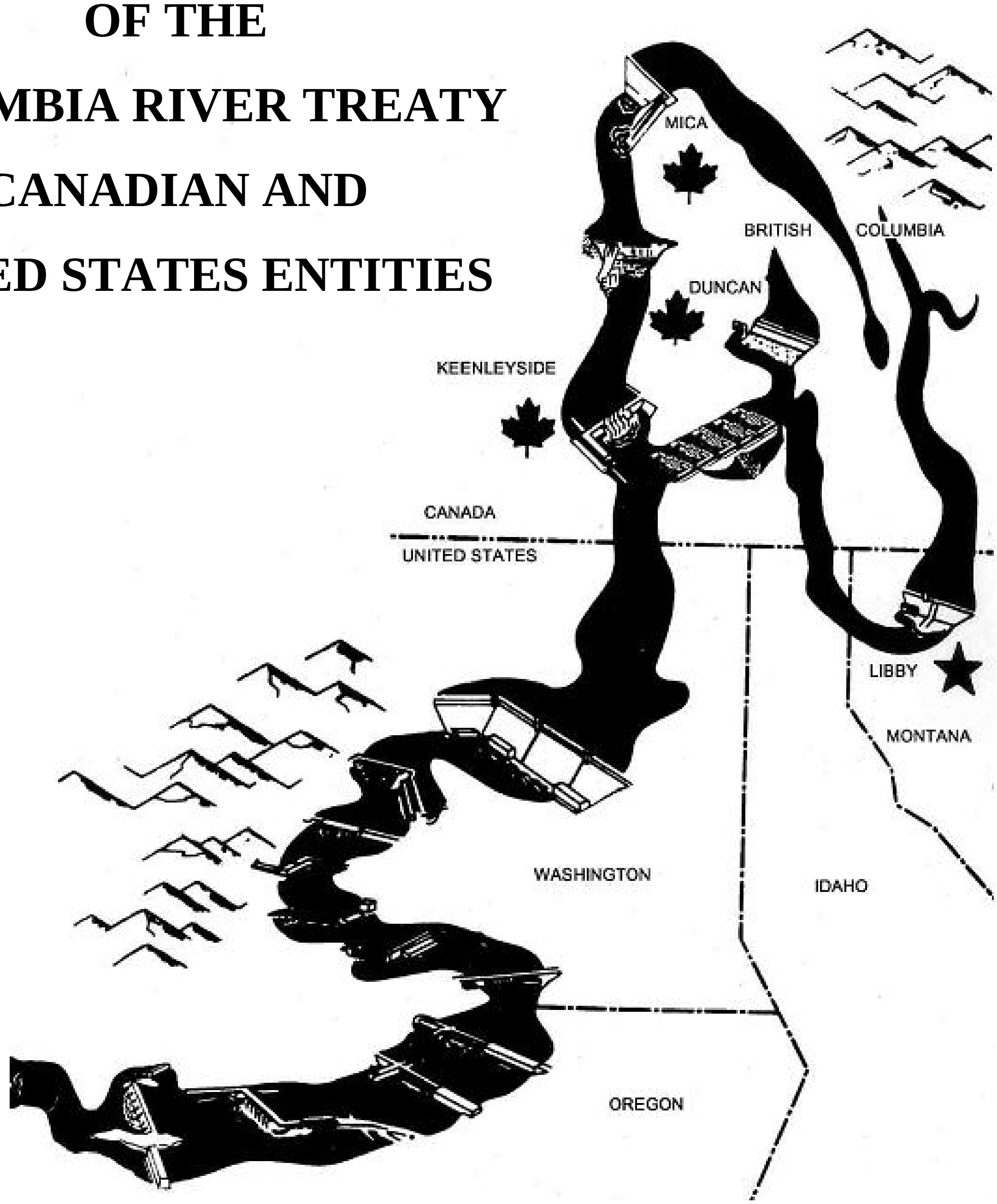
ANNUAL REPORT

OF THE

COLUMBIA RIVER TREATY

CANADIAN AND

UNITED STATES ENTITIES



FOR THE PERIOD

1 OCTOBER 2009 – 30 SEPTEMBER 2010

Dedicated to the memory of Cathy Hlebechuk,

Member of the Treaty Operating Committee,

3 October 2005 – 6 July 2009

For any feedback and comments:

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Reformatted and minor correction on 1 February 2010

EXECUTIVE SUMMARY

General

The Canadian Treaty projects, Mica, Duncan and Arrow, were operated during the 1 August 2009 - 30 September 2010 reporting period according to the 2009-2010 and 2010-2011 Detailed Operating Plans (DOPs), the 2003 Flood Control Operating Plan (FCOP), and several supplemental operating agreements described below. The Libby project was operated according to the Libby Coordination Agreement (LCA) dated February 2000, including the 13 January 2010 update to the Libby Operating Plan (LOP), and U.S. requirements for power and guidelines set forth in the U.S. Fish and Wildlife Service (USFWS) 2000 Biological Opinion, and the U.S. National Marine Fisheries Service (NMFS) Biological Opinions and Action Agency Plans, as approved by Court order. Canadian Entitlement power was delivered to Canada in accordance with the DOPs, the Entity Agreement on Aspects of the Delivery of the Canadian Entitlement dated 29 March 1999, and Entitlement related agreements described below.

Entity Agreements

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

- Columbia River Treaty Entity Agreement on the DOP for Canadian Storage 1 August 2010 through 31 July 2011, signed 29 June 2010;
- Columbia River Treaty Entity Agreement on the 2010 Summer Storage Agreement for 5 June 2010 through 10 September 2010 (10NTSSA), signed 7 July 2010; and
- Columbia River Treaty Entity Agreement on the Assured Operating Plan (AOP) and Determination of Downstream Power Benefits for Operating Year 2014-2015, signed 27 September 2010.

Columbia River Treaty Operating Committee Agreements

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

- CRTOC Agreement on Provisional Storage for the period 26 September 2009 through 3 April 2010, signed 28 September 2009; and
- CRTOC Agreement on Operation of Treaty Storage for Non-power Uses for 11 December 2009 through 31 July 2010 signed on 3 December 2009.

In addition to the Operating Committee agreements listed here, the Bonneville Power Administration (BPA) and British Columbia Hydro and Power Authority (B.C. Hydro) developed a bilateral agreement entitled “2010 Summer Storage Agreement (Not Treaty) for the period 5 June 2010 through 10 September 2010,” signed 20 May 2010.

System Operation

Under the 2009-2010 and 2010-2011 DOPs, Canadian storage was operated according to criteria from the 2009-2010 and 2010-2011 AOPs.

During the operating year, composite Treaty storage was operated very close to the Treaty Storage Regulation (TSR) composite storage plus any operations implemented under the Supplement Operating Agreements (SOAs) or the LCA, and small 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 2009 near the DOP levels as determined in the TSR study. It remained near the forecasted TSR levels through September. From October 2009 through June 2010, Canadian storage remained above the TSR, and returned to near TSR levels in July. This is primarily due to supplemental operating agreements that were implemented to achieve mutual benefits for both the U.S. and Canada.

During August and September 2009, the Canadian Entity exercised the option to provisionally draft Arrow under the LCA. This 206 hm^3 (167 kaf) provisional draft was returned (stored) by late November. The second provisional draft cycle was exercised in December through early January 2010. The draft of 305 hm^3 (248 kaf) was returned (stored) during mid February through late March 2010.

In accordance with a fall SOA, U.S. and Canada stored 1,186 hm^3 (962 kaf) combined in Canadian storage during October through early November 2009. During late December through February 2010, the U.S. Entity stored 1,232 hm^3 (1 Maf) of flow augmentation storage consistent with the provisions of the 2009-2010 Nonpower Uses agreement. Canada released its share (of half of the fall storage) by 1 January 2010 and the U.S. released its portion during one week in early December, and the remainder in March 2010. The amount of US fall storage (422 hm^3 or 342 kaf) released in March was stored as flow augmentation in February. This operation helped to shape flow augmentation outflow downstream of Hugh Keenleyside dam for Canadian fisheries operation. The flow augmentation storage was subsequently returned across July 2010 to meet U.S. salmon flow objectives.

It was mutually agreed to shape flow augmentation outflow and the 2010 Summer storage water to help smooth Arrow flows amid rapidly changing stream flow forecasts so Arrow did not result in large physical outflows and to keep Treaty accounting below full.

Canadian Entitlement

During the reporting period, the U.S. Entity delivered the Canadian Entitlement to downstream power benefits from the operation of Mica, Duncan and Arrow reservoirs to the Canadian Entity, at existing points of interconnection on the Canada-U.S. border. The amount returned, not including the reduction for transmission losses, was 567.1 average megawatts (aMW) at rates up to 1,352 MW during 1 August 2009 through 31 July 2009, and 535.7 aMW at rates up to 1,316 MW during 1 August 2010 through 30 September 2010.

During the course of the Operating Year, several curtailments of Canadian Entitlement occurred. To ensure continuity of service, transmission maintenance was postponed until after the 2010 Winter Olympics and 2010 Para-Olympics held in British Columbia were completed. Curtailments included: 2 hours in November 2009 for 1,210 MWh; 1 hour in May 2010 for 17 MWh; 1 hour in June 2010 for 10 MWh, and; 15 hours in July 2010 for 3,074 MWh. All of the curtailed power was delivered later in the month of curtailment.

Treaty Project Operation

At the beginning of the 2009-2010 operating year, 1 August 2009, actual Canadian storage was at 15.7 km^3 (12.7 Maf) or 82.0 percent full. Canadian storage ended the operating year on 31 July 2010, at 15.9 km^3 (12.9 Maf) or 82.5 percent full.

The Mica (Kinbasket) reservoir reached a maximum elevation of 751.97 m (2467.1 ft), 2.41 m (7.9 ft) below full pool on 24 September 2009. The reservoir was drawn down during the fall and winter to meet electrical demands and to prepare for the spring runoff. It reached a minimum this year at 724.7 m (2377.6 ft) on 10 May 2010, lower than the 2009 minimum level. By comparison, in 2009, the minimum level was 730.4 m (2396.2 ft) on 9 May. The lower spring levels were due to a combination of higher winter loads and consecutive months of drier fall/winter weather conditions. From late May through early July, Mica generation was reduced to near minimum flows as is normal in response to lower electrical demands and system constraints, and to achieve a high probability of refill on the reservoir. This operation, however, continued through early August due to generation restrictions at the Revelstoke generating station. By mid-August, the project resumed normal operations with the return of Revelstoke units such that generation from the Upper Columbia projects was increased to better support the Arrow Lakes reservoir levels for summer recreation. Near record high inflow event in September resulted in continued filling of Kinbasket reservoir across September through early October reaching an elevation of 753.04 m (2470.6 ft), 1.34 m (4.4 ft) below full pool on 30 September 2010. The reservoir is projected to reach a maximum of 753.5 m (2472 ft), 0.9 m (3 ft) below full pool by mid October 2010, higher by comparison to the 2009 peak level.

The Arrow Lakes reservoir reached a maximum elevation of 437.8 m (1435.6 ft) on 30 June 2009, 2.5 m (8.4 ft) below full. The reservoir drafted across fall and winter as is normal to meet Treaty firm loads. It reached a minimum level this year at 429.0 m (1407.5 ft) on 14 January 2010. By comparison, the Arrow Lakes Reservoir reached a minimum level of 429.3 m (1408.6 ft) on 30 March 2009. The higher winter/spring levels were primarily due to a combination of low Arrow Treaty discharges, refill of the July 1990 Non-Treaty Storage Agreement (NTSA) and Treaty Flex operations. As basin inflows increased from snowmelt runoff during May through early July, the reservoir filled quite rapidly up to its Treaty flood control level (maximum possible level) in June to reach a maximum level of 439.3 m (1441.3 ft), or 0.82 m (2.7 ft) below full pool on 5 July 2010. Due to a combination of generation restrictions in the upstream reservoirs in July through early August and Treaty proportional draft operation since August 2010, Arrow reservoir drafted across the summer months reaching 437.54 m, 436.11 m, 434.64 m (1435.5 ft, 1430.8 ft, 1426.0 ft) by 31 July, 31 August 31 and 30 September 2010, respectively.

Duncan reservoir refilled to 575.86 m (1,889.3 ft), 0.82 m (2.7 ft) below full pool on 21 August 2009. From September 2009 through April 2010, Duncan discharge was used to supplement inflow into Kootenay Lake and to provide spawning and incubation flows for fish. B.C. Hydro requested a permanent variance to the Duncan Flood Control Curve for 28 February 2010 and beyond from 551.0 m (1,807.7 ft) to 552.4 m (1,812.5 ft), which was subsequently approved by the U.S. Army Corps of Engineers (USACE). The additional storage on 28 February increased the ability to maintain a minimum river flow at DRL of 73 m^3/s (2.6 kcfs), for incubation of fish eggs during the March-April period as agreed to under the Duncan Water User Plan (WUP). As in most years, the reservoir was drafted to near empty in late April or early May. In 2010, however, reservoir storage draft was limited due to high inflows in April and WUP requirements preventing further increases in outflows. For this reason, the Duncan Reservoir reached its minimum level for the year of 547.1 m (1797.31 ft) on 18 April, about 1.0 m (3 ft) above the minimum licensed level. By comparison, in 2009, the reservoir reached a minimum elevation of 547.1 m (1794.9 ft) on 23 April. Reservoir discharge was reduced to a minimum of 3.0 m^3/s (0.1 kcfs) on 19 May 2010 to initiate reservoir refill. This operation continued through to early August when Duncan reservoir reached a maximum level of 576.04 m (1889.9 ft) or 0.64 m (2.1 ft) below full on 12 August 2010. The project was operated to pass inflows through the balance of August and until Labor Day (6 September) in order to reach a target of 575.5 +/- 0.3 m (1888 ft +/- 1 ft) as per WUP requirements. For the balance of September, project flows were increased to facilitate drafting of the reservoir to reach an elevation of 573.72 m (1882.3 ft) on 30 September 2010.

The Libby (Koocanusa) Reservoir filled to its maximum elevation of 744.7 m (2,443.3 ft) on 25 August 2009, 4.8 m (15.7 ft) from full pool. The reservoir drafted through the fall and winter period. By 31 December 2009, the reservoir was at elevation 734.84 m (2,410.9 ft) and operated during the winter to the VARQ storage reservation diagram. The reservoir drafted to its lowest elevation of 732.25 m (2,402.4 ft) on 17 April 2010. During the refill period, Libby Dam operated in accordance to the VARQ operating procedures with an approved deviation to remain at a minimum discharge, storing 0.32 km^3 (0.26 Maf) to increase the likelihood of meeting the minimum spillway crest elevation to provide spill as part of the sturgeon releases. Libby Dam provided 0.98 km^3 (0.8 Maf) of storage for sturgeon releases and released the storage accumulated under the deviation by 15 July. The reservoir filled to its maximum elevation of 744.6 m (2442.9 ft) on 17 August 2010, 4.9 m (16.1 ft) from full pool and drafted to elevation 744.4 m (2442.1 ft) by 31 August.

Columbia Basin Map

2010 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
CROHMS...................Columbia River Operational HydroMet Management System
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
DDPB.........................Determination of Downstream Power Benefits
DOP............................Detailed Operating Plan
DRL............................Duncan River below the Lardeau confluence
FCOP..........................Flood Control Operating Plans
ft ....feet
hm^3 ....Cubic hectometers
in ....inch
ICF ....Initial Controlled Flow
IJC..............................International Joint Commission
JSS..............................January Storage Shaping
Kaf Thousand acre feet

kcfs............................Thousand cubic feet per second
km^3 ....Cubic Kilometer (one million 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
NMFS.........................National Marine Fisheries Service
NOAA F.....................NOAA Fisheries, formerly NMFS
NTSA.........................Non-Treaty Storage Agreement
ORC...........................Operating Rule Curve
OY..............................Operating Year
PEB............................Permanent Engineering Board
PEBCOM...................PEB Engineering Committee
PNCA.........................Pacific Northwest Coordination Agreement
PNW...........................Pacific Northwest
POP............................Principles and Procedures
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
WSF...........................Water Supply Forecast
WUP...........................Water Use Plan
WY.............................Water Year

I – INTRODUCTION

This annual Columbia River Treaty Entity Report is for the 2010 water year (WY), 1 October 2009 through 30 September 2010, with additional information on the operation of Mica, Arrow, Duncan, and Libby reservoirs during the reservoir system operating year, 1 August 2009 through 31 July 2010. The power and flood control effects downstream in Canada and the U.S. are described. This report is the 44th of a series of annual reports covering the period since the ratification of the Columbia River 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 an 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 stream flow 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 the $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. 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 which cannot be resolved by the two countries 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 on 1 April 1968, Arrow on 1 April 1969, and Mica on 1 April 1973. That sale has now expired and all Canadian Entitlement has reverted to British Columbia provincial ownership and is being either delivered to the Canada-U.S. border or sold directly in the United States.

11. Canada and the U.S. each appointed Entities to implement Treaty provisions and are to jointly appoint 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 the morning of 10 February 2010 in Portland, Oregon.

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

UNITED STATES ENTITY	CANADIAN ENTITY
Mr. Stephen J. Wright, Chairman Administrator & Chief Executive Officer Bonneville Power Administration Department of Energy Portland, Oregon	Mr. David G. Cobb, Chair * President & Chief Executive Officer British Columbia Hydro and Power Authority Vancouver, British Columbia
Brigadier General John R. McMahon, Member* Division Engineer Northwestern Division U.S. Army Corps of Engineers Portland, Oregon	

* Brigadier General (BG) McMahon became the Member of the U.S. Entity on 20 November 2009, replacing BG William E. Rapp; Mr. Cobb became Chair of the Canadian Entity on 25 May 2010, replacing Robert G. Elton.

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 Acting Deputy Administrator, David J. Armstrong; Mr. Cobb's deputy is Chris K. O'Riley, Senior Vice President for Generation and Engineering; and BG McMahon's alternate is COL Robert A. Tipton (Deputy Division Engineer).

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.

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.

Those personnel are:

UNITED STATES ENTITY COORDINATORS	CANADIAN ENTITY COORDINATOR
Stephen R. Oliver, Vice President Generation Supply Bonneville Power Administration Portland, Oregon	Renata Kurschner, Director Generation Resource B.C. Hydro and Power Authority Burnaby, British Columbia

G. Witt Anderson *
Regional Director of Programs
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

* Mr. Anderson replaced David J. Ponganis on 15 February 2010, who had replaced G. Witt Anderson temporarily as Corps Coordinator while Mr. Anderson served a tour of duty with U.S. Forces-Afghanistan.

