the year to coordinate with its stakeholders on future Treaty options. In addition, Canadian representatives from B.C. Hydro provided feedback, as requested on U.S. studies, related to proposed Post 2024 procedures and potential future Canadian power operations. Canada is also pursuing their own separate analysis on post 2024 operations.

The CRT Review team completed work on the first iteration of analyses of the reference conditions treaty operating scenarios and presented preliminary results to the Sovereign teams and stakeholders. Based on those results the CRT Review team is continuing to refine the evaluation tools and moving toward the completion of their evaluation and development of recommendations to the U.S. Entity.

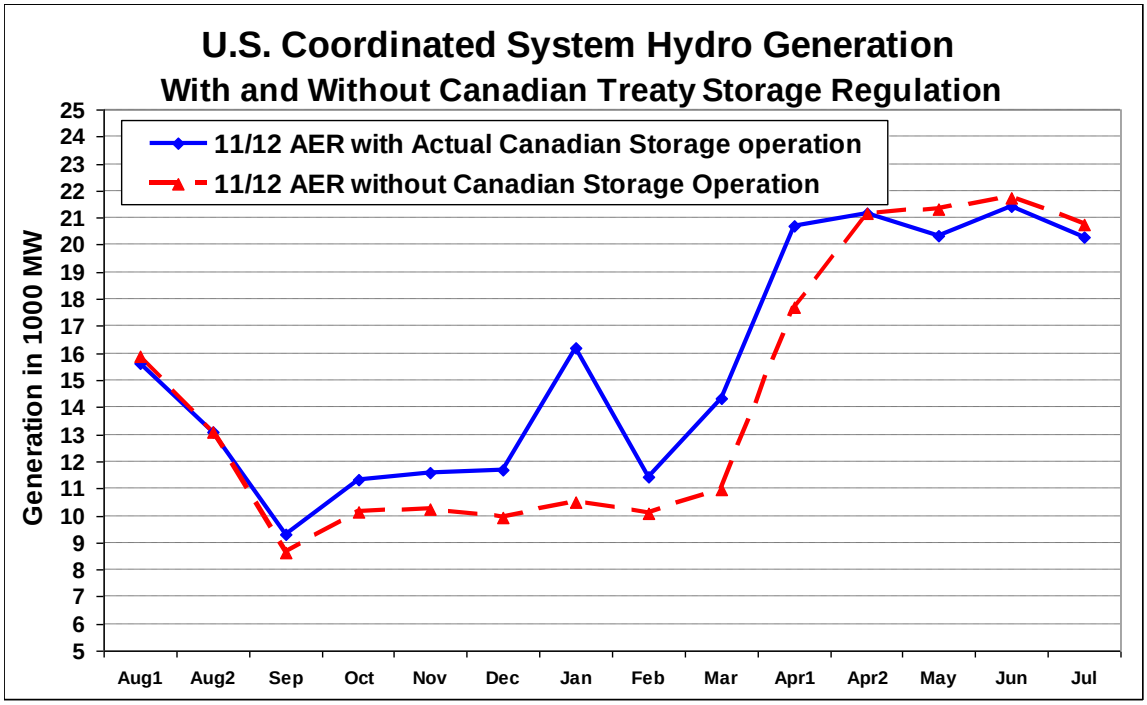
Power Generation and Other Accomplishments

Actual U.S. power benefits from the operation of Canadian storage are unknown and 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, non-power requirements, loads and resources, and market conditions, thus making any benefit analysis highly speculative.

The following Figure 3 shows a rough estimate of the average monthly impact on downstream U.S. power generation during the 2011-2012 Operating Year, with and without the regulation of Canadian storage, based on the PNCA 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 1245 aMW. In addition to the increase in average annual U.S. power generation, the Treaty regulation also shifted the timing of generation from the low value freshet period, into higher value winter months. No quantification of this benefit is provided in this report.

Figure 3: U.S. Coordinated System Hydro Generation



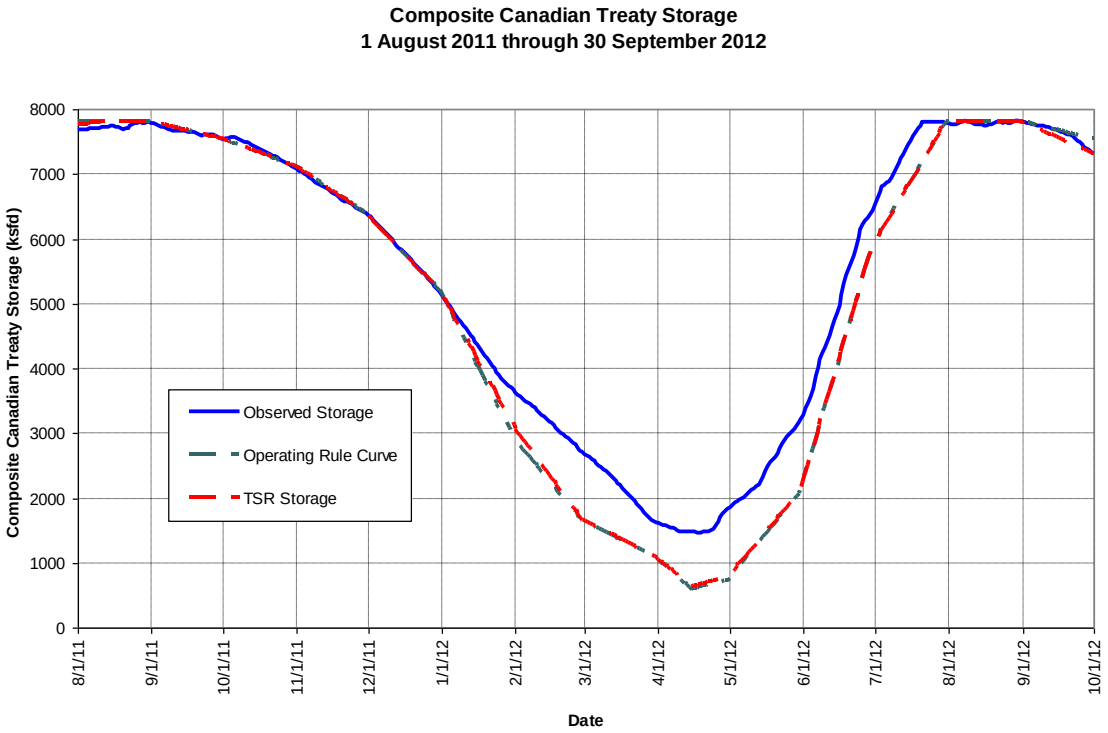
Based on the authority from the 2011-2012 and 2012-2013 DOPs, the CRTOC completed supplemental operating agreements, described in section III Operating Arrangements, which resulted in power and non-power benefits both in Canada and the U.S. Non-power benefits include changes to streamflows below Arrow that enhanced trout and mountain whitefish spawning in Canada and the downstream migration of salmon in the U.S. The benefits of these regulation improvements were not quantified in this report.

In addition, under the Libby Coordination Agreement, the U.S. received one average annual MW from B.C. Hydro. Canada received the benefits of the provisional draft operation at Arrow and related exchanges of power between B.C. Hydro and BPA, in which Arrow was drafted for two cycles this year. B.C. Hydro exercised its first draft cycle in early

September and returned the third week in September. The second draft cycle was exercised in early December, and returned in early January, and the final week in March 2012.

Figure 4 compares the actual operation of the composite Canadian storage to the results of the DOP TSR study.

Figure 4: Composite Canadian Treaty Storage



The TSR Storage Content compared to the Operating Rule Curve shows that in the TSR, Canadian projects were operated in proportional draft mode for September only during the 2011-2012 Operating Year. Comparing the Observed Storage to the TSR Storage Content shows any impacts of Supplemental Operating Agreements.

Figure 5 shows the difference in Arrow plus Duncan regulated outflows in the DOP TSR and the actual daily CRT outflows due to the agreements. The daily unregulated streamflow is also shown for comparison purposes. Note the magnitude and duration of the unregulated flows in June and July due to another above average water supply available this operating year.

Figure 5: Arrow and Duncan Treaty Flows

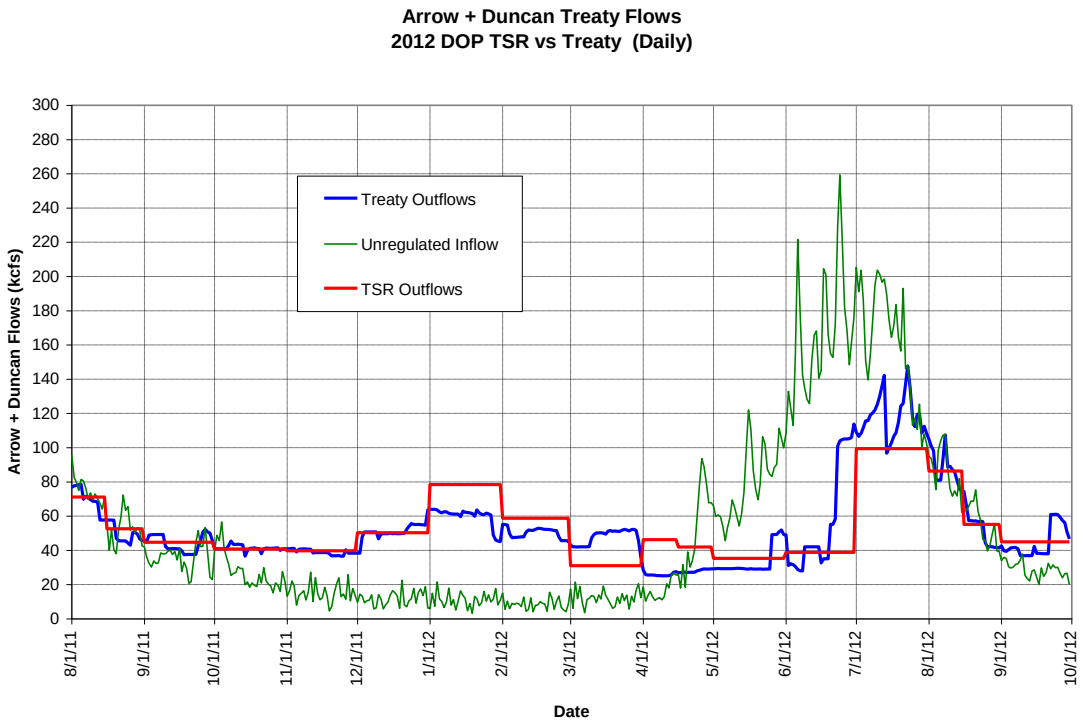


Figure 6 summarizes the Treaty accounting including supplementary operating agreements throughout the year. Section I shows the difference for each period between the final TSR composite storage and the actual Treaty composite storage, including the supplementary agreements. Section II shows the storage balance for each supplementary agreement as it was 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, thus resulting in some inadvertent storage, as shown in Section II, Line 8.

Figure 6: Summary of Treaty Storage Operation

Summary of Treaty Storage Operations
July 2011 through September 2012

All units in KSFD	2011							2012											
I. Composite Treaty Storage (	**JUL**	**AU1**	**AU2**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**AP1**	**AP2**	**MAY**	**JUN**	**JUL**	**AU1**	**AU2**	**SEP**
1)Treaty Storage Regulation (	**7752.6**	**7814.6**	**7814.4**	**7544.2**	**7127.1**	**6394.7**	**5204.0**	**3113.0**	**1661.2**	**1078.0**	**630.5**	**772.6**	**2121.1**	**5890.6**	**7814.6**	**7814.6**	**7814.4**	**7326.1**
2) Observed Treaty Content (w/SO/	7667.5	7743.6	7800.6	7546.7	7100.4	6390.5	5182.3	3666.2	2705.9	1617.3	1478.3	1828.6	3226.1	6447.1	7792.9	7758.6	7812.7	7337.7
3) % full (actual Treaty/7814.6 ksfd)	99.2%	100.0%	100.0%	96.5%	91.2%	81.8%	66.6%	39.8%	21.3%	13.8%	8.1%	9.9%	27.1%	75.4%	100.0%	100.0%	100.0%	93.7%
4) Final deviation from TSR	**-85.1**	**-71.0**	**-13.8**	**2.5**	**-26.7**	**-4.2**	**-21.7**	**553.2**	**1044.7**	**539.3**	**847.8**	**1056.0**	**1105.0**	**556.5**	**-21.7**	**-56.0**	**-1.7**	**11.6**

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

	2011							2012										
Balance in each period	**JUL**	**AU1**	**AU2**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**AP1**	**AP2**	**MAY**	**JUN**	**JUL**	**AU1**	**AU2**	**SEP**
5) Libby Coord Agreement (LCA)	0.0	0.0	0.0	0.0	0.0	0.0	-56.0	-28.0	-28.0	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	16.0	504.0	504.0	504.0	504.0	504.0	504.0	489.0	0.0	0.0	0.0	0.0
7) Total	0.0	0.0	0.0	0.0	0.0	0.0	-40.0	476.0	476.0	504.0	504.0	504.0	504.0	489.0	0.0	0.0	0.0	0.0
8. Inadvertent (Line 4 - Line	**-85.1**	**-71.0**	**-13.8**	**2.5**	**-26.7**	**-4.2**	**18.3**	**77.2**	**568.7**	**35.3**	**343.8**	**552.0**	**601.0**	**67.5**	**-21.7**	**-56.0**	**-1.7**	**11.6**
									(NPU avg Feb-| (NPU Shaping; inadvertent does not apply.)									

III. Summary of TSR Results August 2011-July 2012 (Final TSR in red)
Composite Treaty Storage TSR Content (ksfd)

	2011							2012											
TSR Date	**JUL**	**AU1**	**AU2**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**AP1**	**AP2**	**MAY**	**JUN**	**JUL**	**AU1**	**AU2**	**SEP**
8-Aug-11	**7752.6**	7814.6	7814.4	7544.2	7127.1	6394.7	5204.0	3069.5	1781.3	1183.1	965.3	1056.4	2954.4	6001.3	7752.6			
25-Aug-11		**7814.6**	7814.4	7544.2	7127.1	6394.7	5204.0	3069.5	1781.3	1185.5	965.3	1056.4	2954.4	6001.3	7752.6			
9-Sep-11			**7814.4**	7544.2	7127.1	6394.7	5204.0	3069.5	1781.3	1431.5	1383.4	1474.4	3372.5	6419.4	7752.6			
26-Sep-11				7544.2	7127.1	6394.7	5204.0	3069.5	1781.3	1353.8	1130.3	1221.4	3119.4	6166.4	7752.6			
6-Oct-11				**7544.2**	7127.1	6394.7	5204.0	3069.5	1781.3	1393.2	1169.7	1260.8	3158.8	6205.7	7752.6			
20-Oct-11					7127.1	6394.7	5204.0	3069.5	1781.3	1416.7	1193.2	1284.2	3182.3	6229.2	7752.6			
7-Nov-11					**7127.1**	6394.7	5204.0	3069.5	1781.3	1396.5	1173.0	1264.0	3162.1	6209.0	7752.6			
17-Nov-11						6394.7	5204.0	3091.4	1781.3	1382.9	1159.4	1250.4	3148.5	6195.4	7752.6			
9-Dec-11						**6394.7**	5204.1	3075.7	1391.4	941.1	946.8	1111.0	3117.4	6175.9	7752.6			
21-Dec-11							5204.0	3041.7	1330.3	941.1	946.8	1111.0	3025.8	6084.4	7752.6			
12-Jan-12							**5204.0**	3087.8	2627.2	1556.7	1564.5	1708.4	3666.5	6361.9	7752.6			
26-Jan-12								3082.7	2638.0	1571.8	1581.9	1727.5	3682.0	6375.0	7752.6			
10-Feb-12								**3113.0**	1661.2	1303.0	1106.8	1234.0	3433.2	6335.7	7752.6			
23-Feb-12									1661.2	1315.9	1117.3	1245.1	3443.4	6340.7	7752.6			
9-Mar-12									**1661.2**	1078.0	1115.4	1383.3	3358.4	6363.4	7752.6			
26-Mar-12										1078.0	1091.9	1411.2	3381.1	6363.4	7752.6			
12-Apr-12										**1078.0**	633.0	772.6	2269.6	5917.8	7717.8			
25-Apr-12											**630.5**	772.6	2269.6	5917.8	7814.6			
10-May-12												**772.6**	2121.1	5840.9	7814.6			
25-May-12													2121.1	5840.9	7814.6			
11-Jun-12													**2121.1**	5890.6	7690.6			
25-Jun-12														5890.6	7814.6	7814.6	7814.4	
11-Jul-12														**5890.6**	7814.6	7814.6	7814.4	
26-Jul-12															7814.6	7814.6	7814.4	7544.2
8-Aug-12															**7814.6**	7814.6	7814.4	7544.2
23-Aug-12																**7814.6**	7814.4	7544.2
6-Sep-12																	**7814.4**	7507.7
24-Sep-12																		7295.0
5-Oct-12																		**7326.1**
Proportional Draft Point (PDP)	1.000	1.000	1.000	1.000	1.000	1.000	1.067	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	2.351

VII – TABLES

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

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

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.45	27.87	14.48	6.70	95.47
February	2.52	29.79	15.07	7.05	104.17
March	2.48	29.60	14.91	6.95	111.76
April	2.64	30.99	15.92	8.48	127.94
May	2.75	31.89	16.18	8.83	136.62
June	2.82	31.12	15.68	8.93	135.20
Actual	3.17	35.02	17.80	11.33	146.94

Table 1: Unregulated Runoff Volume Forecasts Million Acre-feet

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

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	1.99	22.60	11.74	5.43	77.40
February	2.04	24.15	12.21	5.71	84.45
March	2.01	24.00	12.08	5.64	90.60
April	2.14	25.12	12.91	6.87	103.73
May	2.23	25.85	13.12	7.16	110.76
June	2.29	25.23	12.71	7.24	109.61
Actual	2.57	28.39	14.43	9.19	119.13

Table 2M (metric): 2012 Mica Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			12.1	12.5	12.1	12.5	11.9	9.3
PROBABLE DATE-31JULY INFLOW, hm3	**		12120.0	12488.4	12078.4	12528.5	11903.2	9284.8
95% FORECAST ERROR FOR DATE, hm3			1802.7	1276.7	1113.6	1028.0	982.2	971.2
95% CONF.DATE-31JULY INFLOW, hm3	1/		10317.3	11211.8	10964.8	11500.6	10921.0	8313.6
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		10317.3					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		5531.0					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		3848.3					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		739.9					
JAN31 ORC, m	7/		740.5					
BASE ECC, m	8/	740.5						
LOWER LIMIT, m		731.9						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		10110.9	10987.5				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		5318.1	4811.6				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		3841.8	2458.6				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		739.8	736.8				
FEB28 ORC, m	7/		740.2	737.0				
BASE ECC, m	8/	740.2						
LOWER LIMIT, m		729.9						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		9863.3	10718.5	10701.6			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0			
MIN APR1-JUL31 OUTFLOW, hm3	4/		5090.6	4584.0	4218.7			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		3861.9	2500.1	2151.6			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		739.8	736.9	737.3			
MAR31 ORC, m	7/		740.3	737.1	736.1			
BASE ECC, m	8/	740.3						
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/		9357.7	10169.1	10142.4	10902.6		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		4870.4	4363.8	3998.5	3998.5		
VRC APR30 RESERVOIR CONTENT, hm3	5/		4147.2	2829.3	2490.6	1730.5		
VRC APR30 RESERVOIR CONTENT, METERS	6/		740.4	737.6	738.1	737.8		
APR30 ORC, m	7/		740.9	738.1	737.1	734.9		
BASE ECC, m	8/	740.8						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		7407.8	8050.1	8026.2	8625.4	8638.5	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0	85.0	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		4642.9	4136.3	3770.9	3770.9	3770.9	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		5869.6	4720.8	4379.3	3780.0	3766.9	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		744.4	742.3	742.7	742.4	742.1	
MAY31 ORC, m	7/		745.8	743.2	742.3	740.7	740.6	
BASE ECC, m	8/	745.8						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		3755.5	4081.1	4057.0	4358.7	4368.4	4206.7
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		509.7	746.5	608.9	509.7	509.7	509.7
MIN JUL1-JUL31 OUTFLOW, hm3	4/		2708.0	2558.0	2449.8	2449.8	2449.8	2449.8
VRC JUN30 RESERVOIR CONTENT, hm3	5/		7587.0	7111.4	7027.3	6725.6	6715.9	6877.6
VRC JUN30 RESERVOIR CONTENT, METERS	6/		749.2	748.2	748.4	748.3	748.1	747.8
JUN30 ORC, m	7/		750.4	749.2	749.0	748.3	748.2	748.6
BASE ECC, m	8/	752.6						
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 FLOOD CONTROL.

Table 2: 2012 Mica Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			9825.7	10124.4	9792.0	10157.0	9650.0	7527.3
PROBABLE DATE-31JULY INFLOW, KSFD	**		4953.8	5104.4	4936.8	5120.8	4865.2	3795.0
95% FORECAST ERROR FOR DATE, KSFD			736.8	521.8	455.2	420.2	401.4	397.0
95% CONF.DATE-31JULY INFLOW, KSFD	1/		4217.0	4582.6	4481.6	4700.6	4463.8	3398.0
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		4217.0					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		2260.7					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1572.9					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2427.4					
JAN31 ORC, FT	7/		2429.6					
BASE ECC, FT	8/	2429.6						
LOWER LIMIT, FT		2401.1						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		4132.6	4490.9				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		2173.7	1966.6				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1570.3	1004.9				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2427.2	2417.3				
FEB28 ORC, FT	7/		2428.6	2418.0				
BASE ECC, FT	8/	2428.6						
LOWER LIMIT, FT		2394.8						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		4031.4	4381.0	4374.1			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		2080.7	1873.6	1724.3			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1578.5	1021.9	879.4			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2427.1	2417.5	2419.1			
MAR31 ORC, FT	7/		2428.7	2418.4	2415.2			
BASE ECC, FT	8/	2428.7						
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/		3824.8	4156.4	4145.5	4456.2		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1990.7	1783.6	1634.3	1634.3		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1695.1	1156.4	1018.0	707.3		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2429.2	2420.1	2421.7	2420.5		
APR30 ORC, FT	7/		2430.6	2421.4	2418.3	2411.2		
BASE ECC, FT	8/	2430.6						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		3027.8	3290.3	3280.6	3525.5	3530.8	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0	3000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		1897.7	1690.6	1541.3	1541.3	1541.3	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2399.1	1929.5	1789.9	1545.0	1539.7	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2442.2	2435.4	2436.7	2435.8	2434.6	
MAY31 ORC, FT	7/		2446.7	2438.2	2435.2	2430.0	2429.9	
BASE ECC, FT	8/	2447.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1535.0	1668.1	1658.2	1781.5	1785.5	1719.4
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		18000.0	26361.7	21503.7	18000.0	18000.0	18000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		1106.8	1045.5	1001.3	1001.3	1001.3	1001.3
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3101.1	2906.7	2872.3	2749.0	2745.0	2811.1
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2458.1	2454.9	2455.5	2455.1	2454.5	2453.4
JUN30 ORC, FT	7/		2461.9	2458.1	2457.4	2454.9	2454.9	2456.2
BASE ECC, FT	8/	2469.2						
JUL 31 ORC, FT			2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