UNITED STATES ENTITY
<u>SECRETARY</u>
Dr. Anthony G. White
Regional Coordination
Power and Operations Planning
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY
<u>SECRETARY</u>
Douglas A. Robinson
Generation Resource Management
B.C. Hydro and Power Authority
Burnaby, British Columbia

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 eight members as follows:

<u>UNITED STATES SECTION</u>
Richard M. Pendergrass, BPA, Alt. Chair
James D. Barton, USACE, Alt. Chair
Steven B. Barton, USACE
John M. Hyde, BPA

<u>CANADIAN SECTION</u>
Kelvin Ketchum, B.C. Hydro, Chair
Gillian Kong, B.C. Hydro
Herbert Louie, B.C. Hydro
Alaa Abdalla, B.C. Hydro*

* Mr. Alaa Abdalla was appointed to replace Dr. Tom Siu on 1 March 2010.

The CRTOC met during the reporting period to exchange information, approve work plans, discuss issues, agree on operating plans, and brief the PEB and 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 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 studies for the 2014-2015 AOP/DDPB;
- Completed the 1 August 2010 through 31 July 2011 DOP;
- Completed two supplemental operating agreements for Canadian storage;
- Implemented the Libby Coordination Agreement (LCA) including the 13 January 2010 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;
- Briefed the PEBCOM on Entity activities, and completed the 2009 Entity Annual Report; and
- Completed and published the CRT 2014/2024 Phase 1 Report. Briefings were presented to the PEB and the PEBCOM on 10-11 February 2010.

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

Pictured from left to right: Renata Kurschner (B.C. Hydro, Coordinator), Doug Robinson (B.C. Hydro, Canadian Entity Secretary), Tony White (BPA, U.S. Entity Secretary), Rick Pendergrass (BPA, US Alt. Chair), Gillian Kong (B.C. Hydro, Member), Alaa Abdalla (B.C. Hydro, Member), Jim Barton (USACE, Alt. Chair), Steve Oliver (BPA, Coordinator), Steve Barton (USACE, Member), Kelvin Ketchum (B.C. Hydro, Canadian Chair), John Hyde (BPA, Member), Witt Anderson (USACE, Coordinator). In the background is Hungry Horse dam.

Columbia River Treaty Hydrometeorological Committee

The Hydrometeorological Committee was established in September 1968 by the Entities and is responsible for planning and monitoring the operation of data facilities in accordance with the Treaty and otherwise assisting the Entities as needed. The Committee consists of four members as follows:

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

* Ann McManamon replaced David Bright effective 31 July 2010.

It was decided in 2008 for the CRTHC to meet regularly and semi-annually. Meetings were held on 3 December 2009 and 28 June 2010, respectively, at B.C. Hydro and U.S. Army Corps of Engineers. WY2011 meetings are scheduled on 30 November in Canada, and six months later in the U.S. The 2009 Annual report was submitted on time, and the 2010 Annual Report will be completed prior to the February 2011 PEB Meeting with Bonneville Power Administration acting as lead. It was decided that, from now on, the committee will include forecast verification in the annual report. Ann McManamon, BPA, replaced David Bright as the U.S. Co-chair in July of 2010.

Forecasting

The report on the objective procedure tool to forecast onset of Kootenay Lake spring rise prepared by the CRTHC has been undergoing revisions based on the response from the Kootenay Lake Board of Control. The Seattle District had an updated water supply forecast procedure developed for the Libby basin. That forecast procedure is currently still under review by the CRTHC and a recommendation to the CRTOC should be forthcoming in the fall of 2010.

Data Exchange

Two climate stations in the U.S. used in the Kootenay Reservoir water supply forecasts lost their observers. The National Weather Service provided estimates of these stations to Canada until one station had a replacement observer contracted. The other station will be automated this coming fall. Until both the automated site and the observer are fully in place, the National Weather Service will provide estimates for these stations. This issue identified that the CRTHC needs to identify a mechanism for the National Weather Service to use when they are providing estimates rather than the actual observation for all sites.

Stations

The committee prepared a draft report on the status of hydrometeorological stations in the British Columbia portion of the basin. The draft is expected to be submitted to the October PEBCOM meeting.

The committee prepared a draft proposal for review by the CRTOC to recommend the addition of several snow pillows in the British Columbia portion of the basin. This work has been underway for a number of years but has recently gained critical mass to move forward. The initial move will be to identify those existing snow courses that might best be converted to snow pillows. If successful, these sites will not only provide daily snow information; but, if a correlation with the existing snow record can be found, then a pseudo-historical record may be generated for the new snow pillows. This process will make the snow pillow data useful much sooner than waiting for a historical record to be recorded.

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:

<u>UNITED STATES SECTION</u>	<u>CANADIAN SECTION</u>
Stephen L. Stockton, Chair Washington, D.C.	Jonathan Will*, Chair
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 is acting as the Canadian Chair of the PEB, but has not been formally installed in this position as of 7 October 2010.

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 Board for their review. The annual joint meeting of the PEB and the Entities was held on 10 February 2010 in Portland, Oregon, where the Entities briefed the PEB on the preparation and implementation of operating plans, the delivery of the Canadian Entitlement, Phase I of the 2014 CRT Review, and other topics requested by the Board.

PEB Engineering Committee

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

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

The PEBCOM met with the CRTOC on 21 October 2009 in Vancouver, BC.

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, International Columbia River Board of Control, and 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.

In fall of 2007, the Columbia River Treaty Operating Committee (CRTOC) approached the Kootenay Lake Board of Control on two issues: 1) Clarification/development of criteria for declaration of spring rise on Kootenay Lake, and 2) Influence of Kootenay Lake Order on operation of Duncan and Libby.

With respect to the spring rise issue, a letter to the IJC on Kootenay Lake Declaration of the Freshet was developed by the CRTHC and forwarded to the Kootenay Lake Board of Control Secretaries as well as FortisBC for input/comments. With respect to the operation of upstream projects, the IJC staff gave their view in an e-mail that the “Order of Approval is not directed to and does not affect the actions of the operators of the dams controlling inflows to Kootenay Lake" and said that the "The Commission concurs with this advice.” The Board of Control made no ruling on these issues at their annual meetings in September 2008. In January 2009, however, the Board ruled that:

1. Declaration of the spring rise would not be on a fixed date, but would continue to be a Board judgment call, supported by hydrometeorological information and advice from the Applicant (FortisBC).

2. Release of upstream storage (from Duncan and/or Libby) during an IJC Order exceedance does not result in a violation of the IJC Order (in addition to the accepted practice of maximizing the Kootenay Lake discharge via “free fall” operations).

The U.S. Section Chair is Ms. Lana Pollack of Ann Arbor, Michigan. The Canadian Section Chair is Joseph Comuzzi of Thunder Bay, Canada. Canadian members are Mr. Lyall D. Knott, Vancouver, B.C., and Mr. Pierre Trepanier, Montreal, Quebec. U.S. members are Ms. Irene B. Brooks of Seattle, Washington, and Dr. Samuel W. Speck of Ohio.

Presentations

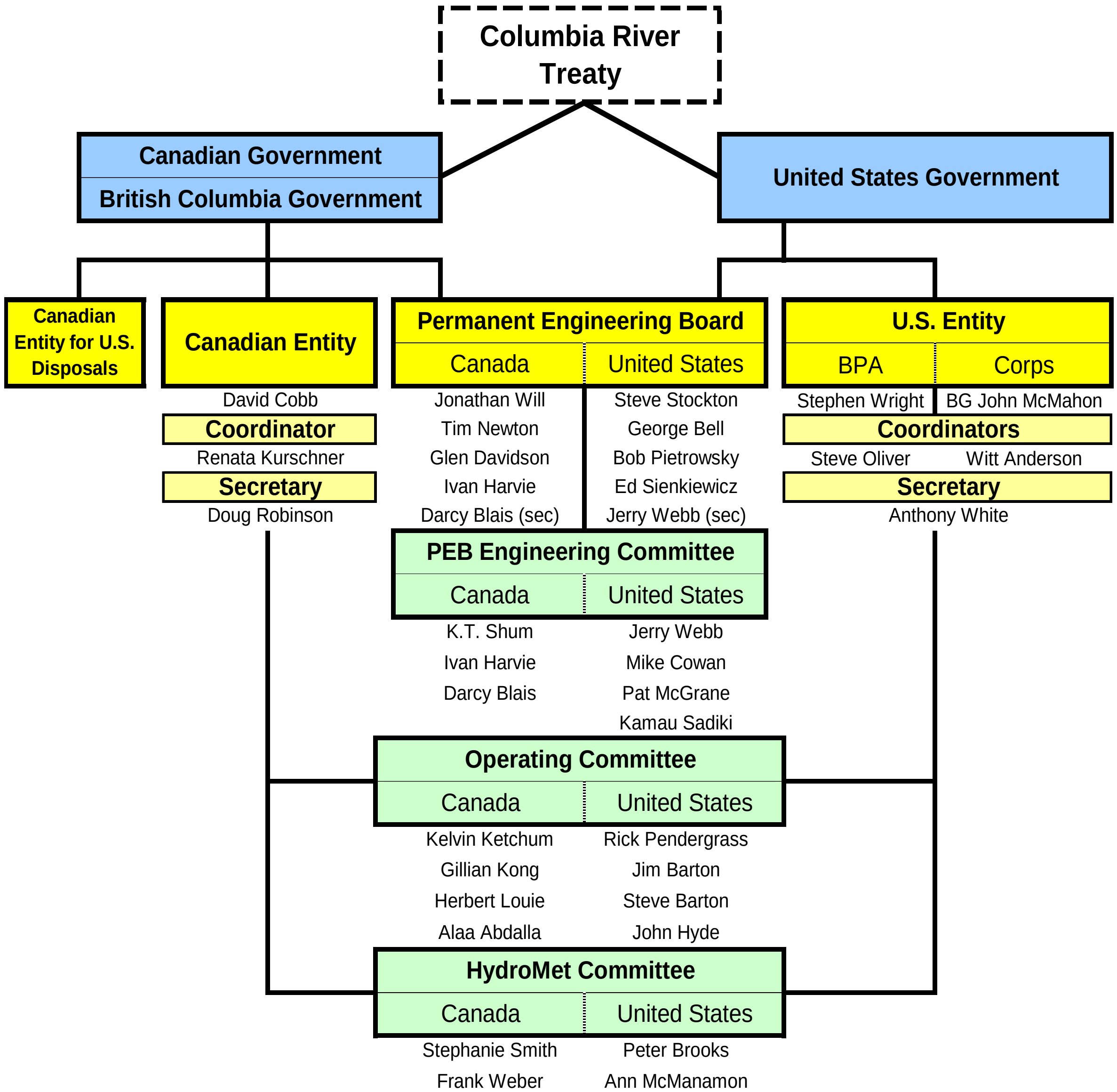
During the period covered by this report, CRT personnel made presentations about the history, structure, operations, challenges and communications associated with the CRT to visitors and inquirers from professional, environmental, academic and civic groups and individuals; new employees; Northwest Power Planning Council staff; law seminar attendees in Vancouver, BC; 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; the CERI conference in Calgary, ALB; 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.

2014/2024 Review Phase 1 Report

During the period of this annual report, the Entities completed their joint “Phase 1” power and flood control studies for the 2014/2024 CRT Review process. A Phase 1 report was released to the public on 30 July 2010, following months of extensive reviews, discussions, Entity and Coordinator meetings, and outreach meetings with stakeholders and State Department personnel. Non-disclosure agreements were prepared and signed with several parties for sharing of controlled, commercially-sensitive Canadian data and results, and letters exchanged with U.S. Departments, a state governor, and many Tribal authorities.

Columbia River Treaty Organization

Organization Chart for the Columbia River Treaty



Notes:
1) The Entities and the PEB are creations of the Treaty, and all report directly to their respective governments.
2) The Operating Committee and the HydroMet Committee report to the Entities; the PEBCOM reports to the PEB.
3) CRT XIV2(f): The Entities are tasked with "*assisting and cooperating with the PEB*".
4) CRT XV2(c): Similarly, the PEB is directed to *"assist in reconciling differences concerning technical or operational matters that may arise between the entities"*.

III - OPERATING ARRANGEMENTS

Power and Flood Control Operating Plans

The CRT requires that the reservoirs constructed in Canada be operated pursuant to flood control and hydroelectric operating plans developed hereunder. 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 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 operating year, 1 August 2009 through 31 July 2010. The operation of Canadian storage was determined by the 2009-2010 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 supplemental operating agreements. The TSR included all operating criteria from, and was based on, the Step I Joint Optimum Power Hydroregulation Study from the 2009-2010 AOP, with agreed changes. Most of the hydrographs and reservoir charts in this report are for a 14-month period, August 2009 through September 2010.

Assured Operating Plans

During the reporting period, the Entities completed studies needed to develop the 2014-2015 AOP. An Entity agreement approving the 2014-2015 AOP was signed on 27 September 2010. The 2014-2015 AOP studies are based on procedures defined in the CRT, Annexes, and Protocol and, except as noted in the AOP/DDPB document, the 2003 Principles and Procedures (POP) document and agreed appendices. However, only the first of the three streamline procedures (loads and resources) defined in POP Appendix 6 was used, since the Entities conducted a full set of Steps I, II, and III U.S. Optimum and Joint Optimum system regulation studies.

The 2014-2015 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 (ARC), 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 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 2014-2015 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.

Determination of Downstream Power Benefits

For each operating year, the DDPB resulting from Canadian storage operation is made in conjunction with the AOP according to procedures defined in the CRT, Annexes, and Protocol and, except as noted in the AOP/DDPB documents, the POP agreement. Unlike the 2013-2014 DDPB, which used all of the Streamline Procedures defined in POP Appendix 6, the 2014-2015 DDPB studies included full Steps II and III system regulation studies as described in Section 3.3 of POP.

The total downstream power benefits as a result of the operation of Canadian storage for the 2014-2015 operating year were determined to be 2,737.2 MW of dependable capacity, and 959.7 average annual MW of usable energy. Therefore, the Canadian Entitlement to downstream power benefits is 1368.6 MW of capacity, which is a 33.1 MW increase from the 2013-2014 DDPB, and 479.9 MW of average annual energy, which is a 25.6 MW decrease from the 2013-2014 DDPB. The changes to Canadian Entitlement compared to the prior DDPB are mainly due to changes in the firm loads and the amount and maintenance schedules for thermal installations.

Canadian Entitlement

For the period 1 August 2009 through 31 July 2010, the Canadian Entitlement amount, not including transmission losses, was 567.1 aMW of energy, scheduled at rates up to 1,352 MW. From 1 August 2010 through 30 September 2010, the amount, not including transmission losses, was 535.7 aMW of energy, scheduled at rates up to 1,316 MW. The Canadian Entitlement obligation was determined by the 2009-2010 and 2010-2011 AOP/DDPBs.

During the course of the Operating Year, there were 19 hours in which curtailments were made to Canadian Entitlement deliveries, primarily due to a combination of planned maintenance and unexpected weather/load-resource conditions. The total curtailed power of 4,311 MWh was returned later within the month of curtailment as agreed.

Detailed Operating Plans

During the period covered by this report, the CRTOC used the 1 August 2009 through 31 July 2010 "Detailed Operating Plan for Columbia River Treaty Storage," dated June 2009, and the 1 August 2010 through 31 July 2011 DOP, dated June 2010, 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 2009-2010 and 2010-2011 DOPs were based respectively on the 2009-2010 AOP and 2010-2011 AOP loads and resources, rule curves, and other operating criteria with agreed changes for both Canadian and U.S. projects. The 2009-2010 and 2010-2011 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 2009-2010 DOP and 2010-2011 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, the addition of a maximum January outflow limit at Arrow of 2265 m^3/s (80 kcfs), incorporation of updated forecast errors and distribution factors, 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 2010 were determined on the basis of seasonal volume runoff forecasts during actual operation. The VRC calculations for Canadian reservoirs and Libby for the 2009-2010 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 Operating Year. Provisional draft operations under the LCA are discussed in Section VI.

The most recent Libby Operating Plan (LOP) is dated 13 January 2010.

Entity Agreements

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

Date Signed by Entities	Description of Agreement
29 June 2010	Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Canadian Storage 1 August 2010 through 31 July 2011
7 July 2010	Columbia River Treaty Entity Agreement on the [BPA-BCH] 2010 Summer Storage Agreement (10NTSSA) for the Period 5 June 2010 through 10 September 2010.
27 September 2010	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2014-2015.

Columbia River Treaty Operating Committee Agreements

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

Date Signed	Description	Authority
28 September 2009	CRTOC Agreement on Provisional Storage for the Period 26 September 2009 through 3 April 2010	Detailed Operating Plan 1 August 2009 through 31 July 2010, dated 29 June 2010.
3 December 2009	CRTOC Agreement on Operation of Treaty Storage for Nonpower Uses for 11 December 2009 through 31 July 2010	Detailed Operating Plan 1 August 2009 through 31 July 2010, dated 29 June 2010.

Long Term Non-Treaty Storage Agreement

An Entity agreement dated 9 July 1990 approved the contract between B.C. Hydro and BPA relating to the initial filling of non-Treaty storage, coordinated use of non-Treaty storage, and Mica and Arrow refill enhancement. The CRTOC, in accordance with that agreement, monitored the storage operations made under this agreement throughout the operating year to insure that they did not adversely impact operation of CRT storage. The Entity agreement dated 28 June 2002 gave approval for B.C. Hydro and BPA to extend the expiration date of the contract by one year, from 30 June 2003 to 30 June 2004, which was done. Two mid-Columbia parties, Eugene Water and Electric Board and Tacoma Utilities, elected to extend their NTSA Agreement with BPA for the same one year period.

No further extension of the contract was completed, however; and, as per contract terms, release rights under the Non-Treaty Storage Agreement (NTSA) terminated effective 30 June 2004. At the end of September 2009, the B.C. Hydro and U.S. parties' accounts stood at 88.4 percent of full, full for each account being 1134.4 ksfd. There was no further refill until 29 September 2010, resulting in both B.C. and U.S. accounts 88.8 percent full on 30 September 2010. In the absence of a new agreement, the extended Provisions of the 1990 Agreement require that active Non-Treaty Storage Space in Mica be refilled prior to 30 June 2011. It was mutually agreed to fill at least at the rate of 1 ksfd/day each through future periods, until full which would be expected by early January 2011.

IV - WEATHER AND STREAM FLOW

Weather for 2009-2010

The Columbia Basin was generally warmer than normal during the summer of 2009, as a transition to El Niño weather conditions was underway. After a full year of La Niña conditions in the equatorial Pacific, the region prepared for a turn toward El Niño that would ultimately affect fall and winter weather pattern.