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

Table 3M (metric): 2012 Arrow Reservoir 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			24.6	25.9	25.1	25.5	24.0	17.9
& IN hm3	**		24575.4	25875.5	25127.8	25495.3	24005.3	17910.1
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/		20948.2					
MIN FEB1-JUL31 OUTFLOW, hm3	3/		10529.1					
UPSTREAM DISCHARGE, hm3	4/		4899.1					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		3237.9					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		422.6					
JAN31 ORC, m	7/		428.5					
BASE ECC, m	8/	429.6						
LOWER LIMIT, m		421.1						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		20466.3	22662.3				
MIN MAR1-JUL31 OUTFLOW, hm3	3/		10174.4	9262.4				
UPSTREAM DISCHARGE, hm3	4/		5012.3	6176.0				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		3478.2	1533.9				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		423.2	420.0				
FEB28 ORC, m	7/		429.1	424.3				
BASE ECC, m	8/	429.9						
LOWER LIMIT, m		420.2						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		19858.8	21989.7	22132.2			
MIN APR1-JUL31 OUTFLOW, hm3	3/		9795.2	8883.2	7313.5			
UPSTREAM DISCHARGE, hm3	4/		4995.7	6134.4	6483.0			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		3689.9	1785.8	422.2			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		423.7	420.1	420.1			
MAR31 ORC, m	7/		429.6	425.0	421.3			
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/		18413.4	20389.1	20536.7	21821.2		
MIN MAY1-JUL31 OUTFLOW, hm3	3/		9428.2	8516.2	6946.6	4257.8		
UPSTREAM DISCHARGE, hm3	4/		4779.9	5805.2	6144.0	6904.1		
VRC APR30 RESERVOIR CONTENT, hm3	5/		4552.5	2690.2	1311.7	0.0		
VRC APR30 RESERVOIR CONTENT, METERS	6/		425.6	420.0	420.0	420.0		
APR30 ORC, Fm	7/		431.5	427.2	423.7	420.0		
BASE ECC, m	8/	431.7						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		13679.1	15146.9	15248.6	16201.3	16521.3	
MIN JUN1-JUL31 OUTFLOW, hm3	3/		9049.0	8137.0	6567.3	3878.6	3878.6	
UPSTREAM DISCHARGE, hm3	4/		2906.1	3913.7	4255.3	4854.5	4867.6	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		7033.8	5661.7	4331.8	1289.6	982.7	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		431.3	426.0	426.1	426.0	426.0	
MAY31 ORC, m	7/		434.7	433.9	431.1	423.7	422.9	
BASE ECC, m	8/	437.8						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		6389.2	7074.7	7134.3	7571.6	7738.1	7604.1
MIN JUL1-JUL31 OUTFLOW, hm3	3/		4875.8	4554.7	4117.6	3511.6	3511.6	3511.6
UPSTREAM DISCHARGE, hm3	4/		1047.5	1523.1	1607.2	1908.9	1918.6	1756.9
VRC JUN30 RESERVOIR CONTENT, hm3	5/		8292.0	7760.9	7348.4	6606.8	6450.0	6422.3
VRC JUN30 RESERVOIR CONTENT, METERS	6/		438.3	436.4	436.5	435.9	435.9	435.9
JUN30 ORC, m	7/		439.2	438.2	437.4	435.9	435.6	435.5
BASE ECC, m	8/	440.1						
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 FLOOD CONTROL.

Table 3: 2012 Arrow Reservoir 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			19923.4	20977.4	20371.2	20669.1	19461.2	14519.8
& IN KSFD	**		10044.7	10576.1	10270.5	10420.7	9811.7	7320.4
95% FORECAST ERROR FOR DATE, IN KSFD			1482.1	1095.5	953.7	810.2	722.5	678.6
95% CONF.DATE-31JULY INFLOW, KSFD	1/		7937.9	8989.5	8689.3	8789.8	8482.5	6453.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		8562.1					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		4303.6					
UPSTREAM DISCHARGE, KSFD	4/		2002.4					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1323.4					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1386.5					
JAN31 ORC, FT	7/		1406.0					
BASE ECC, FT	8/	1409.4						
LOWER LIMIT, FT		1381.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		8365.2	9262.8				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		4158.6	3785.8				
UPSTREAM DISCHARGE, KSFD	4/		2048.7	2524.3				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1421.7	627.0				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1388.5	1377.9				
FEB28 ORC, FT	7/		1407.8	1392.2				
BASE ECC, FT	8/	1410.3						
LOWER LIMIT, FT		1378.6						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		8116.9	8987.8	9046.1			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		4003.6	3630.8	2989.3			
UPSTREAM DISCHARGE, KSFD	4/		2041.9	2507.3	2649.8			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1508.2	729.9	172.6			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1390.0	1378.3	1378.3			
MAR31 ORC, FT	7/	1411.8	1409.4	1394.3	1382.1			
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/		7526.1	8333.7	8394.0	8919.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		3853.6	3480.8	2839.3	1740.3		
UPSTREAM DISCHARGE, KSFD	4/		1953.7	2372.8	2511.2	2821.9		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1860.8	1099.5	536.1	0.0		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1396.4	1378.0	1378.1	1378.0		
APR30 ORC, FT	7/		1415.8	1401.7	1390.3	1377.9		
BASE ECC, FT	8/	1416.3						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		5591.1	6191.0	6232.6	6622.0	6752.8	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		3698.6	3325.8	2684.3	1585.3	1585.3	
UPSTREAM DISCHARGE, KSFD	4/		1187.8	1599.7	1739.3	1984.2	1989.5	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2874.9	2314.1	1770.5	527.1	401.7	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1415.1	1397.7	1398.1	1397.7	1397.7	
MAY31 ORC, FT	7/		1426.2	1423.6	1414.2	1390.1	1387.3	
BASE ECC, FT	8/	1436.5						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		2611.5	2891.7	2916.0	3094.7	3162.8	3108.0
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		1992.9	1861.7	1683.0	1435.3	1435.3	1435.3
UPSTREAM DISCHARGE, KSFD	4/		428.1	622.5	656.9	780.2	784.2	718.1
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3389.2	3172.1	3003.5	2700.4	2636.3	2625.0
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1438.0	1431.8	1432.2	1430.2	1430.2	1430.2
JUN30 ORC, FT	7/		1441.1	1437.7	1435.0	1430.1	1429.1	1428.9
BASE ECC, FT	8/	1444.0						
JUL 31 ECC, FT			1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

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

Table 4M (metric): 2012 Duncan Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			2.1	2.2	2.1	2.2	2.1	1.6
& IN hm3	**		2124.9	2173.3	2104.8	2160.6	2081.1	1623.6
95% FORECAST ERROR FOR DATE, IN hm3			309.0	255.2	256.8	229.5	212.6	190.8
95% CONF.DATE-31JULY INFLOW, hm3	1/		1815.9	1918.1	1848.0	1931.1	1868.4	1432.8
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		1815.9					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		300.3					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		211.2					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		551.9					
JAN31 ORC, m	7/		552.1					
BASE ECC, m	8/	564.0						
LOWER LIMIT, m		551.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.1	98.1				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		1781.4	1881.7				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		293.2	210.0				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		238.6	55.1				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		552.4	549.2				
FEB28 ORC, m	7/		552.7	548.5				
BASE ECC, m	8/	560.0						
LOWER LIMIT, m		548.2						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.7	95.7	97.6			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		1737.8	1835.7	1803.6			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8			
MIN APR1-JUL31 OUTFLOW, hm3	4/		285.6	202.4	140.5			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		274.6	93.6	63.6			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		553.1	550.1	550.9			
MAR31 ORC, m	7/		551.4	549.5	548.7			
BASE ECC, m	8/	559.9						
LOWER LIMIT, m		546.9						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.7	89.7	91.6	93.8		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		1628.9	1720.6	1692.8	1811.4		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8	2.8		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		278.3	195.1	133.1	127.5		
VRC APR30 RESERVOIR CONTENT, hm3	5/		376.2	201.3	167.2	42.9		
VRC APR30 RESERVOIR CONTENT, METERS	6/		554.9	552.3	553.0	551.0		
APR30 ORC, m	7/		551.4	551.0	551.0	548.2		
BASE ECC, m	8/	561.0						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.5	67.5	69.0	70.6	75.3	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		1225.7	1294.7	1275.1	1363.4	1406.9	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	24.8	12.0	2.8	2.8	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		211.8	162.8	125.5	119.9	119.9	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		712.9	594.9	577.2	483.3	439.8	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		561.4	559.7	560.1	559.1	557.7	
MAY31 ORC, m	7/		561.4	559.3	559.0	557.4	556.6	
BASE ECC, m	8/	567.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			32.5	32.5	33.3	34.0	36.3	48.2
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		590.2	623.4	615.4	656.6	678.2	690.6
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		17.0	37.3	25.5	17.0	17.0	17.0
MIN JUL1-JUL31 OUTFLOW, hm3	4/		115.1	96.7	81.5	75.8	75.8	75.8
VRC JUN30 RESERVOIR CONTENT, hm3	5/		1251.8	1200.1	1192.9	1146.1	1124.4	1112.0
VRC JUN30 RESERVOIR CONTENT, METERS	6/		569.9	569.2	569.4	568.9	568.4	568.2
JUN30 ORC, m	7/		569.8	569.1	568.9	568.2	567.9	567.7
BASE ECC, m	8/	571.4						
JUL 31 ECC, m			576.7	576.7	576.7	576.7	576.7	576.7

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

Table 4: 2012 Duncan Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			1722.6	1761.9	1706.4	1751.6	1687.1	1316.2
& IN KSFD	**		868.5	888.3	860.3	883.1	850.6	663.6
95% FORECAST ERROR FOR DATE, IN KSFD			126.3	104.3	105.0	93.8	86.9	78.0
95% CONF.DATE-31JULY INFLOW, KSFD	1/		742.2	784.0	755.3	789.3	763.7	585.6
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		742.2					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		122.7					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		86.3					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1810.6					
JAN31 ORC, FT	7/		1811.4					
BASE ECC, FT	8/	1850.4						
LOWER LIMIT, FT		1810.0						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.1	98.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		728.1	769.1				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		119.8	85.8				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		97.5	22.5				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1812.3	1801.8				
FEB28 ORC, FT	7/		1813.3	1799.5				
BASE ECC, FT	8/	1837.4						
LOWER LIMIT, FT		1798.7						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.7	95.7	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		710.3	750.3	737.2			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		116.7	82.7	57.4			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		112.2	38.2	26.0			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1814.5	1804.7	1807.3			
MAR31 ORC, FT	7/		1808.9	1802.7	1800.2			
BASE ECC, FT	8/	1837.0						
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/		665.8	703.2	691.9	740.4		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0	100.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		113.7	79.7	54.4	52.1		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		153.8	82.3	68.3	17.5		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1820.5	1812.0	1814.1	1807.9		
APR30 ORC, FT	7/		1808.9	1807.8	1807.8	1798.4		
BASE ECC, FT	8/	1840.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.5	67.5	69.0	70.6	75.3	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		501.0	529.2	521.2	557.3	575.1	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	876.4	425.3	100.0	100.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		86.6	66.5	51.3	49.0	49.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		291.4	243.1	235.9	197.5	179.7	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1841.9	1836.4	1837.7	1834.3	1829.7	
MAY31 ORC, FT	7/		1841.7	1835.1	1834.1	1828.7	1826.1	
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/		241.2	254.8	251.5	268.4	277.2	282.3
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		600.0	1316.7	900.3	600.0	600.0	600.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		47.1	39.5	33.3	31.0	31.0	31.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		511.6	490.5	487.6	468.4	459.6	454.5
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1869.9	1867.5	1868.0	1866.6	1864.7	1864.0
JUN30 ORC, FT	7/		1869.5	1867.0	1866.6	1864.3	1863.2	1862.6
BASE ECC, FT	8/	1874.7						
JUL 31 ECC, FT			1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

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

Table 5M (metric): 2012 Libby Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			6.8	7.1	6.9	8.4	8.7	8.8
PROBABLE DATE-31JULY INFLOW, hm3			6826.3	7103.7	6940.8	8382.8	8701.1	8796.0
95% FORECAST ERROR FOR DATE, hm3			1909.3	1282.8	1174.4	1034.7	935.3	819.1
OBSERVED JAN1-DATE INFLOW, IN hm3			0.0	206.0	387.3	664.7	1648.0	4021.2
95% CONF.DATE-31JULY INFLOW, hm3	1/		4916.9	5614.9	5379.1	6683.1	6117.7	3955.9
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		4764.5					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		3422.8					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		4800.5					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		742.0					
JAN31 ORC, m	7/		738.0					
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/		4626.8	5452.0				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		3139.0	3139.0				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		4654.4	3829.2				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		741.1	735.9				
FEB28 ORC, m	7/		737.3	735.9				
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/		4454.8	5249.9	5180.2			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3			
MIN APR1-JUL31 OUTFLOW, hm3	4/		2835.6	2835.6	2628.6			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		4523.0	3727.9	3590.6			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		740.3	735.2	734.3			
MAR31 ORC, m	7/		736.4	735.2	734.3			
BASE ECC, m	9/	736.4						
LOWER LIMIT, m		699.0						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.3	85.0	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		4046.4	4772.6	4706.8	6074.9		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3	113.3		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		2542.0	2542.0	2335.0	1724.9		
VRC APR30 RESERVOIR CONTENT, hm3	5/		4637.5	3911.6	3770.5	1792.1		
VRC APR30 RESERVOIR CONTENT, METERS	6/		741.0	736.4	735.5	719.2		
APR30 ORC, m	7/		736.1	736.1	735.5	719.2		
BASE ECC, m	9/	736.1						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.1	57.0	58.6	60.9	67.0	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		2709.1	3200.4	3152.2	4070.2	4098.8	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		424.8	424.8	374.5	226.5	226.5	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		2238.6	2238.6	2031.7	1421.5	1421.5	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		5671.7	5180.4	5021.6	3493.5	3464.9	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		746.9	744.2	743.3	733.6	733.4	
MAY31 ORC, m	7/		743.0	743.0	743.0	733.6	733.4	
BASE ECC, m	9/	743.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.6	20.4	20.9	21.8	23.9	35.8
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		963.7	1145.5	1124.2	1457.0	1462.1	1416.1
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		424.8	424.8	396.1	311.5	28.3	311.5
MIN JUL1-JUL31 OUTFLOW, hm3	4/		1137.7	1137.7	1060.8	834.3	834.3	834.3
VRC JUN30 RESERVOIR CONTENT, hm3	5/		6142.2	6134.4	6078.8	5519.5	5514.4	5560.4
VRC JUN30 RESERVOIR CONTENT, METERS	6/		749.5	749.5	749.2	746.1	746.1	746.3
JUN30 ORC, m	7/		749.5	749.5	749.2	746.1	746.1	746.3
BASE ECC, m	9/	743.0						
JUL 31 ORC, m			749.5	749.5	749.5	749.5	749.5	749.5
JAN1-JUL31 FORECAST,-EARLYBIRD, km3	8/		106.1	112.5	121.9	139.3	148.0	145.3

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: 2012 Libby Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE JAN-31JULY INFLOW, KAF			5534.0	5759.0	5627.0	6796.0	7054.0	7131.0
PROBABLE JAN-31JULY INFLOW, KSFD			2790.1	2903.5	2836.9	3426.3	3556.4	3595.2
95% FORECAST ERROR FOR DATE, KSFD			780.4	524.3	480.0	422.9	382.3	334.8
OBSERVED JAN1-DATE INFLOW, IN KSFD			0.0	84.2	158.3	271.7	673.6	1643.6
95% CONF.DATE-31JULY INFLOW, KSFD	1/		2009.7	2295.0	2198.6	2731.6	2500.5	1616.9
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		1947.4					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1399.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1962.1					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2434.3					
JAN31 ORC, FT	7/		2421.4					
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/		1891.1	2228.4				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1283.0	1283.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1902.4	1565.1				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2431.4	2414.3				
FEB28 ORC, FT	7/		2418.8	2414.3				
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/		1820.8	2145.8	2117.3			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0	4000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1159.0	1159.0	1074.4			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1848.7	1523.7	1467.6			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2428.8	2412.1	2409.1			
MAR31 ORC, FT	7/		2416.0	2412.1	2409.1			
BASE ECC, FT	9/	2416.0						
LOWER LIMIT, FT		2293.4						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.3	85.0	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		1653.9	1950.7	1923.8	2483.0		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0	4000.0	4000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1039.0	1039.0	954.4	705.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1895.5	1598.8	1541.1	732.5		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2431.1	2416.1	2413.0	2359.6		
APR30 ORC, FT	7/		2415.1	2415.1	2413.0	2359.6		
BASE ECC, FT	9/	2415.1						
		2287.0						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.1	57.0	58.6	60.9	67.0	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		1107.3	1308.1	1288.4	1663.6	1675.3	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		15000.0	15000.0	13226.7	8000.0	8000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		915.0	915.0	830.4	581.0	581.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2318.2	2117.4	2052.5	1427.9	1416.2	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2450.6	2441.6	2438.6	2406.8	2406.1	
MAY31 ORC, FT	7/		2437.6	2437.6	2437.6	2406.8	2406.1	
BASE ECC, FT	9/	2437.6						
		2287.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.6	20.4	20.9	21.8	23.9	35.8
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		393.9	468.2	459.5	595.5	597.6	578.8
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		15000.0	15000.0	13986.7	11000.0	1000.0	11000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		465.0	465.0	433.6	341.0	341.0	341.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2510.5	2507.3	2484.6	2256.0	2253.9	2272.7
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2459.0	2458.9	2457.9	2447.9	2447.8	2448.6
JUN30 ORC, FT	7/		2459.0	2458.9	2457.9	2447.9	2447.8	2448.6
BASE ECC, FT	9/	2437.6						
		2287.0						
JUL 31 ORC, FT			2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		86.0	91.2	98.8	112.9	120.0	117.8

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 6: Computation of Initial Controlled Flow

Columbia River at The Dalles, OR

Metric and English Units, based 1 April 2012 forecast

Upstream Storage Corrections	Metric (km^3)	English (Maf)
Mica	9.922	8.044
Arrow	4.441	3.600
Duncan	1.698	1.376
Libby	3.773	3.058
Hungry Horse	1.032	0.836
Flathead Lake	0.617	0.500
Noxon Rapids	0.000	0.000
Pend Oreille Lake	0.617	0.500
Grand Coulee	5.676	4.602
Brownlee	0.848	0.687
Dworshak	1.824	1.479
John Day	0.195	0.158
Total Upstream Storage Corrections	30.641	24.841

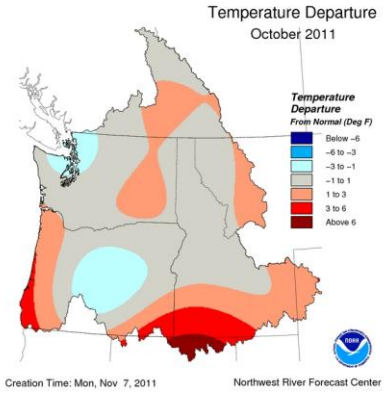
Adjusted TDA May-Aug Runoff Volume	Metric (km^3)	English (Maf)
TDA May-Aug Runoff Volume (1May Forecast)	108.462	87.931
Less Estimated Depletions	-2.061	-1.671
Less Total Upstream Storage Corrections	-30.641	-24.841
Adjusted TDA May-Aug Runoff Volume	75.759	61.419

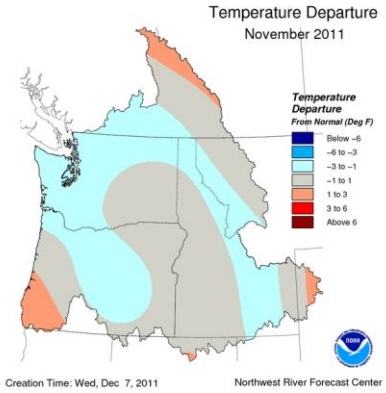
Initial Controlled Flow	m^3/s	kcfs
Determined using 'Adjusted TDA May-Aug Runoff Volume' and Chart 1 of the Flood Control Operating Plan	**11100**	**392.8**

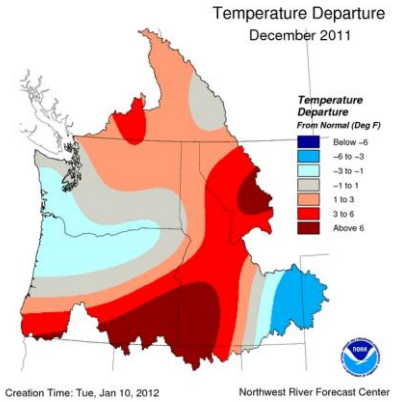
VIII - CHARTS

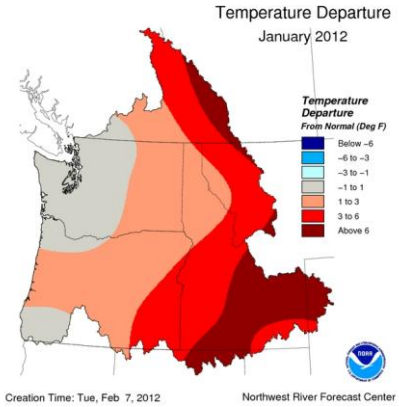
Chart 1: Pacific Northwest Monthly Temperature Departures

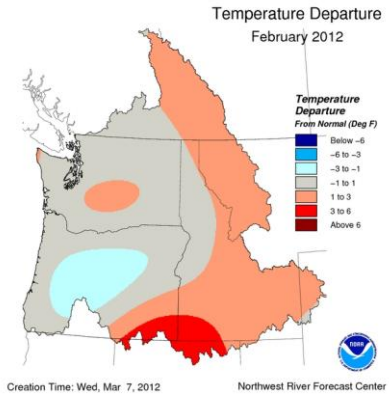
October – March











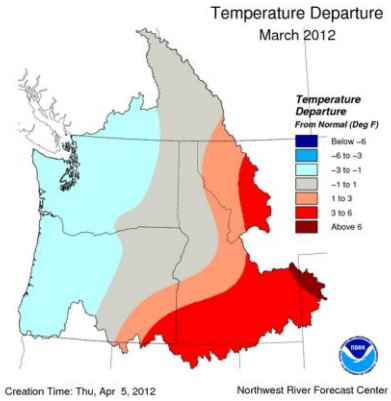
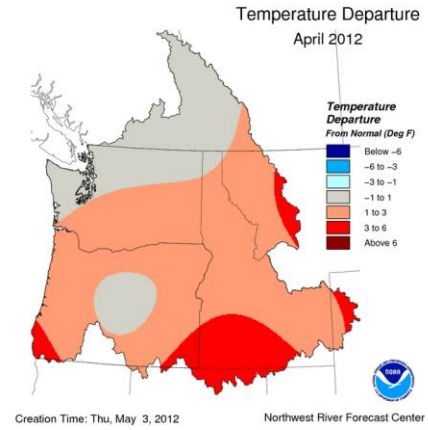
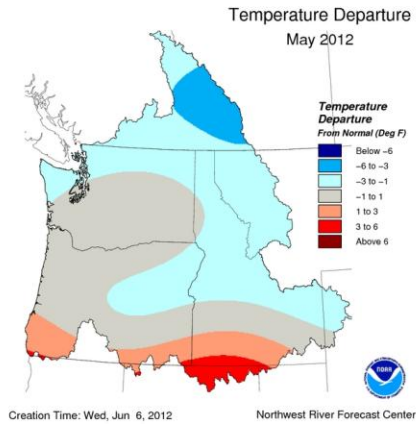
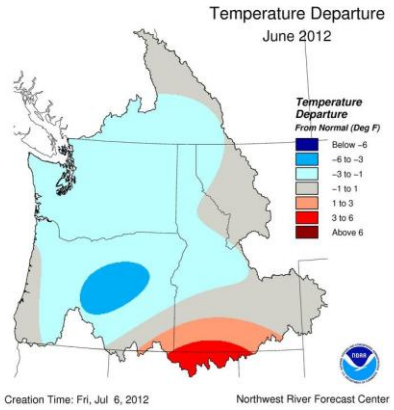
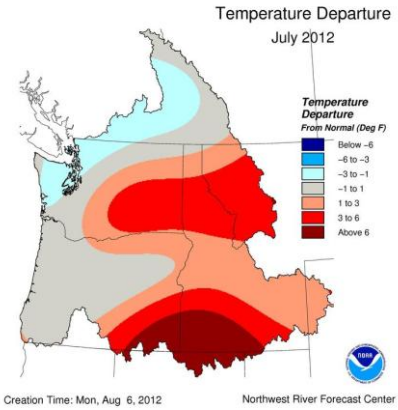


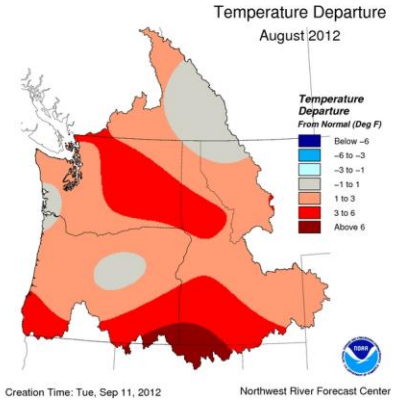
Chart 1: Pacific Northwest Monthly Temperature Departures (Continued)
April – September