Late June 2009 through early July started out cooler than normal as well as wetter than normal, but quickly went into a hot weather pattern as the last half of July approached. The month opened with record low temperatures, but closed with record *high* temperatures at several locations, as well as record rainfall in spots. High pressure from the Desert Southwest expanded northward during the last half of the month.

For most of August, western sections saw seasonably warm weather, but it was areas to the east that had the most active weather, as several fronts crossed through British Columbia en route to Montana. As August closed and fall approached, the weather pattern made a turn toward cooler and wetter conditions for September.

September can often bring a mix of summer and fall weather to the Columbia Basin, but this September had a more summertime flavor than fall despite an early month tease. A strong cold front brought heavy rain and snow and cool temperatures early in the month, with strong warming about mid month before a brief run of rainy and cooler temperatures at month's end. While the early month front brought rainfall, as did a weak late month weather system, the bulk of the month was drier than normal.

The pattern of weather systems adjusted toward the end of September, so that into the first two weeks of October, progressive weather systems brought moderate to heavy rain and snow to the Columbia Basin. The coldest temperatures, relative to normal, were initially east of the Cascade Mountains, but an early season Arctic front pulled the colder air over the rest of the region as the month progressed. A warmer weather system, by mid to late month, replaced this cold system, and targeted B.C. and the northern part of the Basin with areas of significant rainfall. Drier weather appeared on the horizon as November opened, and thoughts of a more typical drier-than-normal El Niño winter crossed the minds of many water managers!

High pressure, with drier weather, sure did open up November, but this pattern gave way to a series of fronts by the middle of the month, and through the rest of the month. These were quick-moving weather systems, so precipitation was, for the most part, below normal. November temperatures were on average very mild.

As is fairly typical in El Niño winters in the Northwest and Columbia Basin, Arctic air usually finds its way south early on; and that was the case in December 2009. Leading up to December, the region was on the receiving end of a split in the jet stream; again, very typical of El Niño. As such, the month began drier than normal, with a slowly developing wetter segment mid to late month, as the split flow pattern tried to consolidate, and the air mass warmed mainly over the U.S. sector. So, 2009 closed on a transitional note, from cold and dry to wetter and milder, as El Niño conditions prevailed leading into the start of 2010. The El Niño event reached moderate status in late December, as measured according to equatorial Pacific sea surface temperatures. The expectation for spring, based on this observation, hedged toward wetter conditions. To get there, though, we had to sojourn through the toughest months of an El Niño, marked by a stubborn split flow regime.

January 2010 opened up wetter than normal, as if to tease us with another consolidation of the split flow. A series of two strong storm systems brought heavy rain and snow to the region to open up the New Year. This pattern lasted until about mid-point into the second week of the month, when the split flow pattern resumed. The southern branch of this storm track directed weather systems into California, in another, fairly classic, El Niño signature. Average temperatures across the Basin were mostly mild.

The El Niño split flow weather pattern continued into February, with weather systems diverting north and south of the Columbia Basin. Therefore, warmer- and drier-than-normal weather ruled even though the weather pattern became more active, with storms later in the month. California received the bulk of the rain and snow, while the polar branch of the storm track continued to play tag with the Upper Columbia Basin, which supplies two thirds of the stream flow at The Dalles.

The forecast for March and the rest of the spring remained consistent with most El Niño events: wetter than normal. The El Niño event that peaked in early winter was showing signs of weakening as spring ensued. A series of strong low pressure systems delivered moderate to heavy precipitation, especially during the first half of March. There was a break about mid-month, when warm weather occurred, and then storminess resumed late month. The late March precipitation increase carried forward into April, with some area breaking records for the longest stretches of rainy days for that month.

In April, the epitome of an El Niño spring following an El Niño winter occurred: increased precipitation and cooler temperatures. But, the emerging question was how quickly would we be transitioning away from El Niño and would this transition affect the weather pattern for the rest of the spring into summer? This nicely portrayed the cold first half and much warmer last half of the month. More wet weather ensued in May, with record rainfall, and mountain snowfall.

May 2010 was wet and cold: Period. There was literally a three day break in the successive parade of weather systems, and this came about mid month. The weather pattern forced a major turnaround in the stream flow profile, from drought conditions to flooding. June continued the May tradition of wet and cold, and La Niña conditions quickly emerged in the equatorial Pacific, Low pressure systems continued across the Columbia Basin for June.

The low pressure areas in June brought period of moderate rain west of the Cascades, showers, thunderstorms, some severe, east of the Range. High pressure pushed in from the North Pacific toward the end of the month, and thus the weather pattern dried. Much colder than normal sea surface temperatures along shore of B.C., Washington, and Oregon, plus the development of higher than normal pressure offshore would be the hallmark of the summer months once the June precipitation ceased. Once July arrived, so did summer.

Except for a hot early start to July, west of the Cascades, the regional temperature pattern was seasonably warm for the afternoons, but cooler than normal overnight. While there were some record high temperatures, west of the Cascades, there were about an equal number of low temperature records. When an onshore wind flow persisted, crossing the cooler than normal water along the Coast, cooler than expected temperatures resulted. July dried out steadily, as the summer weather pattern was looking more and more like La Niña summers in those years that made the switch from El Niño, which is a cooler than normal summer.

The pattern of very few hot days continued into August, as more onshore flow persisted, and only weak upper level high pressure managed to reach the area.. With the jet stream over northern British Columbia, the first couple weeks were dry and pleasant for much of the Northwest with diurnal convection over the northern Rockies and a mix of stratiform and convective precipitation over southeast British Columbia. A low pressure system developed over British Columbia and moved south into Idaho and Montana by the middle of the second week bringing strong thunderstorms to the northern Rockies. At the end of the second week, a strong high pressure ridge built over the coast and helped to break many high temperature records in this region. This ridge began to breakdown by the beginning of the third week with a wetter, cooler pattern moving in over the Northwest. This pattern continued into the fourth week of August with many areas in the Rockies experiencing freezing temperatures overnight. By midweek, things began to warm up as high pressure built over the region again. The warm-up didn't last long and was quickly followed by a strong cold front that brought cooler wetter weather to the region though the end of the month.

The Columbia Basin and areas west of the Cascade Mountains saw dry and warm conditions at the beginning of September as high pressure resided over the region. This quickly changed by the middle of the first week as an active jet stream replaced the ridge. This active pattern continued to bring disturbances over the Northwest US and southern British Columbia for the next few weeks. Most areas saw periods of showers through much of the month. with some strong showers and thunderstorms during the middle of the month. High pressure did return at the end of the month bringing warmer and drier conditions back to the region.

Columbia Basin Weather

	Temperature	Precipitation	Precipitation	Precipitation
	Pacific Northwest	Columbia River above Coulee	Snake River above Ice Harbor	Columbia River above The Dalles
Location	departure from the 1971-2000 average (ºC / ºF)	percent of the 1971-2000 average (%)	percent of the 1971-2000 average (%)	percent of the 1971-2000 average (%)
July 2009	+1.2 / +2.2	106	58	85
August 2009	+0.4 / +0.7	103	151	119
September 2009	+0.4 / +0.7	51	25	47
October 2009	-1.8 / -3.2	164	154	170
November 2009	+0.8 / +1.5	64	49	65
December 2009	-2.8 / -5.0	57	67	85
January 2010	+3.1 / +5.5	79	96	87
February 2010	+1.5 / +2.7	34	45	48
March 2010	+1.0 / +1.8	85	84	82
April 2010	-0.1 / -0.2	109	140	130
May 2010	-1.8 / -3.2	95	106	115
June 2010	-1.8 / -3.2	154	201	177
July 2010	0.1 / +0.1	60	43	52
August 2010	-0.1/-0.3	92	94	87
September 2010	+0.4/+0.9	162	71	137

Stream Flow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 July 2009 through 31 July 2010 are shown on Charts 5 to 7. Libby hydrographs are shown in Chart 8. Observed flow, as well as computed unregulated (based on the USACE stream flow model output) flow hydrographs for the same 13-month period for Kootenay Lake, Columbia River at Birchbank, Grand Coulee, and The Dalles are shown on Charts 9 to 12, respectively. Observed and unregulated (USACE) flow hydrographs at The Dalles during the April-July 2010 period, including a plot of flows occurring if regulated only by the four Treaty reservoirs, are provided in Chart 13.

The unregulated August 2009-July 2010 daily average stream flow in the Basin above The Dalles was below normal and approximately 6.8 percent lower than last year's average flow, which was also below normal. The total runoff volume at The Dalles during this same time period was 135.3 km^3 (109.7 Maf), which is 79 percent of the 1971-2000 average. Month average unregulated inflows during spring runoff were highest at The Dalles in June 2010 at 104 percent of the 1971-2000 June average. The peak-unregulated discharge for the Columbia River at The Dalles was 15,576 m3/s (550.1 kcfs) on 7 June 2010. The 2009-2010 average monthly unregulated(NWRFC) stream flows and their percentage of the 1971-2000 average monthly flows are shown in the following tables (in metric and imperial units) for the Columbia River at Grand Coulee and The Dalles.

Columbia River Unregulated Stream Flow

(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-09	82,439	2,334	79	119,797	3,392	87
Sep-09	50,988	1,444	82	80,331	2,275	86
Oct-09	32,478	920	72	68,778	1,948	83
Nov-09	35,040	992	72	78,381	2,220	83
Dec-09	25,469	721	59	64,045	1,814	65
Jan-10	30,575	866	73	79,187	2,242	77
Feb-10	28,864	817	61	74,437	2,108	61
Mar-10	38,252	1,083	61	86,603	2,452	56
Apr-10	87,238	2,470	71	163,669	4,635	69
May-10	169,742	4,807	64	287,652	8,145	66
Jun-10	293,274	8,305	95	488,050	13,820	104
Jul-10	156,731	4,438	82	226,436	6,412	88
Period Average	**86,056**	**2,437**	**77**	**151,519**	**4,291**	**79**

Seasonal Runoff Forecasts and Volumes

April-August 2010 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	Percent of 1971-2000 Average
Libby Reservoir Inflow	5.57	4.52	72%
Duncan Reservoir Inflow	2.00	1.62	79%
Mica Reservoir Inflow	11.38	9.23	82%
Arrow Reservoir Inflow	22.30	18.08	79%
Columbia River at Birchbank	39.45	31.98	79%
Grand Coulee Reservoir Inflow	58.85	47.71	79%
Snake River at Lower Granite	23.53	19.07	83%
Columbia River at The Dalles	95.48	77.41	83%

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2010 for a large number of locations in the Columbia River Basin and updated at the beginning of each month from December onwards 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. 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, in cooperation with the U.S. Army Corps of Engineers, National Resource Conservation Service, Bureau of Reclamation, and B.C. Hydro. The Libby inflow forecast is prepared by the U.S. Army Corps of Engineers. The 1 April 2010 forecast of January through July runoff for the Columbia River above The Dalles was 86.0 km^3 (69.7 Maf) and the actual observed runoff was 104.5 km^3 (84.7 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 1971-2000 period is 132.4 km^3 (107.3 Maf).

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
Minimum	93.4	76.7	69.0	69.2	66.4	68.5	66.4
Median	124.6	124.6	120.0	121.6	121.1	121.9	122.4
Maximum	170.2	178.9	180.1	183.8	188.7	196.1	196.1

The Dalles, OR Volume Runoff Forecasts in Maf (Jan-Jul)							
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Actual**
1970	82.5	99.5	93.4	94.3	95.1	--	95.7
1971	110.9	129.5	126.0	134.0	133.0	135.0	137.5
1972	110.1	128.0	138.7	146.1	146.0	146.0	151.7
1973	93.1	90.5	84.7	83.0	80.4	78.7	71.2
1974	123.0	140.0	146.0	149.0	147.0	147.0	156.3
1975	96.1	106.2	114.7	116.7	115.2	113.0	112.4
1976	113.0	116.0	121.0	124.0	124.0	124.0	122.8
1977	75.7	62.2	55.9	58.1	53.8	57.4	53.8
1978	120.0	114.0	108.0	101.0	104.0	105.0	105.6
1979	88.0	78.6	93.0	87.3	89.7	89.7	83.1
1980	88.9	88.9	88.9	89.7	90.6	97.7	95.8
1981	106.0	84.5	84.5	81.9	83.2	95.9	103.4
1982	110.0	120.0	126.0	130.0	131.0	128.0	129.9
1983	110.0	108.0	113.0	121.0	121.0	119.0	118.7
1984	113.0	103.0	97.6	102.0	107.0	114.0	119.1
1985	131.0	109.0	105.0	98.6	98.6	100.0	87.7
1986	96.8	93.3	103.0	106.0	108.0	108.0	108.3
1987	88.9	81.9	78.0	80.0	76.7	75.8	76.5
1988	79.2	74.8	72.7	74.0	76.1	75.0	73.7
1989	101.0	102.0	94.2	99.5	98.6	96.9	90.6
1990	86.5	101.0	104.0	96.0	96.0	99.5	99.7
1991	116.0	110.0	107.0	106.0	106.0	104.0	107.1
1992	92.6	89.1	83.5	71.2	71.2	67.8	70.4
1993	92.6	86.5	77.3	76.6	71.9	86.1	88.0
1994	79.7	76.3	78.1	73.2	75.5	76.4	75.0
1995	101.1	99.6	94.3	99.6	99.6	97.9	104.0
1996	116.0	122.0	130.0	126.0	134.0	141.0	139.3
1997	138.0	145.0	142.0	149.0	153.0	159.0	159.0
1998	86.4	95.2	91.7	90.8	89.1	101.0	104.0
1999	116.0	120.0	130.0	128.0	124.0	123.0	124.1
2000	105.0	106.0	105.0	105.0	105.0	102.0	98.0
2001	80.4	66.4	58.6	56.1	56.5	55.5	58.2
2002	100.0	102.0	97.3	96.4	98.2	100.0	103.8
2003	80.5	75.6	74.9	85.3	90.2	89.3	87.7
2004	103.0	100.0	92.9	84.2	79.5	85.1	83.0
2005	85.6	82.4	70.7	73.8	74.7	79.8	81.3
2006	101.0	111.0	107.0	107.0	110.0	111.0	114.7
2007	105.0	101.0	100.0	100.0	99.1	96.4	95.7
2008	102.0	103.0	103.0	101.0	97.3	98.2	99.2
2009	94.7	92.9	86.2	92.0	91.1	92.0	90.2
2010	88.5	79.2	71.8	69.7	70.9	74.0	84.7
Minimum	75.7	62.2	55.9	56.1	53.8	55.5	53.8
Median	101.0	101.0	97.3	98.6	98.2	98.9	99.2
Maximum	138.0	145.0	146.0	149.0	153.0	159.0	159.0

V - RESERVOIR OPERATION

General

The 2009-2010 operating year began with Canadian storage at 82.0 percent full. Libby reservoir (Lake Koocanusa) was about 5.4 m (18 ft) from full, elevation 744.07 m (2,441.2 ft), at the start of the operating year (1 August 2009) and releasing water to meet BiOp objectives for flow augmentation for listed salmon species in the U.S.

The water supply during the 2009-2010 operating year was below average in the Columbia Basin above Grand Coulee and the Snake River above Lower Granite. The actual runoff in the Canadian portion of the Columbia basin measured at Birchbank was 79% of normal for January through July 2010. The actual runoff for the overall Columbia basin (U.S. and Canada combined) measured at The Dalles for January through July 2010 was 79% of normal.

The CRTOC signed two operating agreements during the 1 August 2009 to 31 July 2010 operating year (see Section III Operating Arrangements). At the end of the 2009-2010 operating year, Canadian storage was at 82.5 percent on 31 July 2010.

Canadian Storage Operation

At the beginning of the 2009-2010 operating year on 1 August 2009, actual Canadian storage provided under Article II of the Columbia River Treaty (Canadian storage) was at 15.7 km^3 (12.7 Maf) or 82.0 percent full on 31 July 2009. It drafted to a minimum of 3.9 km^3 (3.0 Maf) on 15 April 2010. Canadian composite storage refilled to 15.9 km^3 (12.9 Maf) or 82.5 percent full.

As specified in the DOP, the release of Canadian storage is made effective at the Canadian-U.S. border. Accordingly, releases from individual Canadian projects can vary from the release required by the DOP TSR plus supplemental operating agreements, so long as this variance does not impact the ability of the Canadian system to deliver the sum of CRT outflows from Arrow and Duncan reservoirs. Variances from the DOP 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 DOP.

Conversely, an underrun occurs when actual project releases are less (contents are higher) than those specified by the DOP. Flex accounts for Mica, Revelstoke, Arrow, and Duncan are balanced at any point in time (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 748.1 m (2,454.4 ft) on 31 July 2009. The reservoir continued to refill to reach a maximum elevation of 751.97 m (2,467.1 ft), 2.41 m (7.9 ft) below full pool on 24 September 2009. As inflows continued to recede throughout the fall and winter period, and outflows increased to meet winter load requirements, the reservoir drafted steadily, reaching 741.4 m (2,432.3 ft) on 31 December 2009.

Influenced by dry conditions and relatively high demand for electricity this year, Kinbasket reservoir reached a minimum elevation of 724.7 m (2377.6 ft) on 10 May 2010, 5.7 m (18.6 ft) lower than the 2009 minimum level of 730.4 m (2,396.2 ft) on 9 May. From mid-May through early July, Mica generation was reduced to near zero as system loads declined and inexpensive market energy was available. This operation continued through early August due to generation restrictions at the Revelstoke generating station. By mid August, the project resumed normal operations with the return of Revelstoke units such that generation from the Upper Columbia projects was increased to better support the Arrow Lakes reservoir levels for summer recreation. Near record high inflow event in September resulted in continued filling of Kinbasket reservoir across September through early October reaching an elevation of 753.04 m (2470.6 ft), 1.34 m (4.4 ft) below full pool on 30 September 2010. The reservoir is projected to reach a maximum of 753.5 m (2472 ft), 0.9 m (3 ft) below full pool by mid October 2010, higher by comparison to the 2009 peak level.

Inflow into Mica reservoir was 85 percent of normal over the period August 2009 to December 2009. Over this same period, Mica outflow varied from a monthly average low of about 385.11 m^3/s (13.6 kcfs) in September to a monthly average high of about 1090.20 m^3/s

(38.5 kcfs) in December. Inflow into Mica reservoir was about 89 percent of normal over the period January to July 2010. Outflow over this same period varied from a monthly average high of 937.29 m^3/s (33.1 kcfs) in January to a monthly average low of 13.02 m^3/s (0.46 kcfs) in July.

The Mica project had an underrun of 1804.9 cubic hectometers (hm^3) (737.7 thousand second-foot-days (ksfd) on 31 July 2009. As of 30 September 2010, the underrun was 2018.7 hm^3 (825.7 ksfd) which was also the maximum underrun for the period of record and the minimum was -1255.1 hm^3 (-513.0 ksfd) on 10 May 2010.

The B.C. Hydro Non-Treaty Storage Agreement (NTSA) active storage account was at 2,452.8 hm^3 (1,002.6 ksfd) on 31 July 2009. The corresponding U.S. NTSA account was at 2451.6 hm^3 (1002.1 ksfd). Due to low water conditions, there was no Non-Treaty storage activity during the 2009-10 operating year. However, good progress has been made so far in refilling NTSA storage during the 2008/2009 operating year resulting in a combined U.S. and Canada NTSA storage space at 89 percent full as of 30 September 2010. The NTSA terminated, with respect to release rights, on 30 June 2004. Under the NTSA Extended Provisions, active storage accounts must be refilled no later than 30 June 2011.

Revelstoke Reservoir

During the 2009-2010 operating year, the Revelstoke project was operated as a run-of-river plant with the reservoir level maintained generally within 0.91 m (3.0 ft) of its normal full pool elevation of 573.02 m (1,880.0 ft). During the spring rise, March through July, the reservoir operated as low as elevation 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 early July through early August, the project releases were restricted due to the installation and testing of Revelstoke unit 5. Changes in Revelstoke storage levels or flows did not affect CRT storage operations.

Arrow Reservoir

As shown in Chart 6, the Arrow reservoir was at elevation 436.65 m (1,432.6 ft) on 31 July 2009, 3.48 m (11.4 ft) below full pool. Arrow reservoir was drafted in the fall and winter to meet Treaty firm loads reaching 429.52 m (1,409.2 ft) on 31 December 2009, lower than normal for this date. The reservoir continued to draft to reach its minimum level of the year at elevation 429.00 m (1407.5 ft) on January 14, 2010. By comparison, the Arrow Lakes Reservoir reached a minimum level of 429.3 m (1408.6 ft) on March 30, 2009. The higher winter/spring levels were primarily due to a combination of low Arrow Treaty discharges, refill of the July 1990 Non-Treaty Storage Agreement (NTSA) and Treaty Flex operations.

As basin inflows increased from snowmelt runoff, the Arrow Lake reservoir continued to refill up to its Treaty flood control level (maximum possible level) in June. The reservoir reached a maximum elevation for the year of 439.3 m (1441.3 ft), or 0.82 m (2.7 ft) below full pool on July 5, 2010. By comparison in 2009, the Arrow Lakes reservoir reached a maximum elevation of 437.8 m (1435.6 ft) on June 30, 2.5 m (8.4 ft) below full. The last time the reservoir filled to within 1 ft below full was on 6 July 2008. Due to a combination of generation restrictions in the upstream reservoirs in July through early August and Treaty proportional draft operation since August 2010, Arrow reservoir drafted across the summer months reaching 437.54 m, 436.11 m, 434.64 m (1435.5 ft, 1430.8 ft, 1426.0 ft) by 31 July, 31 August and 30 September 2010 respectively.

Local inflow into Arrow reservoir was significantly below normal at 74 percent over the period August to December 2009. Arrow outflow varied from a monthly average low of approximately 765 m^3/s (27 kcfs) in October to a monthly average high of 1585.7 m^3/s (56 kcfs) in December. Local inflow into Arrow reservoir was 84 percent of normal over the period January to July 2010. Outflow over this same period varied from a monthly average high of 1,245.9 m^3/s (44 kcfs) in July to a monthly average low of 424.8 m^3/s (15 kcfs) in April.

As in past years, the Non-Power Uses agreement was negotiated with the U.S. in order to manage Arrow Lakes Reservoir outflows to protect whitefish and rainbow trout spawning and incubation downstream of the Hugh Keenleyside Dam. As a result, from 1 January to 19 January 2010, Arrow outflow was held on average 1189.3 m^3/s (42 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 2010. Arrow outflow, from February through March 2010, was held above 736.2 m^3/s (26 kcfs), on average, to help protect deposited eggs. These flow changes resulted in a Tier 1 protection level for whitefish for the 2009-10 operating year. During April and May 2010, Arrow outflows were maintained at or above 424.8 m^3/s (15 kcfs) to ensure successful rainbow trout spawning below Arrow at water levels that could be maintained until hatch. Storage under this agreement, as well as other supplemental agreements, helped to increase the Arrow Lakes Reservoir level during the January through August period.

The CRTOC also negotiated and signed other supplemental operating agreements to improve reservoir and river operations in Canada and the U.S. during 2009-2010:

- The 2009-2010 Fall Storage Agreement, signed by the Treaty entities in September 2009, allowed Arrow Treaty releases to be reduced in late September through early December. The two countries shared power and fisheries benefits from the agreement.
- A Summer Storage Agreement, signed in May 2010, allowed Arrow Treaty releases to be reduced in June to improve Arrow summer levels and provided additional power benefits for both countries.

Duncan Reservoir

Operation of the Duncan reservoir during the 2009-2010 operating year implemented the operational constraints agreed upon in the Duncan Water Use Plan (WUP) and ordered in the Water License Order (issued on 21 December 2007). As shown in Chart 7, the Duncan reservoir refilled to 575.86 m (1,889.3 ft), 0.82 m (2.7 ft) below full pool on 21 August 2009. Duncan discharges were adjusted for the balance of August to target a reservoir elevation of 575.46 m (1,888 ft) by the end of August/early September as per the WUP requirements.

Discharges were increased to about 198 m^3/s (7 kcfs) in early September 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 the Duncan River below the Lardeau confluence (DRL) gauging station 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) and maintained until 21 December, at which point flows were gradually ramped up to about 227 m^3/s (8 kcfs) to help support whitefish flows downstream of Keenleyside Dam. For the first three weeks of January 2010, Duncan discharge was kept fairly high, near 227 m^3/s (8 kcfs), to draft the Duncan reservoir and to help reduce Arrow flows in aid of whitefish spawning.

As in most years, Duncan reservoir was drafted to near empty in late April or early May. In 2010, however, reservoir storage draft was limited due to high inflows in April and Water Use Plan requirements preventing further increases in outflows. For this reason, the Duncan Reservoir reached its minimum level for the year of 547.1 m (1797.31 ft) on 18 April, about 1.0 m (3 ft) above the minimum licensed level. By comparison, in 2009, the reservoir reached a minimum elevation of 547.1 m (1794.9 ft) on 23 April. Reservoir discharge was reduced to the minimum of 3 m^3/s (0.1 kcfs) on 19 May 2010 to initiate refill. Duncan reservoir continued to pass the minimum flows until early August when discharges were gradually increased to control the rate of refill.

Duncan reservoir reached a maximum level of 576.04 m (1889.9 ft) or 0.64 m (2.1 ft) below full on 12 August 2010. Duncan discharges were adjusted as needed across August through to 6 September (Labor Day) to target a reservoir elevation of ~575.46 +/- 0.3 m (~1,888 +/- 1 ft) to meet WUP objectives. For the balance of September, project flows were increased to facilitate drafting of the reservoir to reach an elevation of 573.72 m (1882.3 ft) on 30 September 2010.

B.C. Hydro requested a permanent variance to the Duncan Flood Control Curve for 28 February 2010 and beyond from 551.0 m (1,807.7 ft) to 552.4 m (1,812.5 ft), which was subsequently approved by the Corps. The additional storage on 28 February increased the ability to maintain a minimum river flow at DRL of 73 m^3/s (2.6 kcfs) for incubation of fish eggs during the March-April period as agreed to under the Duncan WUP.

Libby Reservoir

Operation of Libby Dam and Lake Koocanusa is shown in Chart 8 of this document. Lake Koocanusa began July 2009 at elevation 741.3 m (2,432.1 ft), 8.2 m (26.9 ft) from full.

Inflow to the reservoir was near 532 m^3/s (18.8 kcfs) at the beginning of July and receded to approximately 269 m^3/s (9.5 kcfs) by the end of the month. Outflow from Libby was 340 m^3/s (12.0 kcfs), at the start of July, ramping down from sturgeon operations, and reached bull trout minimums of 198 m^3/s (7.0 kcfs) on 13 July. Outflow continued at bull trout minimums in August as model guidance suggested conditions such that the reservoir was unlikely to fill to the 31 August target elevation of 746.5 m (2,449 ft). Libby reached a maximum elevation of 744.7 m (2443.3 ft) on 23 August 2009.

Outflows during September 2009 were 170 m^3/s (6.0 kcfs), minimum for bull trout. On 6 September, the outflow was reduced to the bull trout. The reservoir elevation on 30 September was 744.2 m (2,441.5 ft). In early October, the outflow was reduced to 127 m^3/s (4.5 kcfs), which is near minimum project outflow of 4.0 kcfs. Outflows from Libby Dam remained at 127.4 m^3/s (4.5 kcfs) until 9 November when weekly and daily load shaping for power objectives began. Load shaping outflow from the dam was generally higher during the week, and slightly less on weekends, and higher during the day and less at night. All changes in outflow followed the ramp rate restrictions as described in the 2006 U.S. Fish and Wildlife Service (USFWS) Biological Opinion. The average outflow from the dam in November was 209 m^3/s (7.4 kcfs). The reservoir elevation on 30 November was 742.1 m (2,435.6 ft).

Daily and weekly load shaping continued at Libby in December, with an average monthly outflow of 519 m^3/s (18.3 kcfs). In early December, the Corps prepared a water supply forecast (WSF) for Libby inflow for the April through August period. This early season forecast was 8.09 km^3 (6.56 Maf), 103 percent of average. Because the forecast was greater than 5.9 Maf, the end of December flood control evacuation requirement was 2.5 km^3 (2.0 Maf), and the project was operated to reach an elevation of 734.9 m (2,411 ft) by the end of the month. The reservoir elevation on 31 December 2009 was 734.9 m (2,410.9 ft).

In January through April, the dam was operated to target each end of month flood control elevation to meet the objectives of the National Oceanographic and Atmospheric Administration (NOAA) Fisheries Biological Opinion. The January 2009 WSF declined to 7.05 km^3 (5.71 Maf), 90 percent of average. The resultant end of January VARQ upper flood control limit was 744.4 m (2,422.4 ft). On 1 January, the project outflow was reduced to minimum outflow of 113 m^3/s (4.0 kcfs). The 31 January reservoir elevation was 734.1 m (2,408.6 ft). The WSF for February and March continued to decrease. The February WSF was 6.76 km^3 (5.48 Maf), 86 percent of average, and the March forecast was 6.27 km^3 (5.08 Maf), 80 percent of average. The end of February flood control upper limit was 742.6 m (2,436.4 ft) and the 15 and 31 March flood control upper limits were 744.0 m (2,441.1 ft) and 744.9 m (2,444.0 ft), respectively. Due to decreasing forecasts and low reservoir inflows, Libby Dam releases were held at minimum outflow or 113.3 m^3/s (4.0 kcfs) during February and March. The 28 February and 31 March reservoir elevations were 733.3 m (2,406.0 ft) and 732.6 m (2,403.6 ft), respectively.

The April WSF had increased to 6.29 km^3 (5.10 Maf), 81 percent of average. The resultant flood control upper limits were 745.4 m (2,445.7 ft) and 746.0 m (2447.5 ft) for 15 and 30 April, respectively. The Initial Control Flow (ICF) was declared on 27 April 2010, initiating system refill operations. The USFWS determined sturgeon operations in the previous two years to be unsuccessful, allowing for spill as part of the sturgeon flows in the years 2010 through 2012, as specified in the Reasonable and Prudent Alternative in the 2006 USFWS Libby Biological Opinion, as clarified. Model guidance suggested that following the Variable Flow (VARQ) flood control procedures posed significant probability of not reaching minimum spillway crest elevations to allow the spill test. The Corps approved a request to remain at minimum discharge until a maximum of 0.32 km^3 (0.26 Maf) was stored to increase the likelihood of meeting minimum spillway crest elevation in May to provide spill. The stored volume was to be released no later than 30 June 2010. The proposal (termed Phase II Storage) was coordinated with the Technical Management Team without objection and was discussed during the April 2010 CRTOC Meeting. The project continued to release minimum outflows for the entire month and the 30 April reservoir elevation was 733.7 m (2,407.1 ft).

The May 2010 WSF decreased to 6.03 km^3 (4.88 Maf), 77 percent of average. Libby continued to discharge 113 m^3/s (4.0 kcfs) until 15 May, when discharge increased to bull trout minimum of 170 m^3/s (6.0 kcfs). Discharge then increased to the calculated VARQ minimum outflow of 411 m^3/s (14.5 kcfs) on 22 May when project reached the Phase II Storage limit. The 31 May reservoir elevation was 737.4 m (2,419.3 ft).

The June 2010 WSF decreased further to 5.44 km^3 (4.41 Maf), 70 percent of average. Libby began the month releasing the 501 m^3/s (17.7 kcfs) to begin releasing some of the Phase II storage. Based on the established 2006 USFWS BiOp procedures to provide sturgeon flow augmentation, the available sturgeon volume was computed to be 0.99 km^3 (0.8 Maf). The USFWS requested that this volume begin to be released when Kootenai River temperatures at Bonner's Ferry, Idaho, reach 8° C and Koocanusa Reservoir warmed such that 566-708 m^3/s (20.0 -25.0 kcfs) could be released through the turbines and between 142 and 283 m^3/s (5.0 and 10.0 kcfs) through the spillway without decreasing Kootenai River temperatures by more than 1.5° C. Reservoir elevations were adequate to provide spill and increases in discharge for the sturgeon operation commenced on 9 June. Releases were ramped up to full powerhouse outflow near 764.6 m^3/s (27 kcfs) and then held for one day before initiating spill, discharging a total near 963 m^3/s (34.0 kcfs) for 7 days. Spill was limited by Total Dissolved Gas (TDG) limits set forth in the Water Quality Waiver issued by the State of Montana. Spill ceased on 17 June and discharges were reduced gradually from full powerhouse using the remaining volume available for sturgeon. The remainder of the Phase II Storage was released to extend the receding discharges, reaching 255 m^3/s (9.0 kcfs) on 6 July and reducing to bull trout minimums 198 m^3/s (7.0 kcfs) on 15 July. Libby continued discharging bull trout minimum through August. The reservoir elevation on 31 July and 31 August were 744.3 m (2,441.8 ft) and 744.4 m (2,442.1 ft), respectively. On 17 August, Lake Koocanusa reached its maximum elevation of 7446 m (2,442.9 ft), 4.9 m (16.1 ft) from full. On 1 September, discharges were adjusted to reach the target elevation of 743.4 m (2,439.0 ft) by 30 September.

Kootenay Lake

As shown in Chart 9, the level of Kootenay Lake at Queens Bay was at elevation 531.27 m (1,743.0 ft) on 31 July 2009. As runoff receded across August, Kootenay Lake reservoir began to draft and discharges were adjusted to control reservoir levels slightly below the IJC limits. When the Kootenay Lake level measured at Nelson was drafted below the trigger elevation of 531.36 m (1,743.32 ft) on 19 July 2009, discharges were adjusted to keep the lake level at or below the control level until the end of August 2009.

Target minimum flows downstream of Brilliant flows are 18 kcfs from December to September and 16 kcfs during October and November. These target minimums are subject to water availability.

By 31 December 2009, Kootenay Lake was at an elevation of 531.74 m (1,744.5 ft), 0.23 m (0.77 ft) below the maximum IJC level. Kootenay Lake drafted from January to early April to remain below the IJC Order level and to meet generation requirements. Kootenay Lake reached a minimum elevation of 529.92 m (1738.6 ft) on 16 April 2010 similar to last year annual minimum level.

The International Kootenay Lake Board of Control, after consultation with FortisBC, declared the Commencement of Spring Rise for Kootenay Lake on 17 April 2010. Following the declaration of spring rise, Kootenay Lake was operated in accordance to the IJC lowering formula. Kootenay Lake discharge was passing the Grohman Narrow maximum flow for the balance of April through to early May. Lake discharges were adjusted in the spring/summer in response to the low inflows and to improve refill of the Kootenay Lake reservoir. Inflow peaked at 2098.3 m^3/s (74.1 kcfs) on 14 June 2010. Discharge from the lake peaked at 1758.5 m^3/s (62.1 kcfs) on 16 June 2010. Kootenay Lake reached a peak elevation of 532.97 m (1748.6 ft) on 18 June 2010. By comparison, in 2009, the peak level was at 532.74 m (1,747.84 ft) on 19 June.

As runoff receded during June, Kootenay Lake Reservoir began to draft and discharges were adjusted to control reservoir levels slightly below the IJC limits. When the Kootenay Lake level measured at Nelson was drafted below the trigger elevation of 531.36 m (1,743.32 ft) on 17 July 2010, discharges were adjusted to keep the lake level at or below the control level until the end of August and target the minimum flow below Brilliant (as flows are available).

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 2009-2010 and 2010-2011 DOPs were designed to achieve optimum power generation at-site 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 Treaty Storage Regulation study (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 – 4 and 2M – 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 during October through November 2009 as described in the LOP and 2003 CRT FCOP. The December forecast was 103 percent of average. Based on this forecast, the recommended draft for Libby reservoir was 2.47 km^3 (2 Maf), to elevation 734.9 m (2,411 ft) on 31 December.

Libby was operated to its VarQ (Variable Flow) flood control storage reservation diagram in December through spring period. Lake Koocanusa was below the end of April flood control elevation because despite Libby Dam passing minimum flow all the way from January through the end of April, there was insufficient inflow to fill up to the flood control elevation. During the refill period from late April through June, Libby Dam operated in accordance with the VarQ Operating Procedures except in May when there was an approved deviation from VarQ to remain at minimum flow to store the amount needed to provide spill in May for sturgeon. The reservoir filled to within 4.9 m (16.1 feet) of full in August 2010.

Flood Control

The 2010 WSF's averaged below normal across the Columbia River Basin, Upper Columbia Basin, and the Snake River Basin. The reservoir system, including the Columbia River Treaty projects, was required to draft for flood control in preparation for the spring rise. Inflow forecasts and reservoir regulation modeling were done weekly throughout the winter and spring. Projects were operated according to the May 2003 FCOP. The unregulated peak flow (based on the USACE SSARR program output) at The Dalles, Oregon, shown on Chart 13, was estimated at 15,576 m^3/s (550.06 kcfs) on 7 June 2010, and a regulated peak flow of 11,066 m^3/s (390.8 kcfs) occurred on 11 June 2010 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 5.85 m (19.2 ft) on 9 June 2010, and the highest observed stage was 4.45 m (14.6 ft) on 12 June 2010.