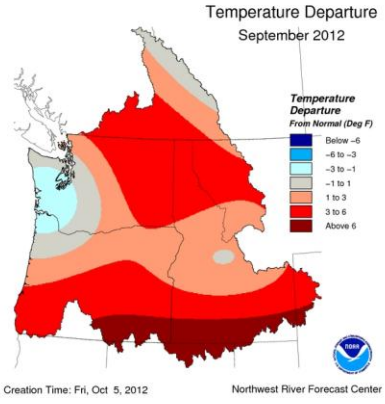


Chart 2: Seasonal Precipitation Columbia River Basin

October 2011 – September 2012

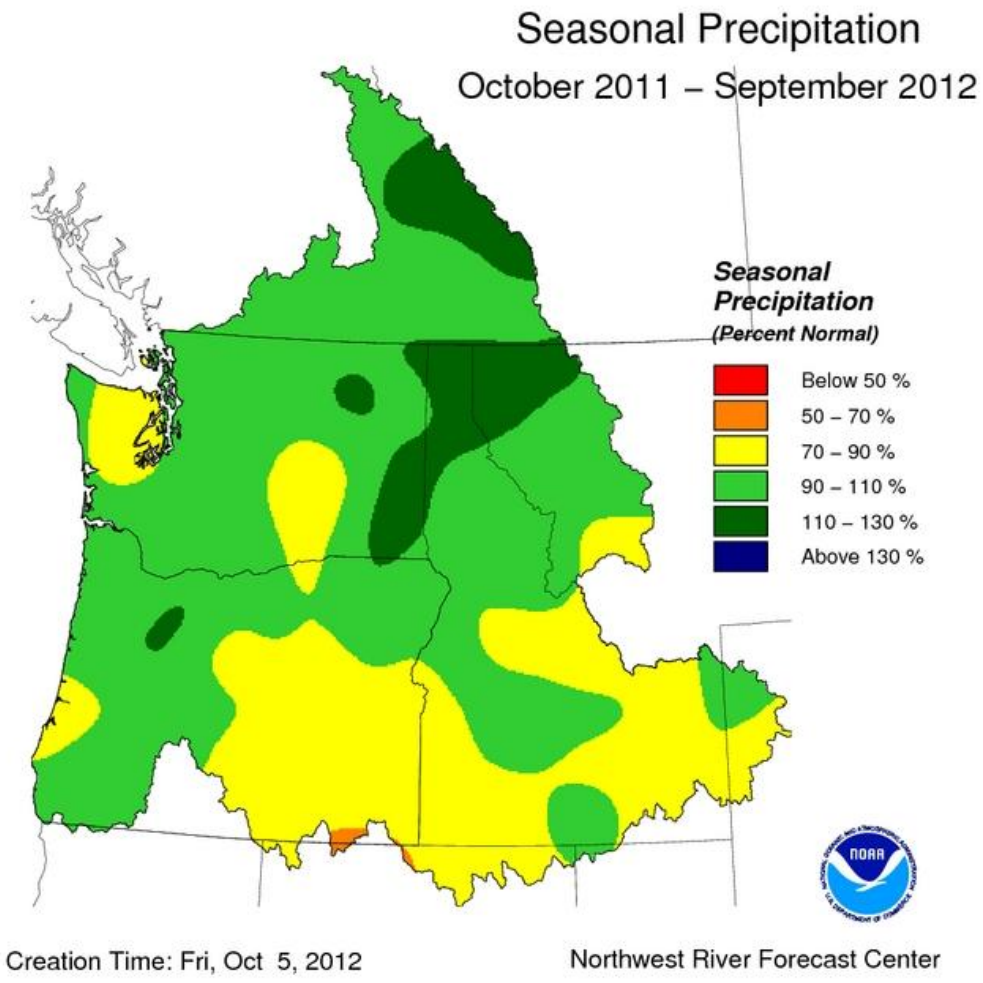
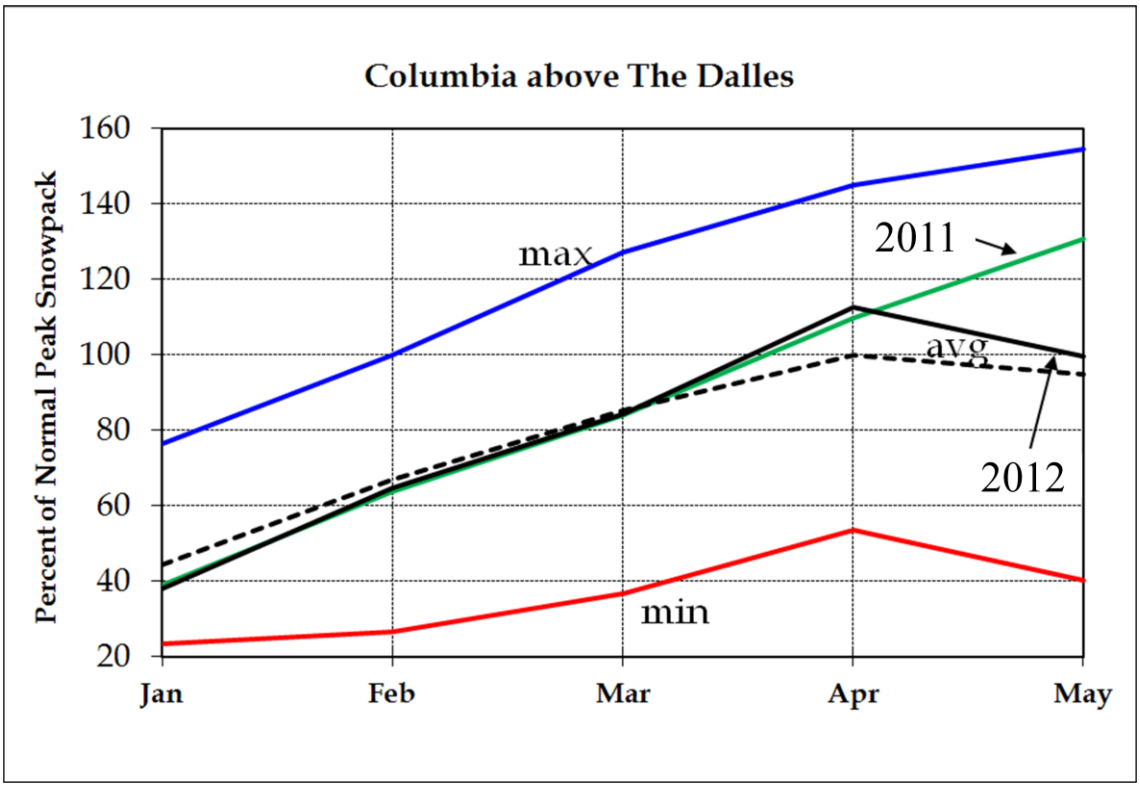