Chart 14 shows the relative filling of Arrow and Grand Coulee during the filling period and compares the regulation to guidelines provided in Chart 6 of the Columbia River Treaty Flood Control Operating Plan. There were no daily flood control operations specified for Arrow, and the projects were operated to meet fish flow, flood control , and refill objectives. Influenced by needs for actual operations, Arrow filled up (relative to Grand Coulee) at a faster rate than the guidelines shown on the chart.

For Duncan, a permanent change to the Storage Reservation Diagram as provided in the FCOP to deviate from flood control for the end of February from elevation 1,807.7 feet to elevation 1,812.5 feet was approved and implemented.

In operating year 2009-2010, 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 2010, the computed ICF at The Dalles was 8051 m^3/s (284.3 kcfs) based on the January forecast; 6741 m3/s (238.1 kcfs) based on the February forecast; 5663 m^3/s (188 kcfs) based on the

March forecast; 5663 m^3/s (200 kcfs) based on the April forecast; and 5333 m^3/s (200 kcfs) based on the May forecast. As mentioned earlier, the observed daily peak flow at The Dalles was 11066 m^3/s (390.8 kcfs), and occurred on 11 June 2010. Table 6 shows data for the May ICF computation.

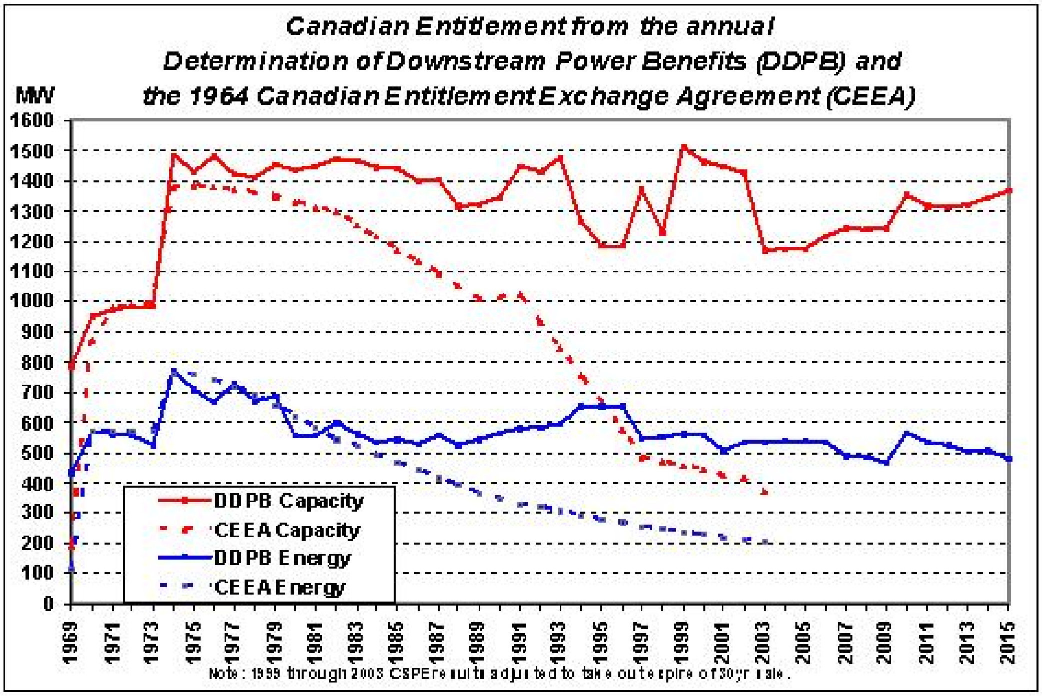
Canadian Entitlement and Downstream Power Benefits

From 1 August 2009 through 30 September 2010, 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 Canada-U.S. border. The amounts returned, not including 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 2009 through 30 September 2010, 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 1 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 1:



The CEEA estimates of the Canadian Entitlement were based on forecasted load growth that was much higher than the subsequent actual load growth, which 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).

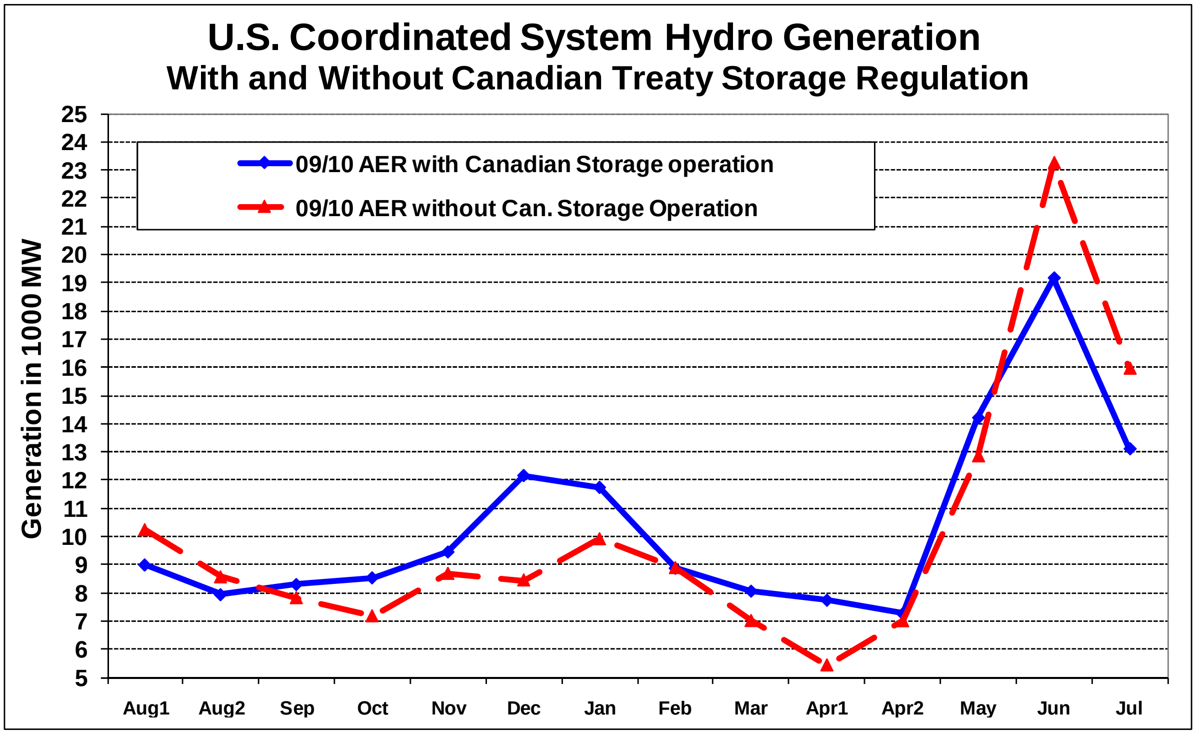
2014/2024 Review

During the period of this annual report, the Entities completed studies and published a joint report entitled “Columbia River Treaty 2014/2024 Review, Phase 1 Report, July 2010” (Phase 1 Report). The purpose of the Phase 1 Report is to provide information about post-2024 conditions both with and without the current Treaty and from the limited perspective of the two primary purposes of the Treaty – power and flood control. The Phase 1 report was released to the public on 30 July 2010, following months of extensive reviews, discussions, Entity and Coordinator meetings, and outreach meetings with stakeholders and State Department personnel. Non-disclosure agreements were prepared and signed with several parties for sharing of controlled, commercially-sensitive Canadian data and results, and letters exchanged with U.S. Departments, a state governor, and many Tribal authorities.

Power Generation and Other Accomplishments

Actual U.S. power benefits from the operation of CRT storage are unknown and can only be roughly estimated. Treaty storage has such a large impact on the U.S. system operation that its absence would significantly affect operating procedures, non-power requirements, loads and resources, and market conditions, thus making any benefit analysis highly speculative. Figure 2 shows a rough estimate of the average monthly impact on downstream U.S. power generation during the 2009-2010 operating year, with and without the regulation of Canadian storage, based on the PNCA Actual Energy Regulation (AER) that includes minimum flow and spill requirements for U.S. 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 340 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 2:



Based on the authority from the 2008-2009 and 2009-2010 DOPs, the CRTOC completed supplemental operating agreements, described in section III Operating Arrangements, which resulted in power and other benefits both in Canada and the U.S. Other benefits include changes to stream flows below Arrow that enhanced trout and mountain whitefish spawning in Canada and the downstream migration of salmon in the U.S.

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, where Arrow was drafted twice beginning early September, and a second draft in late November.

Figure 3 compares the actual operation of the composite Canadian storage to the results of the DOP TSR study.

Figure 3:

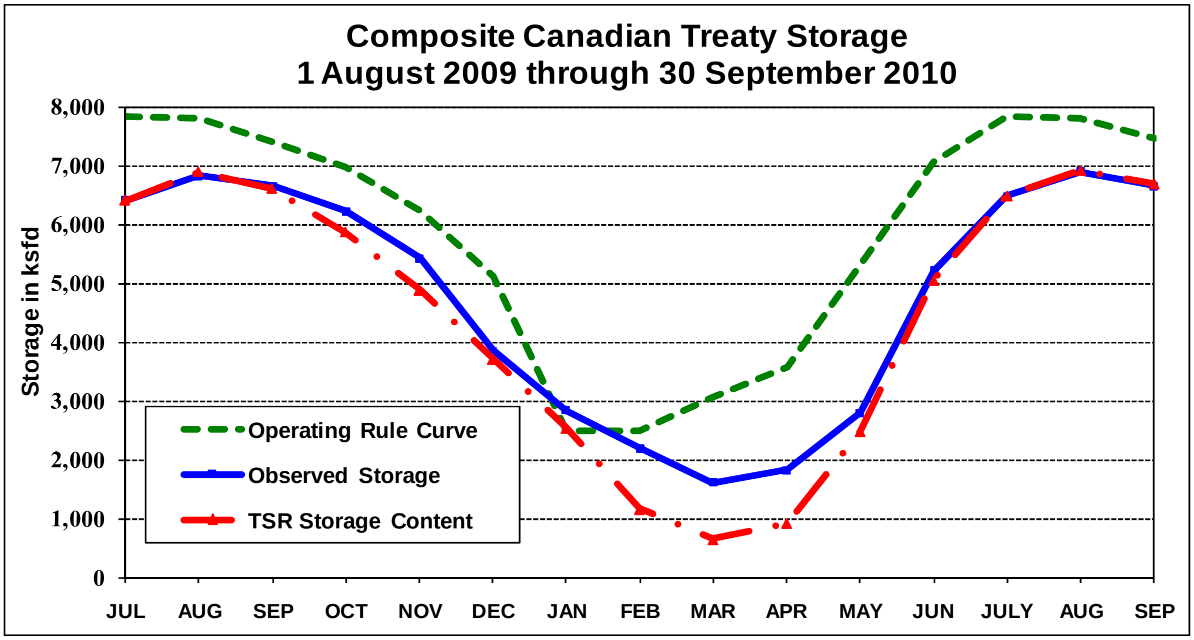


Figure 4 shows the difference in Arrow plus Duncan regulated outflows in the DOP TSR, and the actual daily CRT outflows due to the agreements. The daily unregulated stream flow is also shown for comparison purposes.

The large one day increase in Arrow Treaty outflow on July 31, 2010 was necessary to avoid overfilling the Arrow Treaty storage space (7.1 Maf) at the end of the month, as determined by the Treaty Storage Regulation (TSR) study. The water released from Treaty storage was concurrently stored under the Summer Storage agreement. This accounting mechanism provided an effective and efficient solution to addressing the highly variable Arrow flows in excess of 70 kcfs that would otherwise be experienced and which may have caused detrimental environmental impacts. This one day storage of 24 ksfd was subsequently released the following week over a longer 7-day period resulting in more acceptable Arrow physical flows of 46.4 kcfs average over the 31 July 31 – 6 Aug Treaty week.

There was no energy associated with this water transaction. While this differs from the general energy accounting principles laid out under the 2010 Summer Storage Agreement, section 2 of this agreement allowed for these changes by mutual consent of the parties.

Figure 4

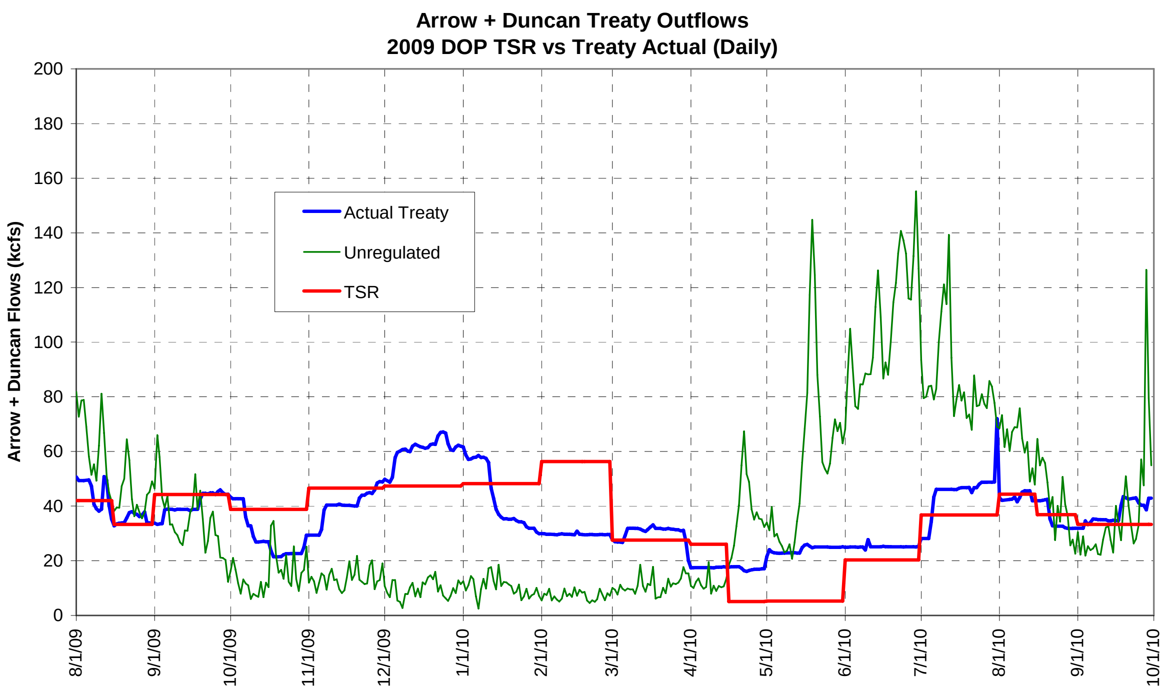


Figure 5 summarizes the Treaty accounting including supplementary operating agreements throughout the year. Section I shows the difference for each period between the final TSR composite storage and the actual Treaty composite storage, including the supplementary agreements. Section II shows the storage 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 11.

Figure 5

Summary of Treaty Storage Operations
July 2009 through July 2010

All units in KSFD	**2009**							**2010**										
I. Composite Treaty Storage (ksfd)	**JUL**	**AU1**	**AU2**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**AP1**	**AP2**	**MAY**	**JUN**	**JUL**	**AU1**	**AU2**	**SEP**
1)Treaty Storage Regulation (Final)	**6408.8**	**6722.0**	**6893.5**	**6607.9**	**5870.1**	**4878.8**	**3707.2**	**2537.3**	**1159.9**	**647.5**	**426.7**	**925.2**	**2482.7**	**5046.9**	**6479.6**	**6764.9**	**6845.9**	**6956.2**
2) Actual Treaty Content (w/SOA's)	6413.2	6677.5	6819.4	6649.5	6222.0	5425.1	3851.5	2836.1	2198.5	1601.0	1508.0	1819.5	2794.8	5210.7	6480.9	6788.0	6887.8	6871.8
3) % full (actual Treaty/7814.6 ksfd)	82.0%	86.0%	88.2%	84.5%	75.1%	62.4%	47.4%	32.5%	14.8%	8.3%	5.5%	11.8%	31.8%	64.6%	82.9%	86.5%	87.6%	89.0%
4) Final deviation from TSR	**4.4**	**-44.5**	**-74.1**	**41.6**	**351.9**	**546.3**	**144.3**	**298.8**	**1038.6**	**953.5**	**1081.3**	**894.3**	**312.1**	**163.8**	**1.3**	**23.1**	**41.9**	**-84.4**

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

	2009							**2010**										
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)	-28.0	-56.0	-56.0	-64.0	-28.0	-4.0	-122.0	-125.0	-89.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6) Fall Storage Arrow + Mica	0.0	0.0	0.0	0.0	407.0	485.0	177.1	172.5	172.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7) Non Power Uses Flow (NPU)	0.0	0.0	0.0	0.0	0.0	0.0	120.0	331.5	504.0	504.0	504.0	504.0	504.0	504.0	0.0	0.0	0.0	0.0
8) Total	-28.0	-56.0	-56.0	-64.0	379.0	481.0	175.1	379.0	587.5	504.0	504.0	504.0	504.0	504.0	0.0	0.0	0.0	0.0
10. Inadvertent (Line 4 - Line 8)	**32.4**	**11.5**	**-18.1**	**105.6**	**-27.1**	**65.3**	**-30.8**	**-80.2**	**451.1**	**449.5**	**577.3**	**390.3**	**-191.9**	**-340.2**	**1.3**	**23.1**	**41.9**	**-84.4**

(NPU Shaping; inadvertent does not apply.)

III. Summary of TSR Results August 2009-July 2010 (Final TSR in green)
Composite Treaty Storage TSR Content (ksfd)

	2009							**2010**										2010
TSR Date	**JUL**	**AU1**	**AU2**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**AP1**	**AP2**	**MAY**	**JUN**	**JUL**	**AU1**	**AU2**	**SEP**
7-Aug-09	**6408.8**	6770.8	6981.4	6749.3	6202.2	5614.7	4791.3	2622.7	1616.8	965.3	861.8	952.8	2488.9	5418.1	7655.0			
21-Aug-09		**6722.0**	6986.9	6790.3	6097.6	5501.8	4701.2	2532.6	1527.5	965.3	861.8	952.8	2488.9	5418.1	7655.0			
10-Sep-09			**6893.5**	6663.2	5935.2	5322.9	4573.2	2404.6	1461.5	963.5	860.0	951.1	2487.1	5416.3	7653.3			
24-Sep-09				6689.7	5895.7	5154.0	4411.6	2341.7	1370.2	872.2	768.6	859.7	2395.7	5325.0	7561.9			
8-Oct-09				**6607.9**	5866.4	4948.0	4137.9	2341.7	1245.2	747.2	643.6	734.7	2270.7	5200.0	7436.9			
22-Oct-09					5871.7	4934.2	4069.8	2341.7	1201.0	703.0	599.4	690.5	2226.6	5155.8	7392.7			
6-Nov-09					**5870.1**	5005.7	4154.5	2341.7	1225.9	727.9	624.3	715.4	2251.4	5180.7	7417.6			
20-Nov-09						4904.3	4039.7	2341.7	1201.0	703.0	599.4	690.5	2226.6	5155.8	7392.7			
9-Dec-09						**4878.8**	3765.0	1743.0	1183.8	642.3	537.7	646.3	2171.5	5117.7	7392.7			
21-Dec-09							3673.4	1743.0	1183.8	642.3	537.7	646.3	2171.5	5117.7	7392.7			
13-Jan-10							**3707.2**	2433.4	1848.1	695.9	804.0	887.8	2988.7	5450.9	7289.3			
25-Jan-10								2547.1	1848.1	693.1	803.9	888.7	2984.4	5443.0	7267.4			
10-Feb-10								**2537.3**	1309.6	799.1	849.5	1230.4	3473.3	5377.2	7117.1			
22-Feb-10									1210.7	925.9	924.1	1294.7	3486.8	5382.9	7121.0			
10-Mar-10									**1159.9**	587.7	542.2	911.0	2977.0	5072.4	6829.8			
24-Mar-10										582.0	519.3	858.0	2891.1	4843.1	6738.7			
12-Apr-10										**647.5**	521.7	880.4	2709.9	4624.9	6682.8			
26-Apr-10											**426.7**	886.9	2955.6	4768.4	6712.7			
12-May-10												**925.2**	2896.4	5015.8	6763.3			
24-May-10													2538.3	4743.5	6784.3			
10-Jun-10													**2482.7**	5124.0	6602.1			
24-Jun-10														4944.9	6522.4	6857.0	7057.6	
14-Jul-10														**5046.9**	6484.9	6797.9	7000.4	
26-Jul-10															6498.9	6792.9	6995.0	6795.9
6-Aug-10															**6479.6**	6773.5	6942.6	6842.2
27-Aug-10																**6764.9**	6910.7	6682.5
10-Sep-10																	**6845.9**	6533.4
23-Sep-10																		6764.3
7-Oct-10																		**6956.2**

At the beginning of the 2009-2010 operating year (July 31st), the TSR storage level for Canadian storage and the actual Canadian Treaty storage were both 82.0 percent full. Under terms of the LCA, Canada released 68.5 hm^3 (28 ksfd) in July over one week of LCA provisional draft.

In early August and mid September, under terms of the LCA, Canada released an additional 137 hm^3 (56 ksfd) of LCA provisional draft. This was stored back over two weeks in late September through early October, and one week in late November completing the first cycle.

Beginning in October and continuing into early November, the U.S. and Canada implemented a Fall Storage agreement to provisionally store above TSR levels by up to 1187 hm^3 (485 ksfd). Also in November, the U.S. and Canada reached agreement to shape flows from December through July to meet multiple system requirements and fishery needs under a Non-Power Uses Agreement. Canada exercised its LCA provisional draft rights for a second cycle December and drafted 306 hm^3 (125 ksfd) below TSR on 1 January 2010, with return of the provisional draft in mid-February and March. BC released their entire share of Fall Storage across the month of December while the U.S. released only one week for a total of 753 hm^3 (307.9 ksfd) in December.

In the last week of December through February 2010, the Non-Power Uses Agreement was utilized to store the additional water. The U.S. stored a total of 811 hm^3 (331.5 ksfd) of water for flow augmentation in Mica by the end of January. This resulted in an Arrow discharge reduction during January from 1529 m^3/s (54.2 kcfs) to 680 m^3/s (24.0 kcfs) for whitefish spawning. The storage level above TSR reached 732 hm^3 (299 ksfd) in January as storage was being managed to maintain smooth flow patterns for whitefish in January, to retain fall storage, and to store flow augmentation. In February, 422 hm^3 (172.5 ksfd) of fall provisional storage was released and restored as flow augmentation. It was mutually agreed to release the 422 hm^3 (172.5 ksfd) in March as needed to smooth flows. Arrow actual outflows were maintained at 683 m^3/s (24.0 kcfs) in February to balance the needs of Canadian trout spawning and whitefish. The storage level above TSR was increased to 2542 hm^3 (1039 ksfd) in February as the remaining flow augmentation was stored and LCA returned. With fall storage released, and LCA provisional draft returned by the end of March, the Canadian storage ended the month 2334 hm^3 (954 ksfd) above the TSR level; only the flow augmentation storage remained. Mica was able to maintain this storage for fish requirements April through June. Monthly average outflows at Arrow increased from 428 m^3/s (15.1 kcfs) in April to 614 m^3/s (21.7 kcfs) in June to balance the needs of B.C. trout spawning, U.S. fisheries, and system load requirements. Flow augmentation was released in July 2010 as inflows receded rapidly, and outflows needed to be maintained at a uniform or greater amount.

In June 2010, there was storage under the 2010 Summer Storage Agreement (Not Treaty) for three weeks. This resulted in Arrow actual outflows lower than Arrow Treaty outflows by 142 m3/s (5 kcfs) for a total of 245 hm^3 (100 ksfd) to be released mainly in August over three weeks.

The sum of Canadian storage at the end of July was slightly above DOP TSR amounts by 3.1 hm^3 (1.3 ksfd). To avoid over fill at Arrow on July 31, it was mutually agreed to store an additional 59 hm3 (24 ksfd) under the 2010 Summer Storage Agreement for 31 July and release this same amount the following week.

Differences between Arrow actual and Treaty outflows were mainly due to shaping under two Summer Storage Agreements. This use of non-Treaty storage is separate from and not related to the 1990 NTSA. The U.S. returned over one week in late August through early September 2009 the remaining storage under the 2009 Summer Storage Agreement. In early June 2010, a total of 100 ksfd was stored under the 2010 Summer Storage Agreement to help reduce inflow during the peak freshet period to shape for fisheries later in the summer and enhance summer recreation. This resulted in the actual Arrow outflows to be higher by 113 m^3/s (4 kcfs) for the week 29 August through 4 September 2010.

August 2010 outflows were increased on average by 99 m3/s (3.5 kcfs), to help smooth flows and aid in fish requirements downstream. Late September rain storms in Canada resulted in high Arrow outflows with an opportunity to store additional Non Treaty under the 1990 NTSA.

VII – TABLES

Table 1: Most Probable 1-April through 31-August Forecasts

Runoff Volume Forecasts in Cubic Kilometers

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.50	27.93	13.77	7.05	94.61
February	2.42	26.90	13.31	6.76	84.49
March	2.25	25.45	12.80	6.27	76.60
April	2.24	24.76	12.76	6.29	75.12
May	2.24	24.36	12.55	6.03	76.72
June	2.19	23.26	12.11	5.44	80.79
Actual	2.00	22.30	11.39	5.58	95.49

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

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.03	22.64	11.16	5.71	76.70
February	1.96	21.81	10.79	5.48	68.50
March	1.83	20.63	10.38	5.08	62.10
April	1.82	20.08	10.34	5.10	60.90
May	1.81	19.75	10.18	4.89	62.20
June	1.78	18.86	9.81	4.41	65.50
Actual	1.62	18.08	9.23	4.52	77.41

Table 2M (metric): 2010 Mica Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			11.5	11.1	10.9	10.2	9.5	7.7
PROBABLE DATE-31JULY INFLOW, hm3	**		11508.8	11050.8	10869.8	10205.0	9491.3	7670.1
95% FORECAST ERROR FOR DATE, hm3			1804.7	1276.1	1115.1	1028.3	982.9	970.5
95% CONF.DATE-31JULY INFLOW, hm3	1/		9704.1	9774.7	9754.7	9176.7	8508.4	6699.6
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		9703.9					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		6410.1					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		5340.7					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		0.0					
JAN31 ORC, m	7/		741.5					
BASE ECC, m	8/	741.5						
LOWER LIMIT, m		732.0						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		9509.9	9579.2				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		6204.6	6204.6				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		5329.2	5259.9				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		0.0	0.0				
FEB28 ORC, m	7/		741.4	741.4				
BASE ECC, m	8/	741.4						
LOWER LIMIT, m		730.0						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		9277.0	9344.5	9520.7			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0			
MIN APR1-JUL31 OUTFLOW, hm3	4/		5334.6	5267.0	5090.9			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		4071.6	4071.6	4071.6			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		0.0	0.0	0.0			
MAR31 ORC, m	7/		740.2	740.4	741.5			
BASE ECC, m	8/	741.4						
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/		8801.6	8865.7	9023.1	8699.4		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		5756.8	5756.8	5756.8	5756.8		
VRC APR30 RESERVOIR CONTENT, hm3	5/		5589.7	5525.6	5368.3	5692.0		
VRC APR30 RESERVOIR CONTENT, METERS	6/		0.0	0.0	0.0	0.0		
APR30 ORC, m	7/		740.2	740.4	741.5	740.2		
BASE ECC, m	8/	745.8						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		6967.4	7018.3	7140.4	6882.5	6730.1	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		962.8	962.8	962.8	962.8	962.8	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		5529.3	5529.3	5529.3	5529.3	5529.3	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		7196.4	7145.5	7023.5	7281.3	7433.7	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		0.0	0.0	0.0	0.0	0.0	
MAY31 ORC, m	7/		744.7	744.8	745.8	744.7	744.7	
BASE ECC, m	8/	752.9						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		3532.2	3558.1	3609.2	3477.8	3403.5	3390.0
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		1132.7	1132.7	1132.7	1132.7	1132.7	1132.7
MIN JUL1-JUL31 OUTFLOW, hm3	4/		3033.8	3033.8	3033.8	3033.8	3033.8	3033.8
VRC JUN30 RESERVOIR CONTENT, hm3	5/		8136.2	8110.2	8056.7	8190.5	8264.9	8278.3
VRC JUN30 RESERVOIR CONTENT, METERS	6/		0.0	0.0	0.0	0.0	0.0	0.0
JUN30 ORC, m	7/		751.2	751.2	751.5	751.6	751.2	751.2
BASE ECC, m	8/	752.9						
JUL 31 ORC, m			2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