Chart 3: Columbia Basin Snowpack



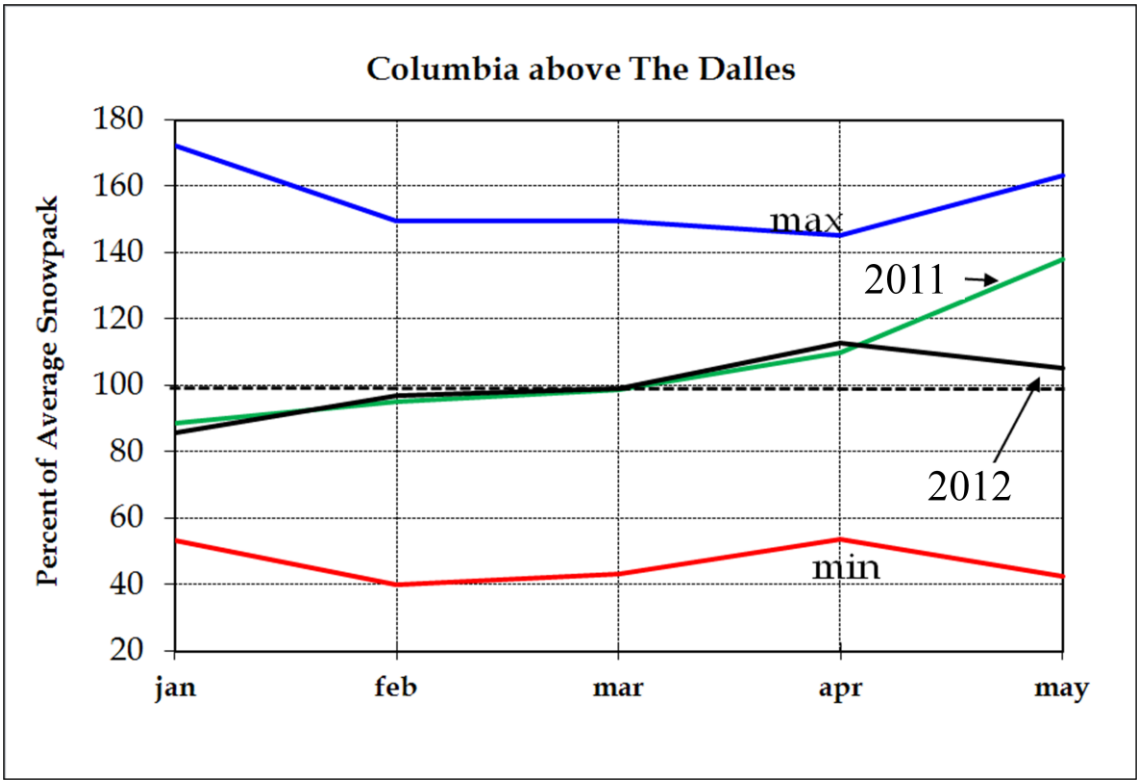


Chart 4: Accumulated Precipitation for WY 2012

At Primary Columbia River Basins

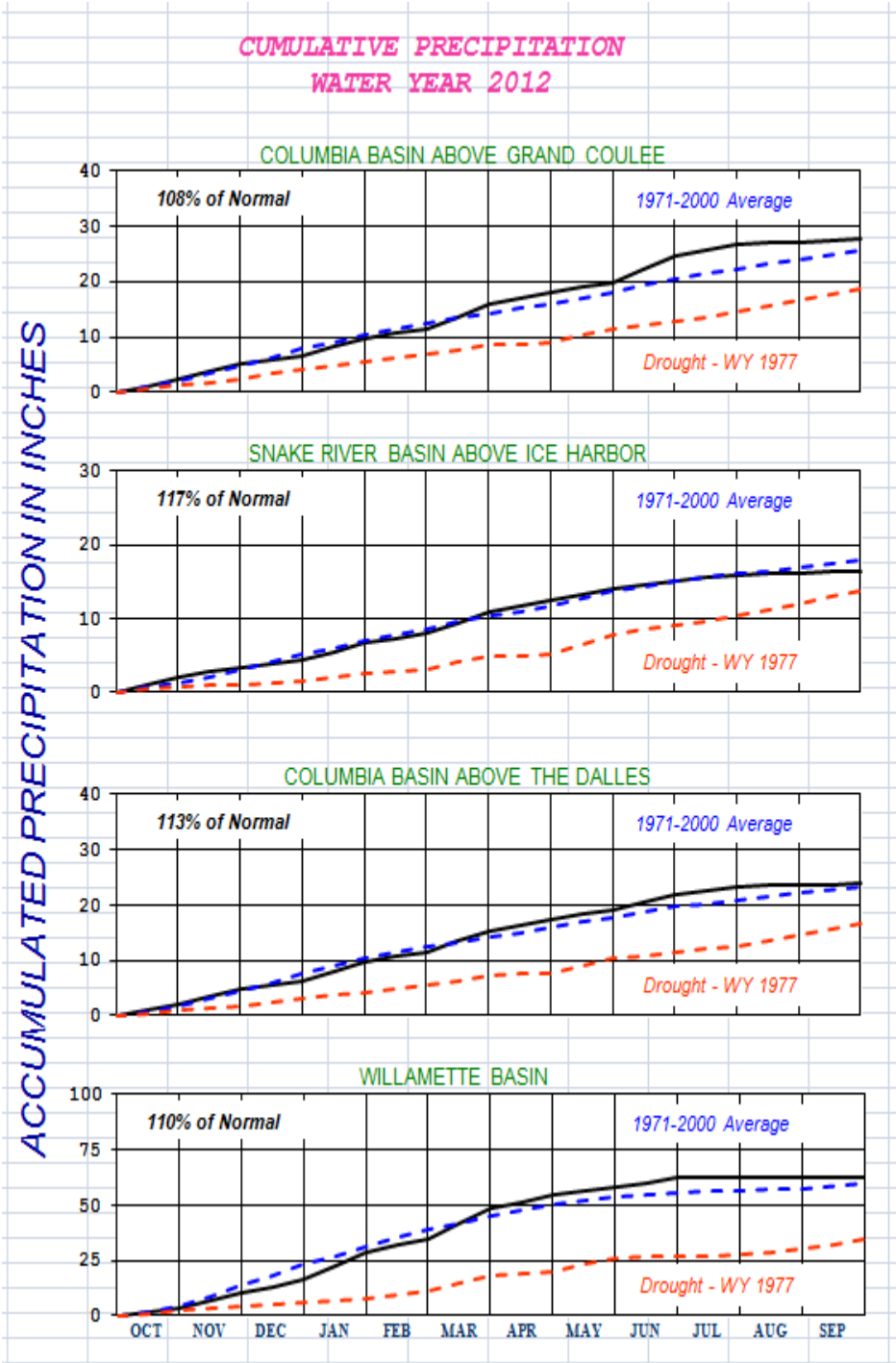


Chart 5: Regulation of Mica

1 July 2011 – 30 September 2012

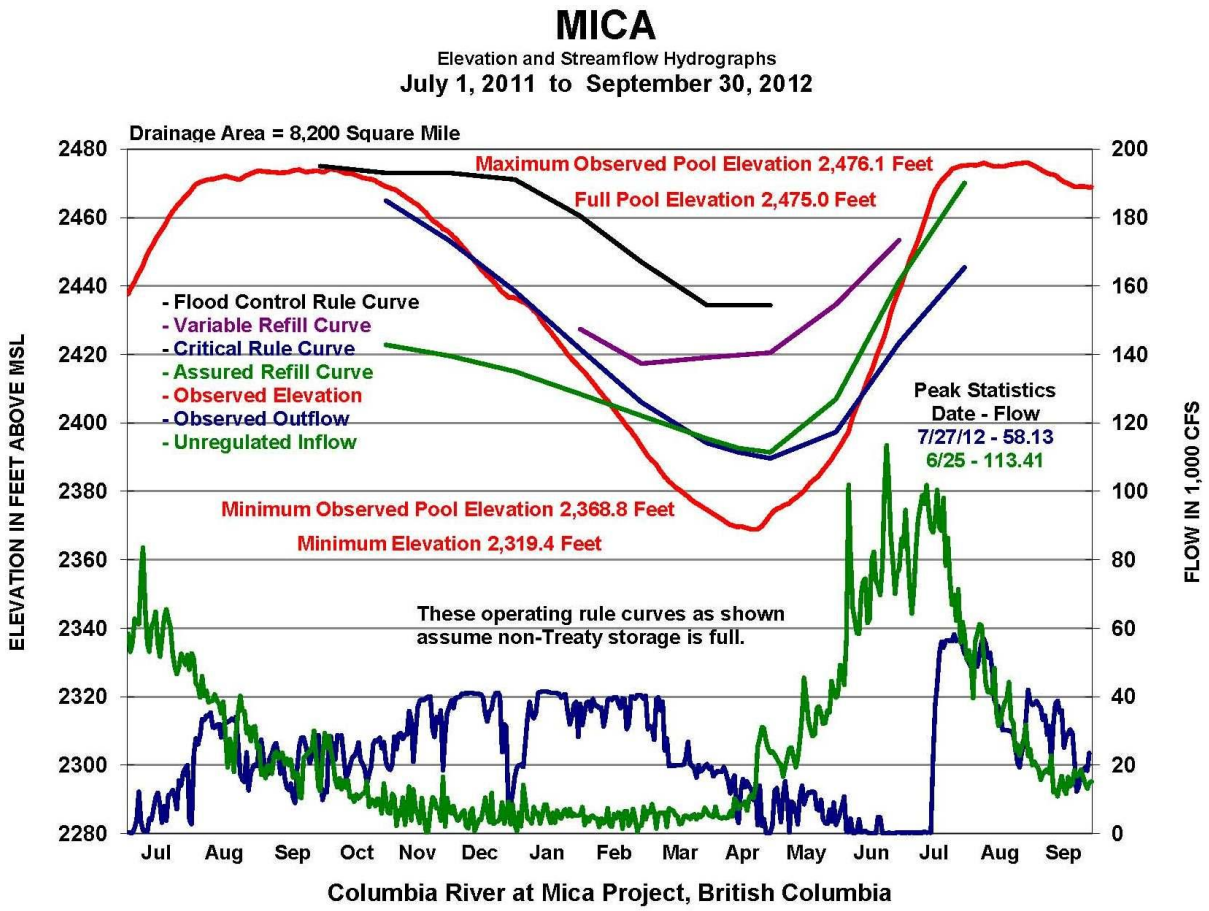


Chart 6: Regulation of Arrow

1 July 2011 – 30 September 2012

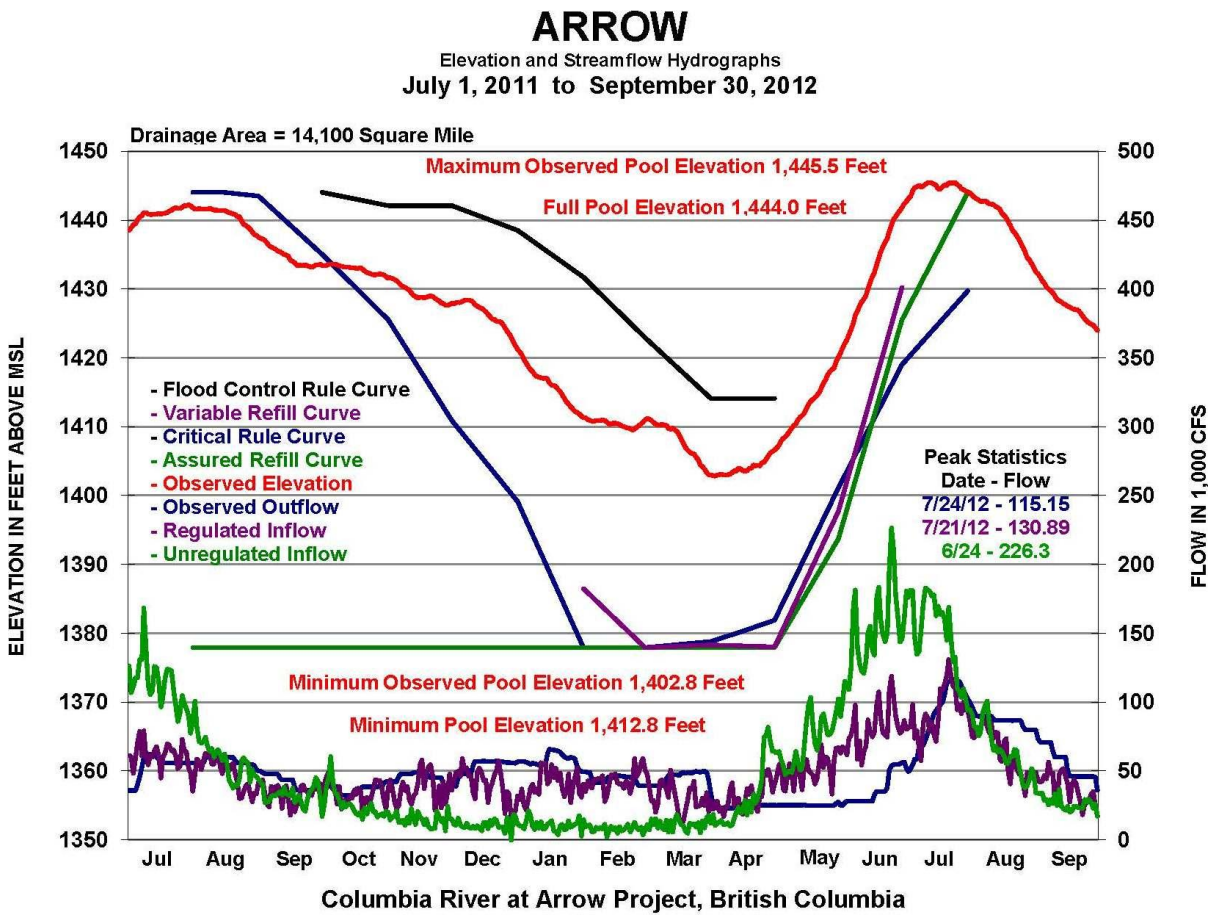


Chart 7: Regulation of Duncan

1 July 2011 – 30 September 2012

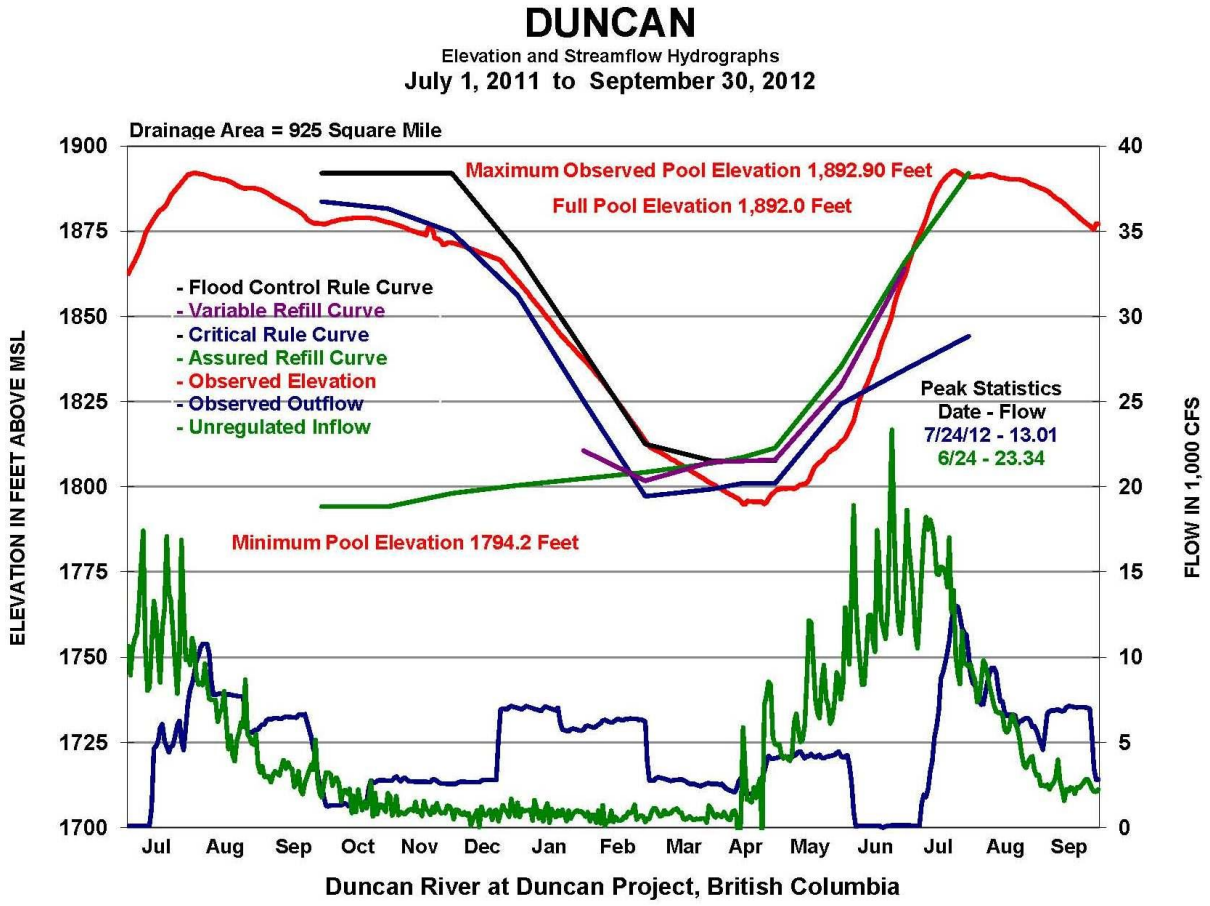