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 2: 2010 Mica Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			9343.1	9014.9	8485.3	8223.5	7576.9	5944.5
PROBABLE DATE-31JULY INFLOW, KSFD	**		4710.5	4545.0	4278.0	4146.0	3820.0	2997.0
95% FORECAST ERROR FOR DATE, KSFD			737.7	521.6	455.8	420.3	401.7	396.7
95% CONF.DATE-31JULY INFLOW, KSFD	1/		3872.8	4023.4	3822.2	3725.7	3418.3	2600.3
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		3972.8					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		2222.4					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1778.8					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2435.0					
JAN31 ORC, FT	7/		2435.0					
BASE ECC, FT	8/	2436.2						
LOWER LIMIT, FT		2403.1						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		3983.4	3942.9				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		2138.4	2173.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1774.2	1759.3				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2439.9	2434.6				
FEB28 ORC, FT	7/		2439.9	2434.6				
BASE ECC, FT	8/	2435.9						
LOWER LIMIT, FT		2396.9						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		3798.0	3846.4	3730.5			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		2045.4	2080.0	2080.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1776.6	1762.8	1878.7			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2434.9	2434.7	2437.1			
MAR31 ORC, FT	7/		2435.0	2434.7	2436.1			
BASE ECC, FT	8/	2436.1						
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/		3603.4	3649.2	3535.6	3532.0		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1955.4	1990.0	1990.0	1990.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1881.3	1870.0	1983.6	1987.2		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2437.2	2436.9	2439.3	2439.4		
APR30 ORC, FT	7/		2435.4	2436.9	2437.9	2437.9		
BASE ECC, FT	8/	2437.9						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		2852.5	2888.8	2797.9	2794.3	2703.8	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		25000.0	25000.0	25000.0	25000.0	25000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		1862.4	1897.0	1897.0	1897.0	1897.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2539.1	2537.4	2628.3	2631.9	2722.4	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2450.8	2450.8	2452.6	2452.7	2452.4	
MAY31 ORC, FT	7/		2442.9	2442.9	2442.9	2442.9	2442.9	
BASE ECC, FT	8/	2438.7						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1446.1	1564.5	1414.2	1412.0	1367.3	1315.8
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		37000.0	37000.0	37000.0	37000.0	37000.0	37000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		1129.4	1147.0	1147.0	1147.0	1147.0	1147.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3212.5	3211.7	3262.0	3264.2	3308.9	3360.4
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2464.1	2464.0	2464.9	2465.0	2465.9	2466.9
JUN30 ORC, FT	7/		2464.0	2464.0	2464.3	2464.3	2464.3	2464.3
BASE ECC, FT	8/	2464.3						
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): 2010 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	23.7	21.8	20.7	18.6	13.6
& IN hm3	**		24579.5	23710.0	21833.5	20654.2	18640.6	13578.6
95% FORECAST ERROR FOR DATE, IN hm3			3626.0	2680.3	2333.4	1982.3	1767.6	1660.2
95% CONF.DATE-31JULY INFLOW, hm3	1/		20953.4	21029.8	19500.1	18672.0	16873.0	11918.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		20953.4					
MIN FEB1-JUL31 OUTFLOW, hm3	3/		9241.5					
UPSTREAM DISCHARGE, hm3	4/		4282.5					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		1328.5					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		423.8					
JAN31 ORC, m	7/		423.2					
BASE ECC, m	8/	428.8						
LOWER LIMIT, m		422.1						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		20471.7	20546.1				
MIN MAR1-JUL31 OUTFLOW, hm3	3/		8899.0	9111.1				
UPSTREAM DISCHARGE, hm3	4/		4293.8	4330.2				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		1479.0	1653.2				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		424.2	424.6				
FEB28 ORC, m	7/		424.2	424.6				
BASE ECC, m	8/	427.6						
LOWER LIMIT, m		420.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		19863.9	19936.1	18934.5			
MIN APR1-JUL31 OUTFLOW, hm3	3/		8519.8	8731.9	8731.9			
UPSTREAM DISCHARGE, hm3	4/		4287.9	4321.7	4160.9			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		1701.6	1875.3	2716.2			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		424.8	425.2	427.3			
MAR31 ORC, m	7/		424.8	425.2	427.3			
BASE ECC, m	8/	428.1						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.9	87.9	90.1	92.8		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		18418.2	18484.8	17569.5	17327.6		
MIN MAY1-JUL31 OUTFLOW, hm3	3/		8152.8	8364.9	8364.9	8364.9		
UPSTREAM DISCHARGE, hm3	4/		4242.6	4059.4	3945.1	3945.1		
VRC APR30 RESERVOIR CONTENT, hm3	5/		2735.1	2697.4	3498.4	3740.4		
VRC APR30 RESERVOIR CONTENT, METERS	6/		427.3	427.2	429.2	429.7		
APR30 ORC, Fm	7/		427.3	427.2	429.2	429.5		
BASE ECC, m	8/	429.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		13682.6	13732.5	13045.5	12865.0	12536.6	
MIN JUN1-JUL31 OUTFLOW, hm3	3/		7773.6	7985.7	7985.7	7985.7	7985.7	
UPSTREAM DISCHARGE, hm3	4/		3366.8	3366.8	3366.8	3366.8	3366.8	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		6215.6	6377.8	7064.8	7245.4	7573.7	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		435.1	435.4	436.8	437.2	437.8	
MAY31 ORC, m	7/		434.9	435.4	436.6	436.6	436.6	
BASE ECC, m	8/	436.6						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		6390.8	6414.0	6103.5	6012.3	5871.8	5577.8
MIN JUL1-JUL31 OUTFLOW, hm3	3/		3966.7	4095.6	4095.6	4095.6	4095.6	4095.6
UPSTREAM DISCHARGE, hm3	4/		774.8	776.8	739.1	739.1	739.1	739.1
VRC JUN30 RESERVOIR CONTENT, hm3	5/		7317.3	7436.7	7489.0	7580.3	7720.7	8014.8
VRC JUN30 RESERVOIR CONTENT, METERS	6/		437.4	437.6	437.7	437.8	438.1	438.7
JUN30 ORC, m	7/		437.2	437.2	437.4	437.2	437.3	437.2
BASE ECC, m	8/	439.1						
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 (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 3: 2010 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			19926.7	19221.8	17700.5	16744.5	15112.1	11008.3
& IN KSFD	**		10046.4	9691.0	8924.0	8442.0	7619.0	5550.0
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/		8564.3	8595.5	7970.3	7631.8	6896.5	4871.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		8564.3					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		3777.3					
UPSTREAM DISCHARGE, KSFD	4/		1750.4					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		543.0					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1390.4					
JAN31 ORC, FT	7/		1388.3					
BASE ECC, FT	8/	1406.7						
LOWER LIMIT, FT		1384.9						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		8367.4	8397.8				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		3637.3	3724.0				
UPSTREAM DISCHARGE, KSFD	4/		1755.0	1769.9				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		604.5	675.7				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1391.7	1393.2				
FEB28 ORC, FT	7/		1391.7	1393.2				
BASE ECC, FT	8/	1402.9						
LOWER LIMIT, FT		1379.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		8119.0	8148.5	7739.1			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		3482.3	3569.0	3569.0			
UPSTREAM DISCHARGE, KSFD	4/		1752.6	1766.4	1700.7			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		695.5	766.5	1110.2			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1393.6	1395.0	1401.9			
MAR31 ORC, FT	7/		1393.6	1395.0	1401.9			
BASE ECC, FT	8/	1404.5						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.9	87.9	90.1	92.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		7528.1	7555.3	7181.2	7082.3		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		3332.3	3419.0	3419.0	3419.0		
UPSTREAM DISCHARGE, KSFD	4/		1734.1	1659.2	1612.5	1612.5		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1117.9	1102.5	1429.9	1528.8		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1402.0	1401.7	1408.0	1409.8		
APR30 ORC, FT	7/		1402.0	1401.7	1408.0	1409.2		
BASE ECC, FT	8/	1409.2						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		5592.5	5612.9	5332.1	5258.3	5124.1	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		3177.3	3264.0	3264.0	3264.0	3264.0	
UPSTREAM DISCHARGE, KSFD	4/		1376.1	1376.1	1376.1	1376.1	1376.1	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2540.5	2606.8	2887.6	2961.4	3095.6	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1427.5	1428.6	1433.2	1434.3	1436.5	
MAY31 ORC, FT	7/		1426.9	1428.6	1432.4	1432.4	1432.4	
BASE ECC, FT	8/	1432.4						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		2612.1	2621.6	2494.7	2457.4	2400.0	2279.8
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		1621.3	1674.0	1674.0	1674.0	1674.0	1674.0
UPSTREAM DISCHARGE, KSFD	4/		316.7	317.5	302.1	302.1	302.1	302.1
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2990.8	3039.6	3061.0	3098.3	3155.7	3275.9
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1434.9	1435.6	1435.9	1436.5	1437.4	1439.3
JUN30 ORC, FT	7/		1434.3	1434.4	1435.0	1434.5	1434.6	1434.5
BASE ECC, FT	8/	1440.7						
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): 2010 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	2.1	1.9	1.9	1.7	1.3
& IN hm3	**		2145.7	2106.5	1932.8	1871.6	1715.1	1282.0
95% FORECAST ERROR FOR DATE, IN hm3			309.7	256.1	256.1	231.3	210.6	190.0
95% CONF.DATE-31JULY INFLOW, hm3	1/		1861.4	1850.4	1676.7	1640.4	1504.4	1092.2
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		1861.4					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		202.6					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		425.6					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		556.3					
JAN31 ORC, m	7/		556.3					
BASE ECC, m	8/	564.3						
LOWER LIMIT, m		553.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.1	98.1				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		1825.9	1815.4				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		195.7	225.3				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		96.6	136.8				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		549.5	550.5				
FEB28 ORC, m	7/		549.5	550.5				
BASE ECC, m	8/	557.9						
LOWER LIMIT, m		548.2						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.7	95.7	97.6			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		1781.4	1770.8	1636.5			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8			
MIN APR1-JUL31 OUTFLOW, hm3	4/		188.1	217.7	217.7			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		133.6	173.7	308.0			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		550.4	551.3	554.1			
MAR31 ORC, m	7/		550.4	551.3	554.1			
BASE ECC, m	8/	558.5						
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/		1669.6	1659.8	1536.0	1538.7		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8	2.8		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		180.8	210.4	210.4	210.4		
VRC APR30 RESERVOIR CONTENT, hm3	5/		238.1	280.9	401.2	398.6		
VRC APR30 RESERVOIR CONTENT, METERS	6/		552.7	553.6	555.9	555.8		
APR30 ORC, m	7/		551.0	552.0	555.4	555.6		
BASE ECC, m	8/	559.6						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.5	67.5	69.0	70.6	75.3	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		1256.3	1249.0	1157.0	1158.2	1132.8	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8	2.8	2.8	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		173.2	202.8	202.8	202.8	202.8	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		643.7	790.5	790.5	790.5	796.9	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		560.2	562.6	562.6	562.6	562.8	
MAY31 ORC, m	7/		560.2	562.6	562.6	562.6	562.8	
BASE ECC, m	8/	565.9						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			32.5	32.5	33.3	34.0	36.3	48.2
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		605.0	601.4	558.3	557.8	546.1	526.3
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		17.0	22.7	22.7	22.7	22.7	22.7
MIN JUL1-JUL31 OUTFLOW, hm3	4/		127.0	144.1	144.1	144.1	144.1	144.1
VRC JUN30 RESERVOIR CONTENT, hm3	5/		1359.1	1464.0	1464.0	1464.0	1464.0	1464.0
VRC JUN30 RESERVOIR CONTENT, METERS	6/		571.4	572.9	572.9	572.9	572.9	572.9
JUN30 ORC, m	7/		571.4	571.4	571.4	571.4	571.4	571.4
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 (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 4: 2010 Duncan Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			1739.5	1707.8	1566.9	1517.4	1390.4	1039.3
& IN KSFD	**		877.0	861.0	790.0	765.0	701.0	524.0
95% FORECAST ERROR FOR DATE, IN KSFD			126.6	104.7	104.7	94.5	86.1	77.6
95% CONF.DATE-31JULY INFLOW, KSFD	1/		760.8	756.3	685.3	670.5	614.9	446.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		760.8					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		82.8					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		173.9					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1825.2					
JAN31 ORC, FT	7/		1825.2					
BASE ECC, FT	8/	1851.4						
LOWER LIMIT, FT		1816.6						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.1	98.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		746.3	742.0				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		80.0	92.1				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		39.5	55.9				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1802.9	1806.0				
FEB28 ORC, FT	7/		1802.9	1806.0				
BASE ECC, FT	8/	1830.4						
LOWER LIMIT, FT		1798.6						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.7	95.7	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		728.1	723.8	668.9			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		76.9	89.0	89.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		54.6	71.0	125.9			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1805.8	1808.7	1817.9			
MAR31 ORC, FT	7/		1805.8	1808.7	1817.9			
BASE ECC, FT	8/	1832.4						
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/		682.4	678.4	627.8	628.9		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0	100.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		73.9	86.0	86.0	86.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		97.3	114.8	164.0	162.9		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1813.2	1816.2	1823.7	1823.5		
APR30 ORC, FT	7/		1807.8	1811.0	1822.1	1822.7		
BASE ECC, FT	8/	1836.0						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.5	67.5	69.0	70.6	75.3	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		513.5	510.5	472.9	473.4	463.0	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0	100.0	100.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		70.8	82.9	82.9	82.9	82.9	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		263.1	323.1	323.1	323.1	325.7	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1837.9	1845.9	1845.9	1845.9	1846.3	
MAY31 ORC, FT	7/		1837.9	1845.9	1845.9	1845.9	1846.3	
BASE ECC, FT	8/	1856.6						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			32.5	32.5	33.3	34.0	36.3	48.2
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		247.3	245.8	228.2	228.0	223.2	215.1
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		600.0	800.0	800.0	800.0	800.0	800.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		51.9	58.9	58.9	58.9	58.9	58.9
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		555.5	598.4	598.4	598.4	598.4	598.4
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1874.7	1879.7	1879.7	1879.7	1879.7	1879.7
JUN30 ORC, FT	7/		1874.7	1874.7	1874.7	1874.7	1874.7	1874.7
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): 2010 Libby Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			7.1	6.8	6.3	6.3	6.1	5.5
PROBABLE DATE-31JULY INFLOW, hm3			7115.9	6810.1	6265.0	6294.6	6051.4	5519.8
95% FORECAST ERROR FOR DATE, hm3			1593.7	1195.2	1118.8	1084.3	980.6	941.2
OBSERVED JAN1-DATE INFLOW, IN hm3			0.0	197.4	358.9	561.3	1010.2	2161.1
95% CONF.DATE-31JULY INFLOW, hm3	1/		5522.5	5417.5	4787.3	4649.0	4060.6	2417.7
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		5351.2					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		2221.5					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		3012.5					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		730.0					
JAN31 ORC, m	7/		730.0					
BASE ECC, m	9/	738.4						
LOWER LIMIT, m		719.3						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		5196.6	5260.4				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		1947.5	1947.5				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		2893.1	2829.2				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		729.1	728.6				
FEB28 ORC, m	7/		729.1	733.3				
BASE ECC, m	9/	737.6						
LOWER LIMIT, m		711.2						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.6	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		5003.3	5065.4	4610.1			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3			
MIN APR1-JUL31 OUTFLOW, hm3	4/		1644.1	1644.1	1644.1			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		2783.0	2720.9	3176.2			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		728.2	727.6	731.3			
MAR31 ORC, m	7/		728.2	733.0	733.0			
BASE ECC, m	9/	736.8						
LOWER LIMIT, m		699.8						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.4	85.0	87.6	90.9		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		4550.4	4605.0	4193.5	4226.0		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3	113.3		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		1350.5	1350.5	1350.5	1350.5		
VRC APR30 RESERVOIR CONTENT, hm3	5/		2942.3	2887.7	3299.2	3266.7		
VRC APR30 RESERVOIR CONTENT, METERS	6/		729.4	729.0	732.2	732.0		
APR30 ORC, m	7/		729.4	735.1	735.1	735.1		
BASE ECC, m	9/	736.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.2	57.0	58.7	60.9	67.0	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		3048.2	3088.1	2810.2	2831.2	2720.6	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		169.9	169.9	169.9	169.9	169.9	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		1047.1	1047.1	1047.1	1047.1	1047.1	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		4140.9	4101.2	4379.2	4358.1	4468.7	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		737.9	737.7	739.4	739.3	740.0	
MAY31 ORC, m	7/		737.9	742.7	742.7	742.7	742.7	
BASE ECC, m	9/	742.7						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.7	20.4	21.0	21.8	24.0	35.8
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		1088.0	1105.1	1005.3	1013.4	974.5	865.6
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		226.5	226.5	226.5	226.5	226.5	226.5
MIN JUL1-JUL31 OUTFLOW, hm3	4/		606.8	606.8	606.8	606.8	606.8	606.8
VRC JUN30 RESERVOIR CONTENT, hm3	5/		5660.9	5643.8	5743.6	5735.6	5774.5	5883.3
VRC JUN30 RESERVOIR CONTENT, METERS	6/		746.9	746.8	747.3	747.3	747.5	748.1
JUN30 ORC, m	7/		746.9	749.5	749.5	749.5	749.5	749.5
BASE ECC, m	9/	749.5						
JUL 31 ORC, m			749.5	749.5	749.5	749.5	749.5	749.5
JAN1-JUL31 FORECAST,-EARLYBIRD, km3	8/		109.2	97.7	88.6	86.0	87.5	91.3

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: 2010 Libby Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE JAN-31JULY INFLOW, KAF			5769	5521	5079	5103	4906	4475
PROBABLE JAN-31JULY INFLOW, KSFD			2908.5	2783.5	2560.7	2572.8	2473.4	2256.1
95% FORECAST ERROR FOR DATE, KSFD			651.4	488.5	457.3	443.2	400.8	384.7
OBSERVED JAN1-DATE INFLOW, IN KSFD			0	80.7	146.7	229.4	412.9	883.3
95% CONF.DATE-31JULY INFLOW, KSFD	1/		2257.2	2214.3	1956.7	1900.2	1659.7	988.2
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		2187.2					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4000					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		908					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1231.3					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2395					
JAN31 ORC, FT	7/		2395					
BASE ECC, FT	9/	2422.6						
LOWER LIMIT, FT		2359.8						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		2124	2150.1				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		796	796				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1182.5	1156.4				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2391.9	2390.3				
FEB28 ORC, FT	7/		2391.9	2406				
BASE ECC, FT	9/	2420.0						
LOWER LIMIT, FT		2333.3						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.6	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		2045	2070.4	1884.3			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000	4000			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		672	672	672			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1137.5	1112.1	1298.2			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2389	2387.2	2399.3			
MAR31 ORC, FT	7/		2389	2404.8	2404.8			
BASE ECC, FT	9/	2417.2						
LOWER LIMIT, FT		2295.9						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.4	85	87.6	90.9		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		1859.9	1882.2	1714	1727.3		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000	4000	4000		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		552	552	552	552		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1202.6	1180.3	1348.5	1335.2		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2393.2	2391.8	2402.2	2401.5		
APR30 ORC, FT	7/		2393.2	2411.9	2411.9	2411.9		
BASE ECC, FT	9/	2416.2						
		2287.0						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.2	57	58.7	60.9	67	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		1245.9	1262.2	1148.6	1157.2	1112	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		6000	6000	6000	6000	6000	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		428	428	428	428	428	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		1692.5	1676.3	1789.9	1781.3	1826.5	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2421	2420.2	2425.9	2425.5	2427.7	
MAY31 ORC, FT	7/		2421	2436.6	2436.6	2436.6	2436.6	
BASE ECC, FT	9/	2436.6						
		2287.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.7	20.4	21	21.8	24	35.8
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		444.7	451.7	410.9	414.2	398.3	353.8
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		8000	8000	8000	8000	8000	8000
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		248	248	248	248	248	248
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2313.8	2306.8	2347.6	2344.3	2360.2	2404.7
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2450.5	2450.1	2451.9	2451.8	2452.5	2454.4
JUN30 ORC, FT	7/		2450.5	2458.9	2458.9	2458.9	2458.9	2458.9
BASE ECC, FT	9/	2458.9						
		2287.0						
JUL 31 ORC, FT			2459	2459	2459	2459	2459	2459
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		88.5	79.2	71.8	69.7	70.9	74

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

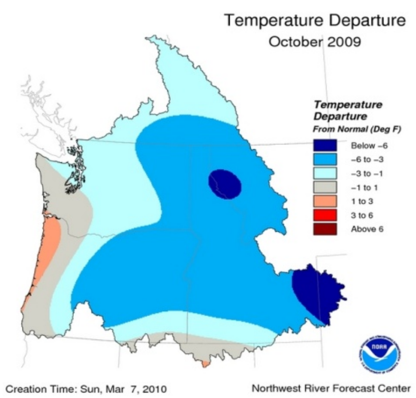
Columbia River at The Dalles, OR

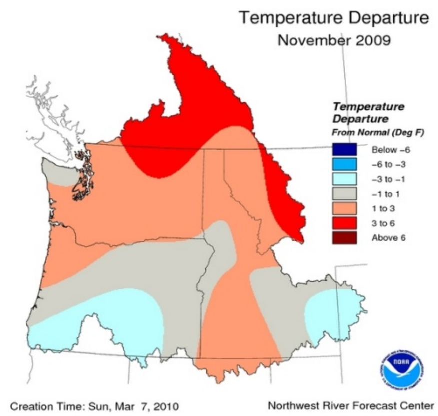
Metric and English Units, 1 May 2009

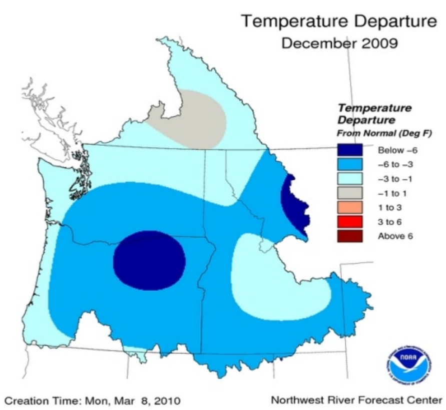
Upstream Storage Corrections in km^3 and Maf	Metric (km^3)		English (Maf)	
Mica	7.239		5.869	
Arrow	4.441		3.600	
Duncan	1.718		1.393	
Libby	2.709		2.196	
Hungry Horse	1.071		0.868	
Flathead Lake	0.617		0.500	
Noxon Rapids	0.000		0.000	
Pend Oreille Lake	0.617		0.500	
Grand Coulee	2.946		2.388	
Brownlee	0.405		0.328	
Dworshak	1.428		1.158	
John Day	0.195		0.158	
Total Upstream Storage Corrections	23.384		18.958	
1-May Forecast of TDA May – Aug Runoff Volume		85.116		69.005
Less Estimated Depletions		-2.061		-1.671
Less Total Upstream Storage Corrections		-23.384		-18.958
Forecast of Adjusted Residual Runoff Volume		59.671		48.376
Computed Initial Controlled Flow from Chart 1 of the Flood Control Operating Plan, km^3/s and kcfs		91.537		300

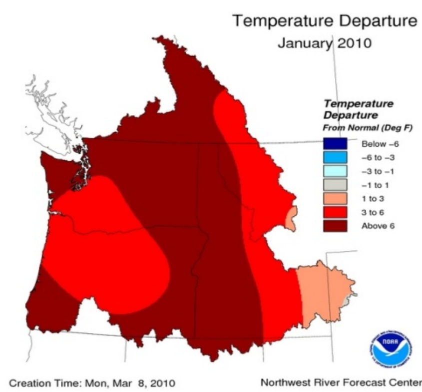
VIII - CHARTS

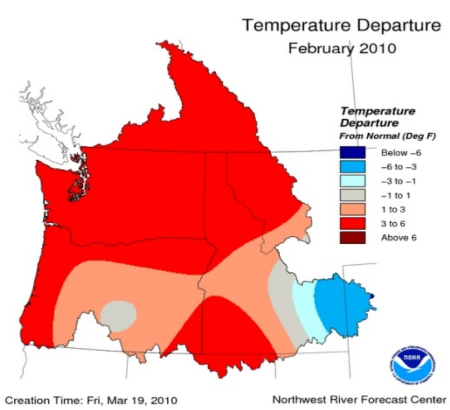
Chart 1: Pacific Northwest Monthly Temperature Departures Oct – Mar











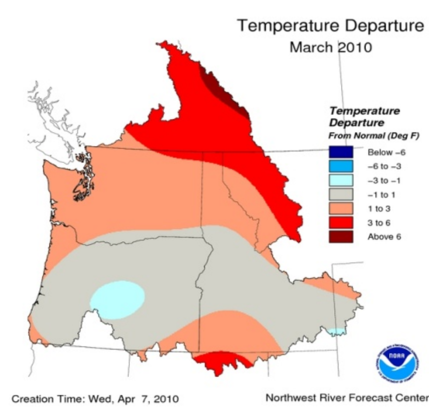


Chart 1: Pacific Northwest Monthly Temperature Departures (Continued)
April – September