Chart 8: Regulation of Libby

1 July 2011 – 30 September 2012

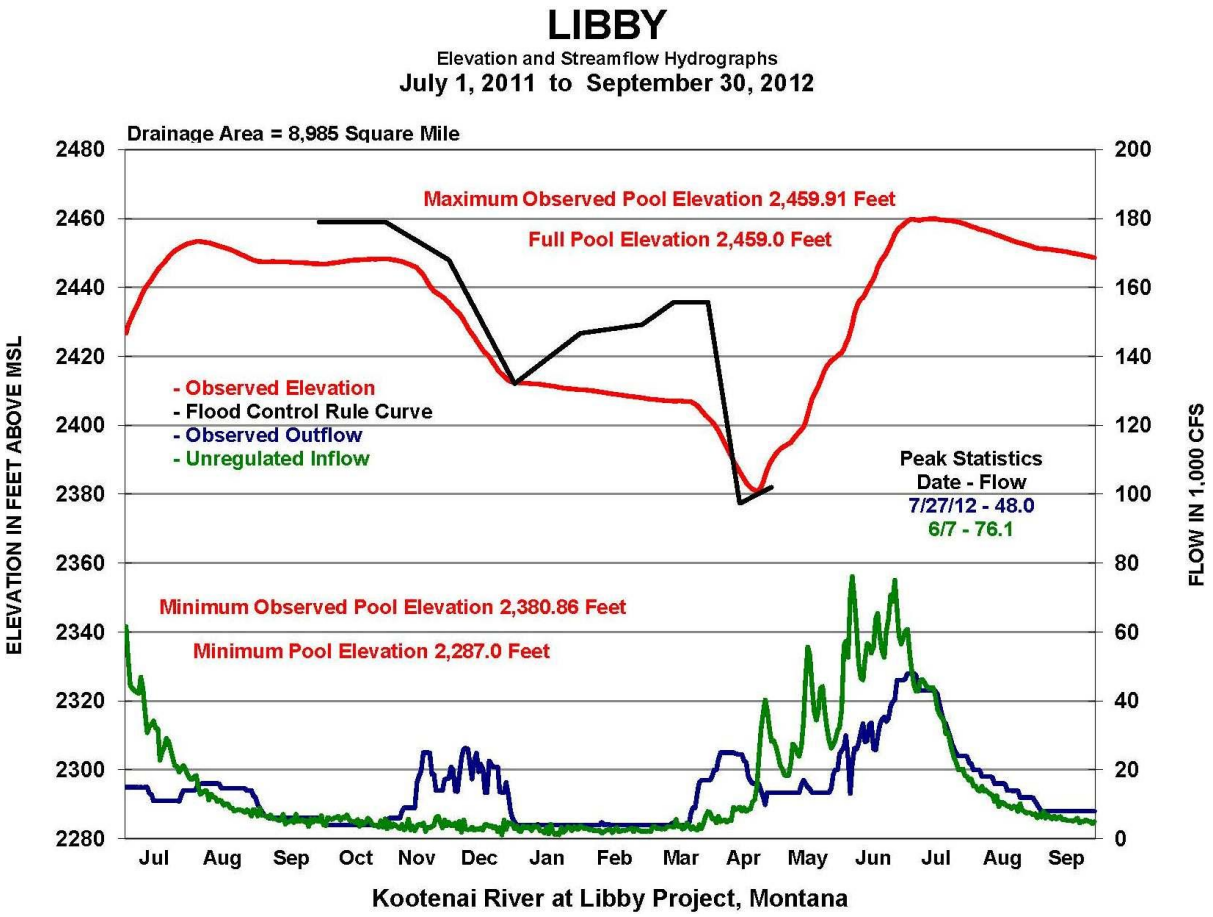


Chart 9: Regulation of Kootenay Lake

1 July 2011 – 30 September 2012

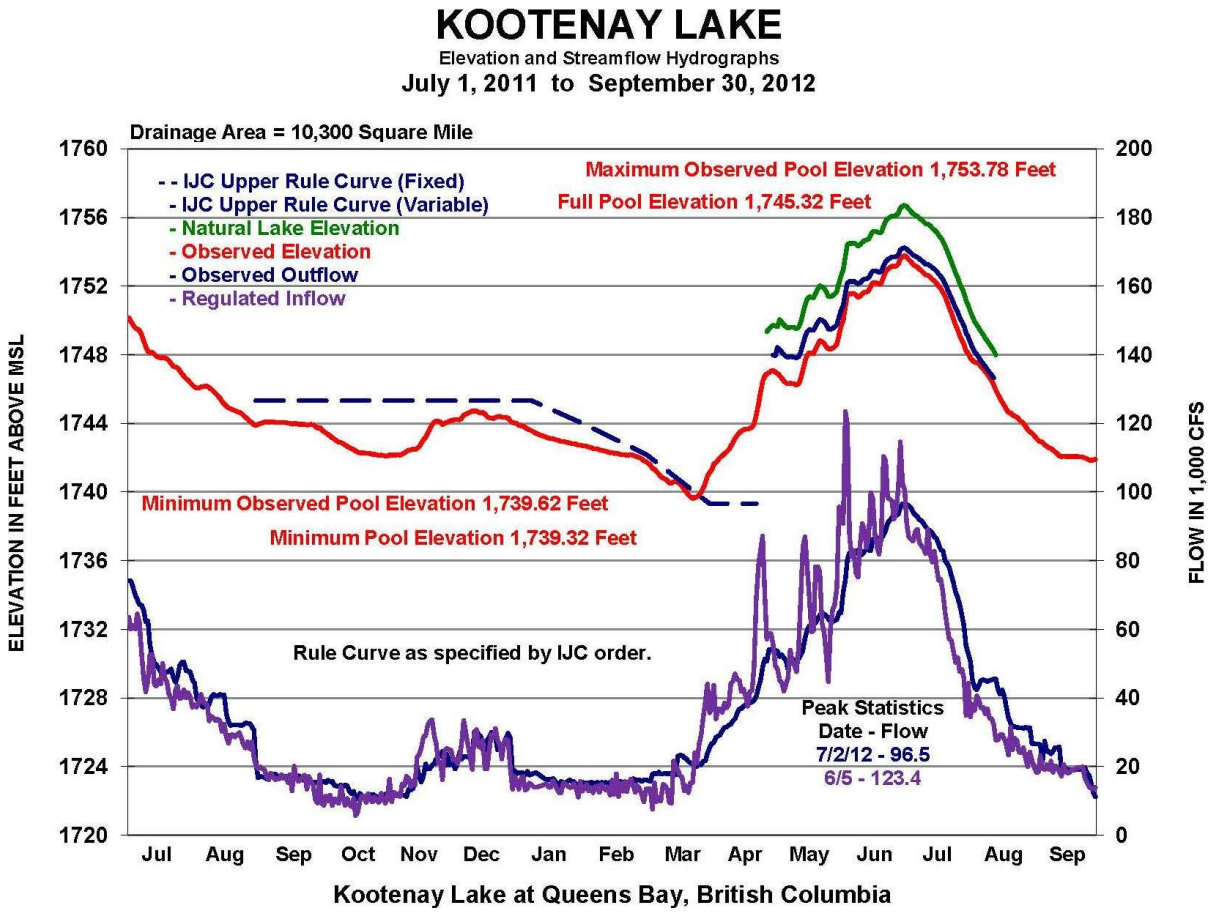


Chart 10: Columbia River at Birchbank

1 August 2011 – 30 September 2012

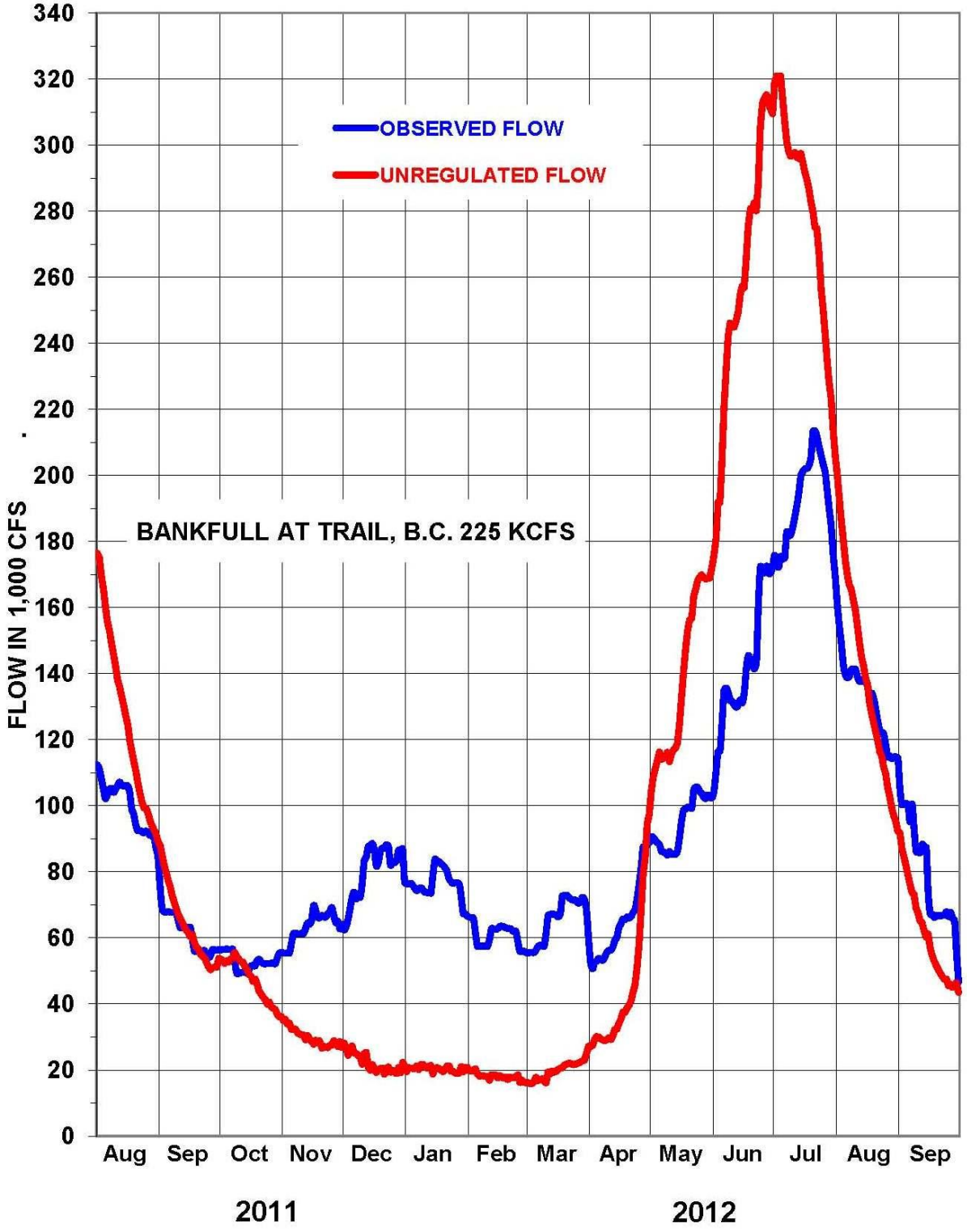


Chart 11: Regulation of Grand Coulee

1 July 2011 – 30 September 2012

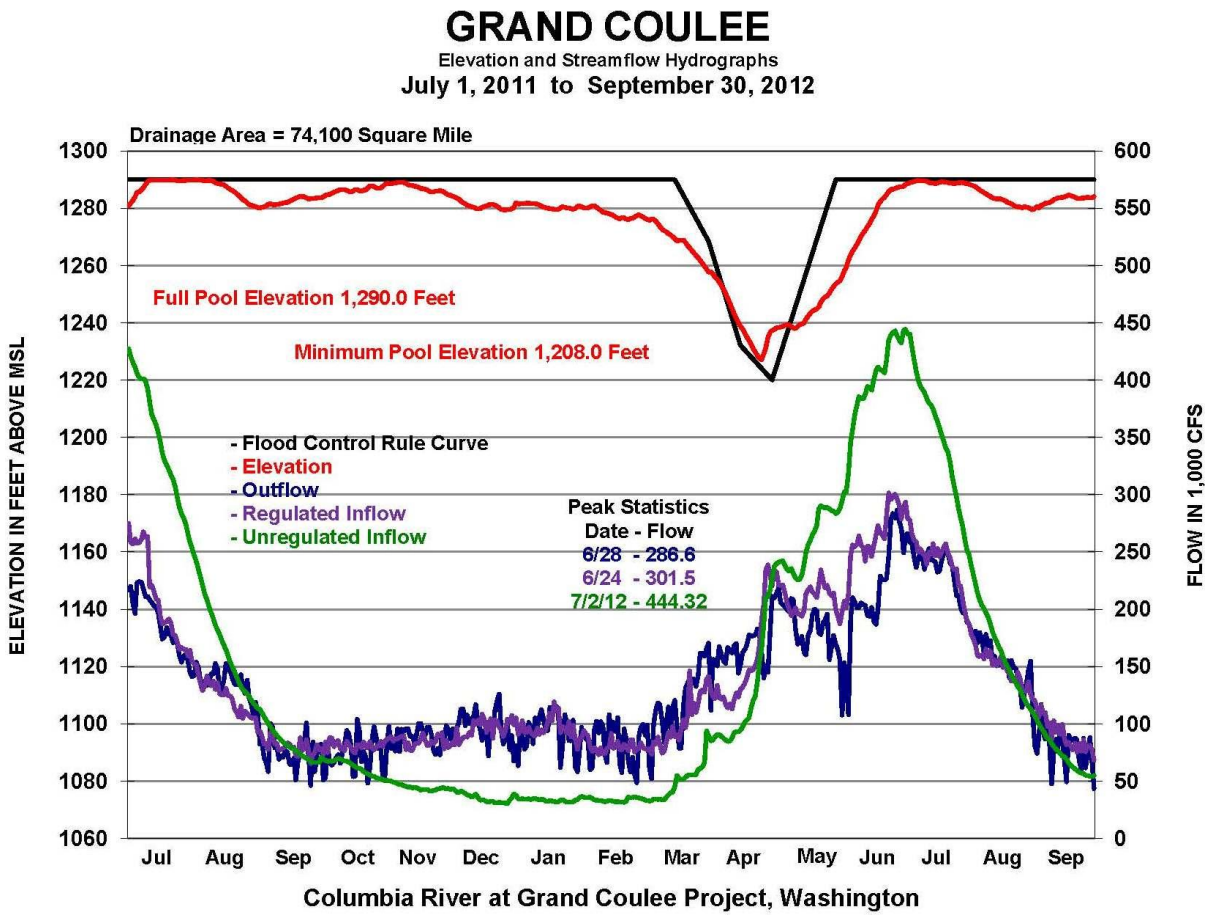


Chart 12: Columbia River at The Dalles

(Summary Hydrograph)

1 October 2011 – 30 September 2012

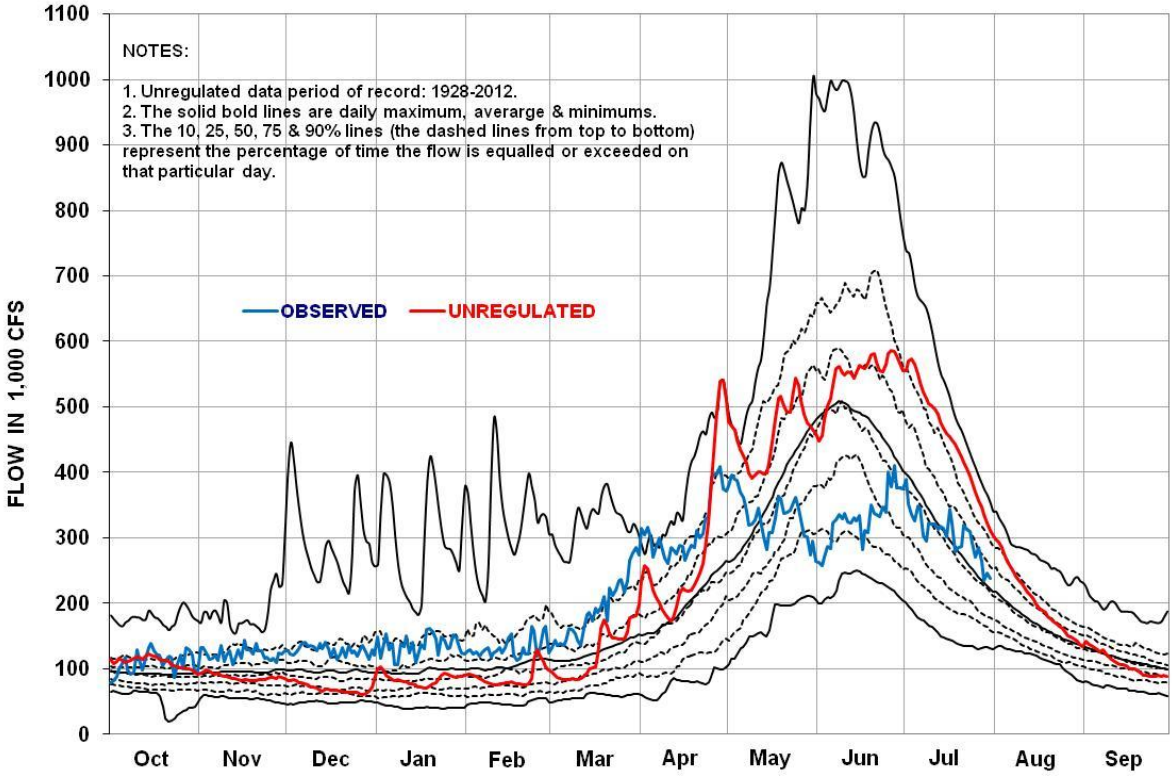


Chart 13: Columbia River at The Dalles

Re-Regulation Plot

1 April 2012 – 31 July 2012

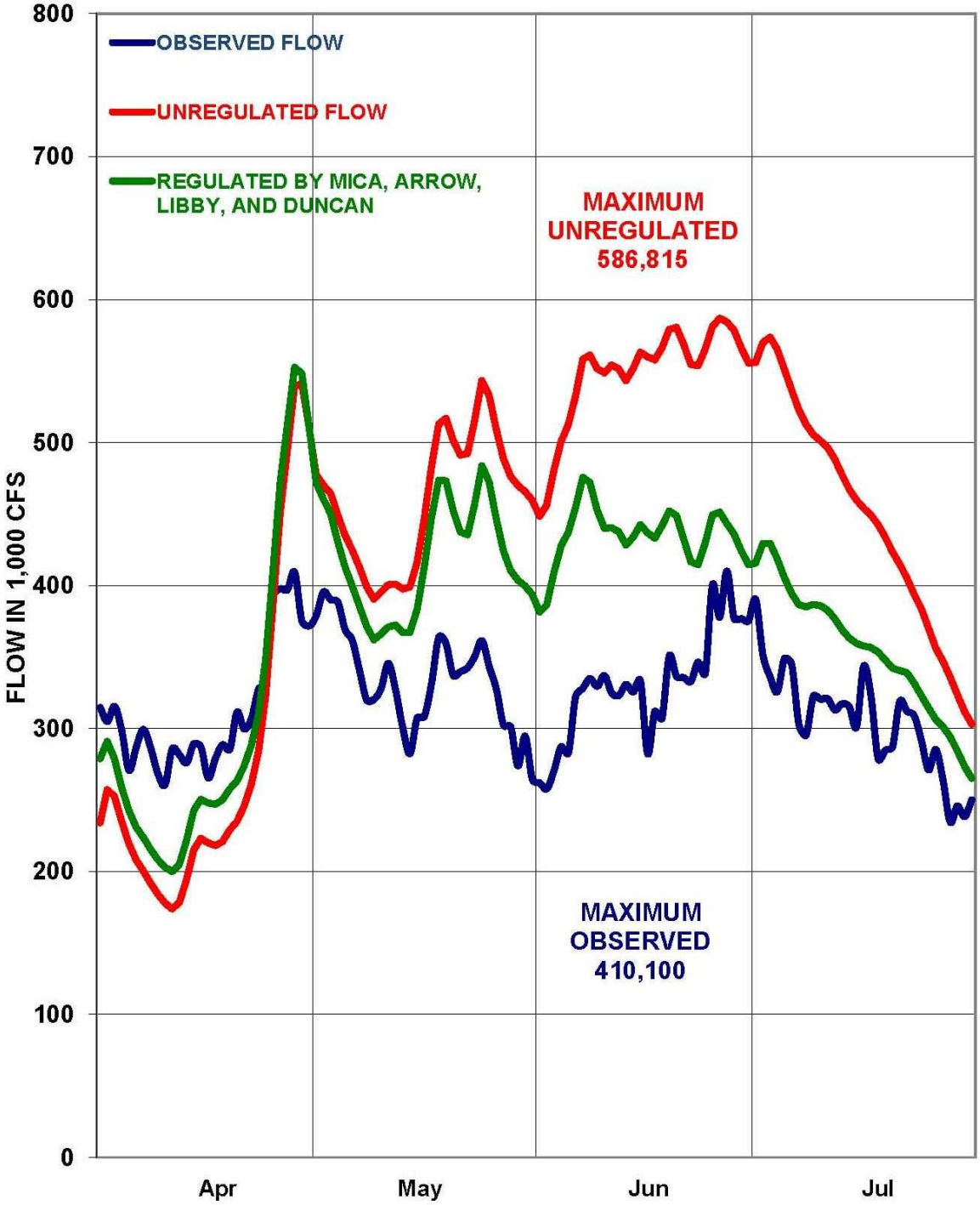
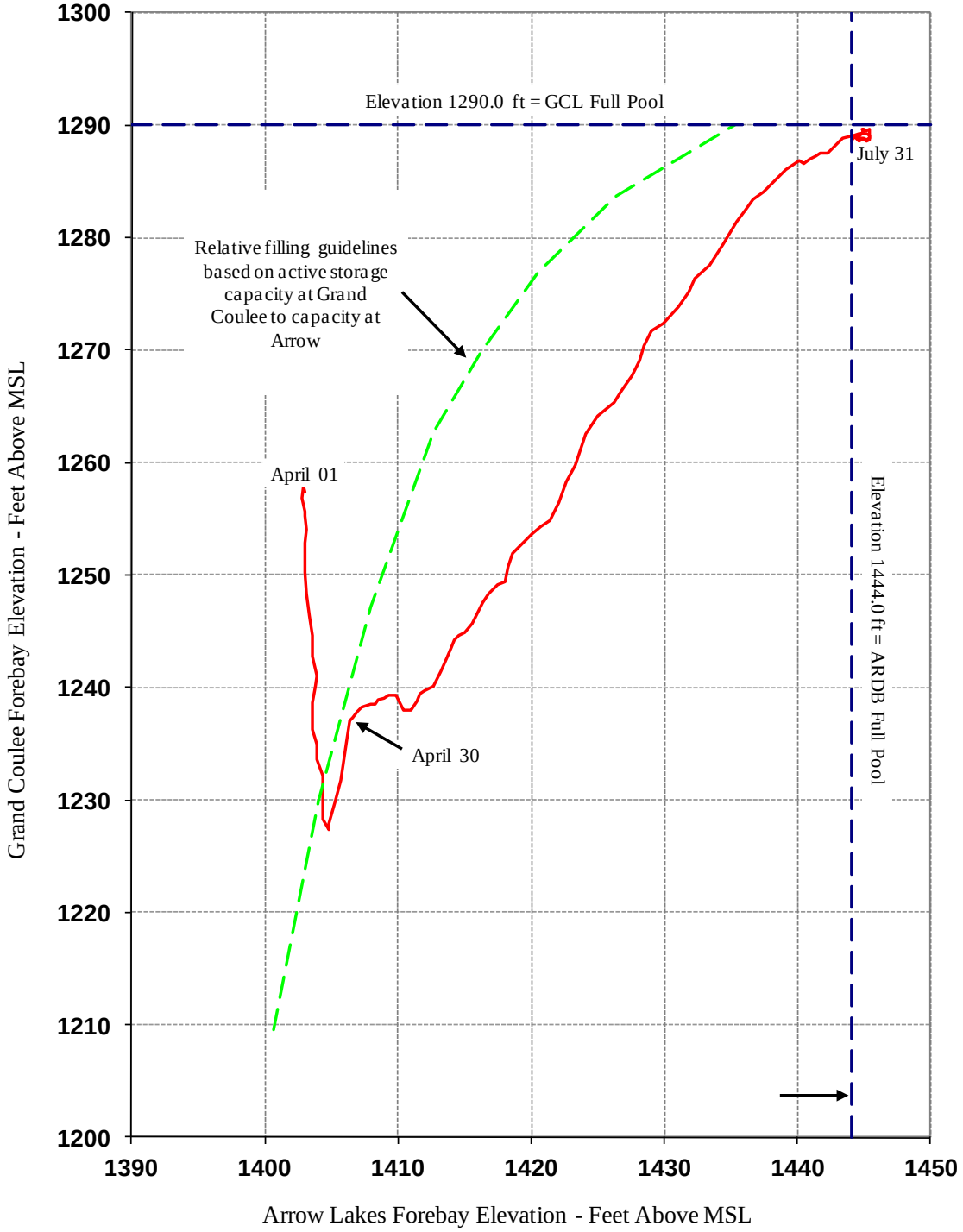



Chart 14: 2012 Relative Filling Arrow and Grand Coulee