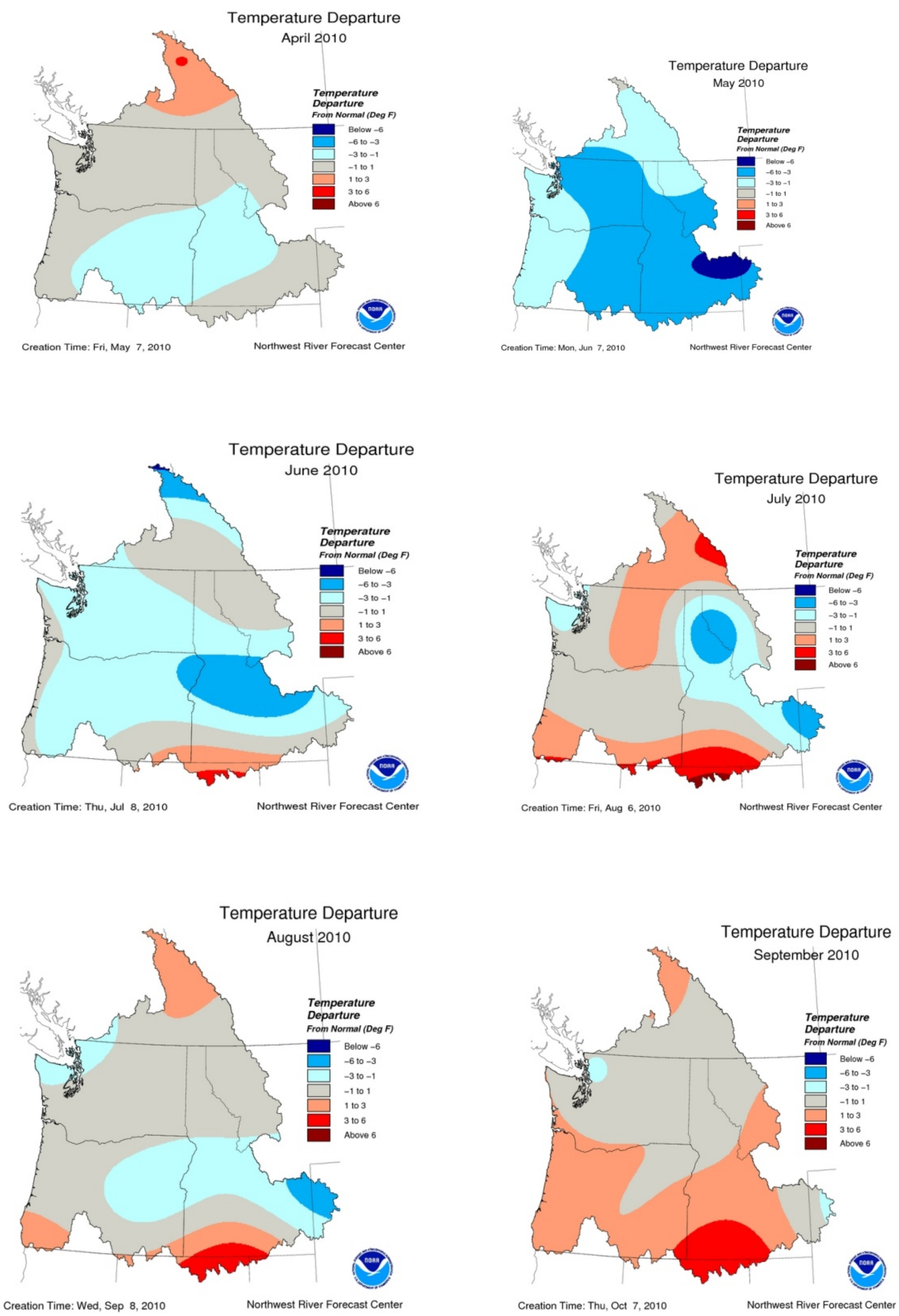


Chart 2: Seasonal Precipitation

Columbia River Basin

October 2009 – September 2010

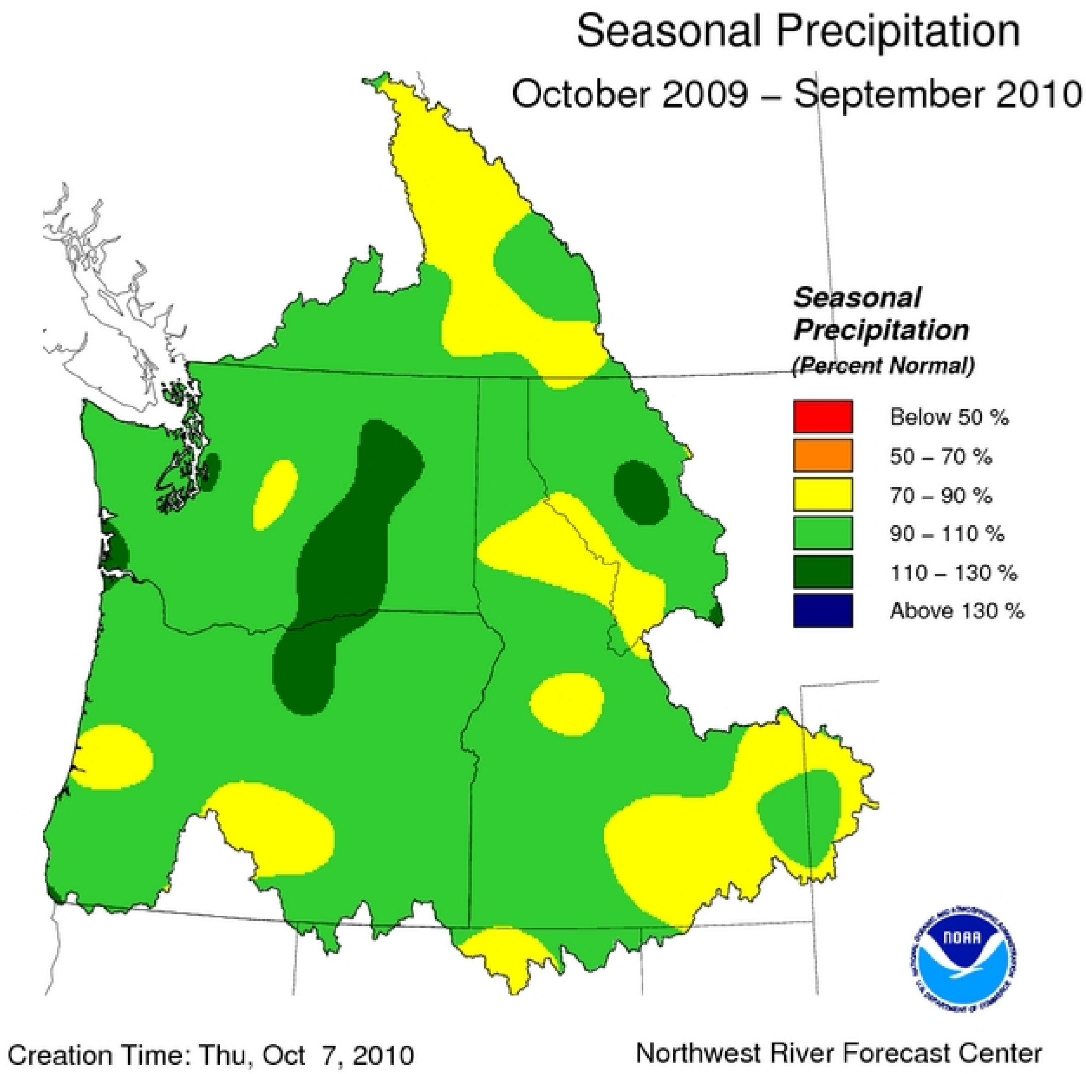
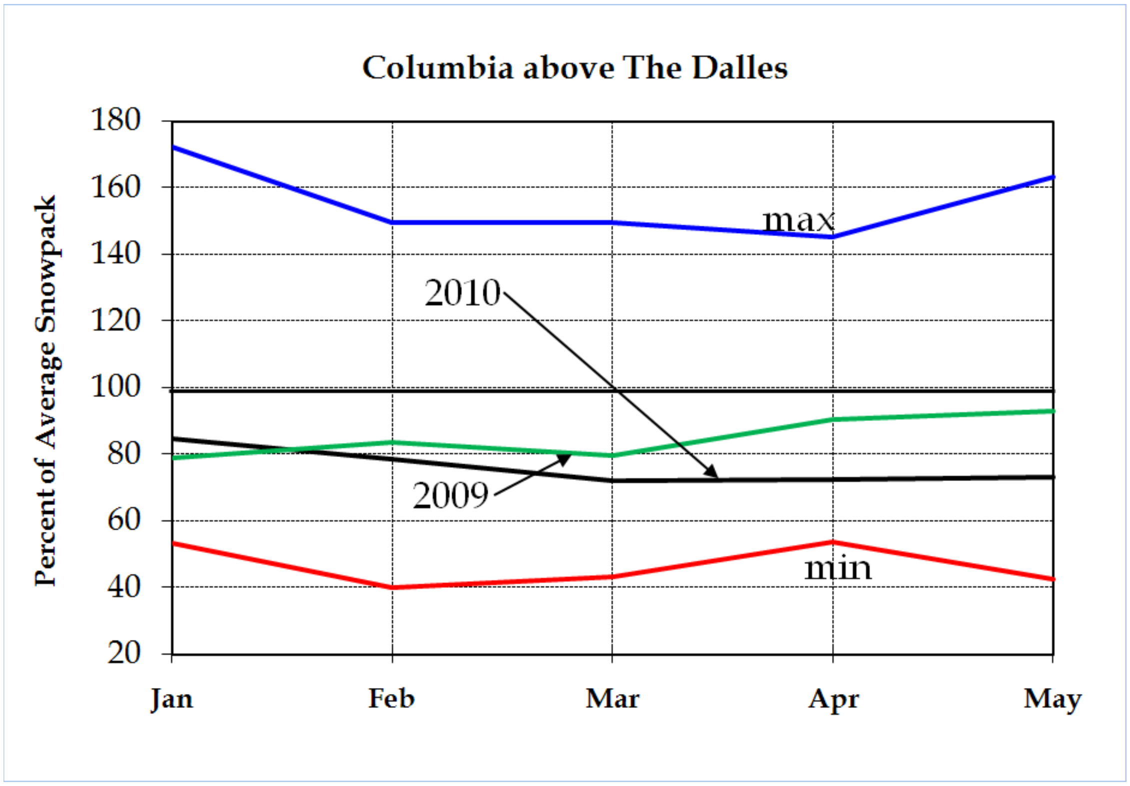


Chart 3: Columbia Basin Snowpack



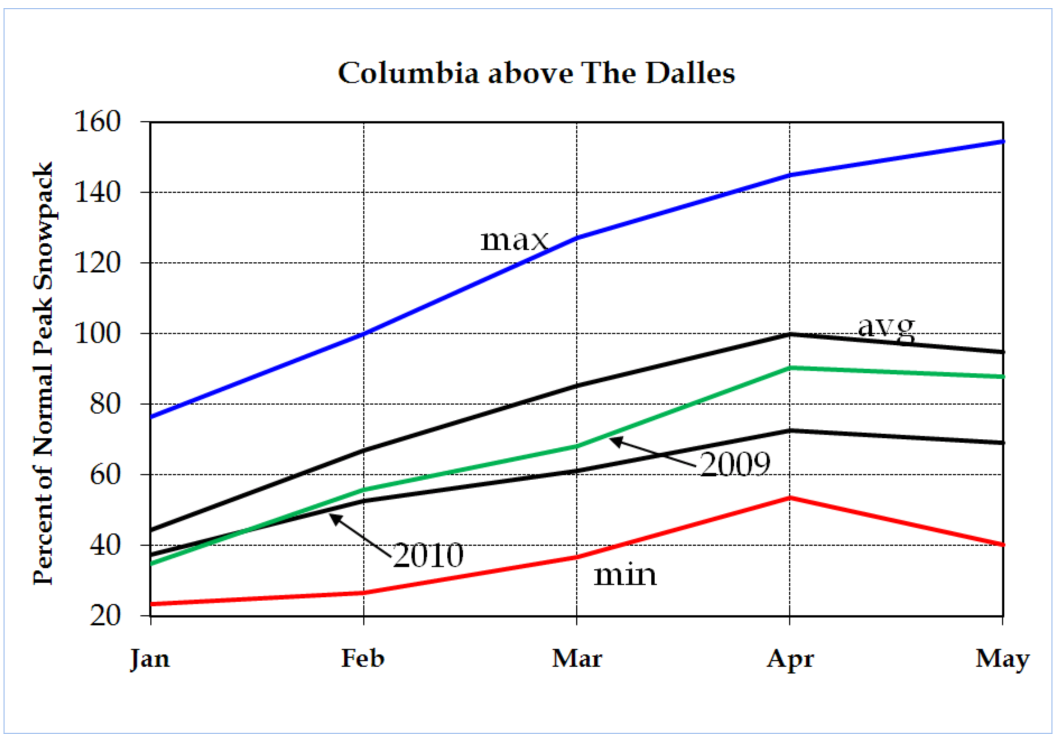


Chart 4: Accumulated Precipitation for WY 2010

At Primary Columbia River Basins

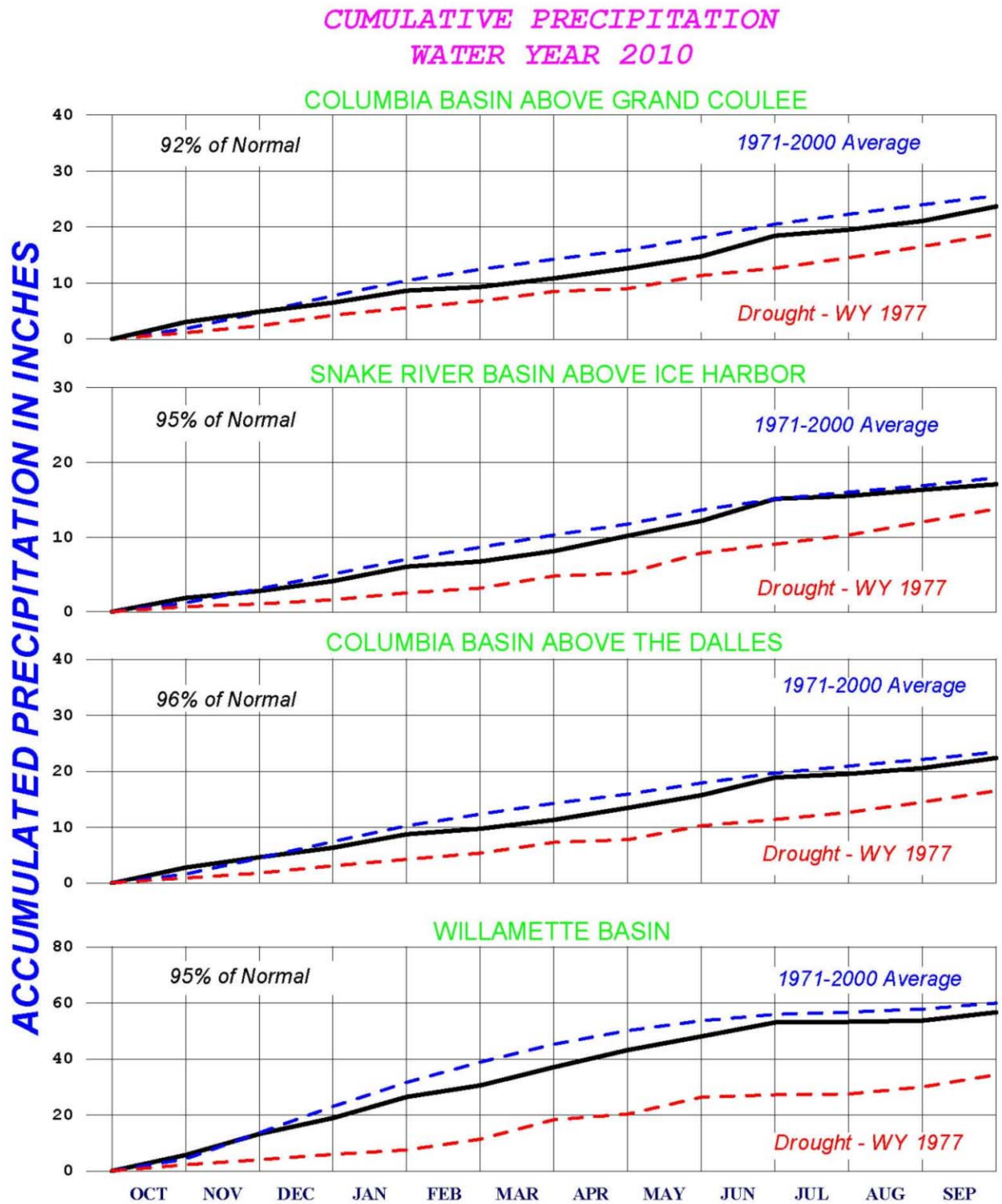


Chart 5: Regulation of Mica

1 July 2009 – September 2010

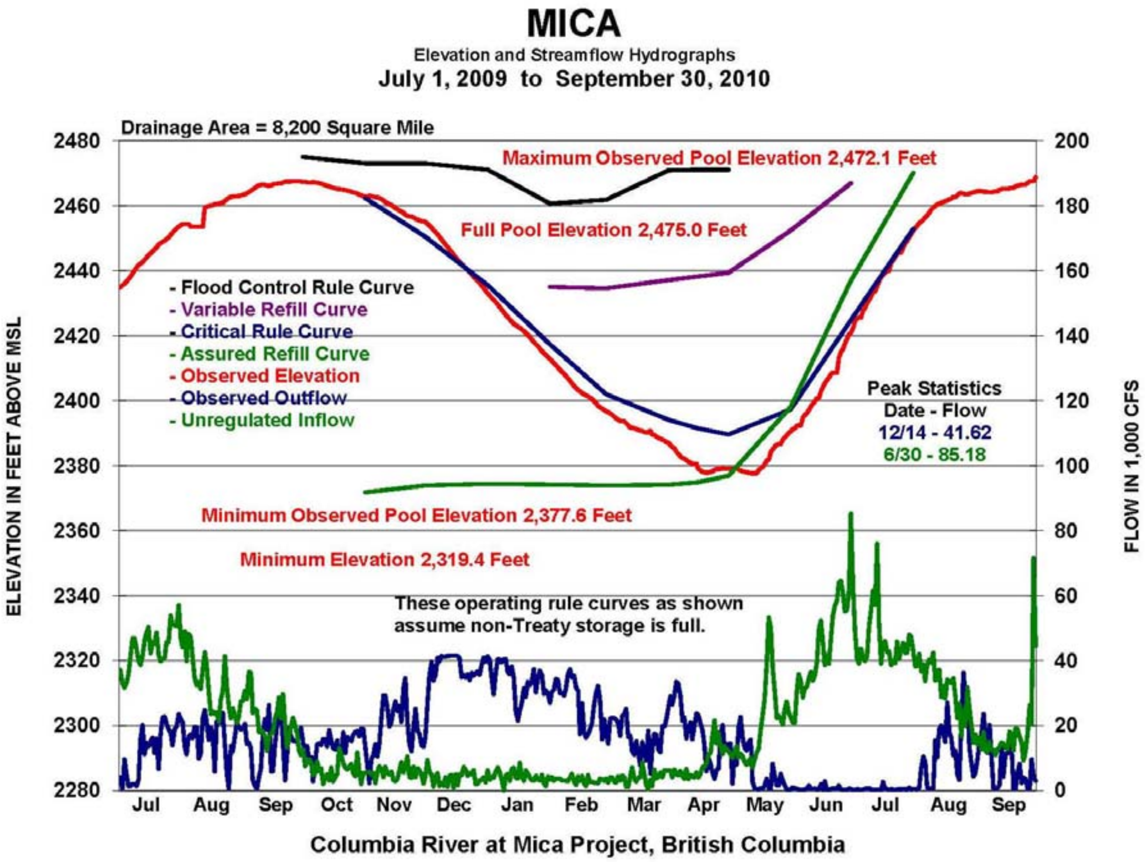


Chart 6: Regulation of Arrow

1 July 2009 – September 2010

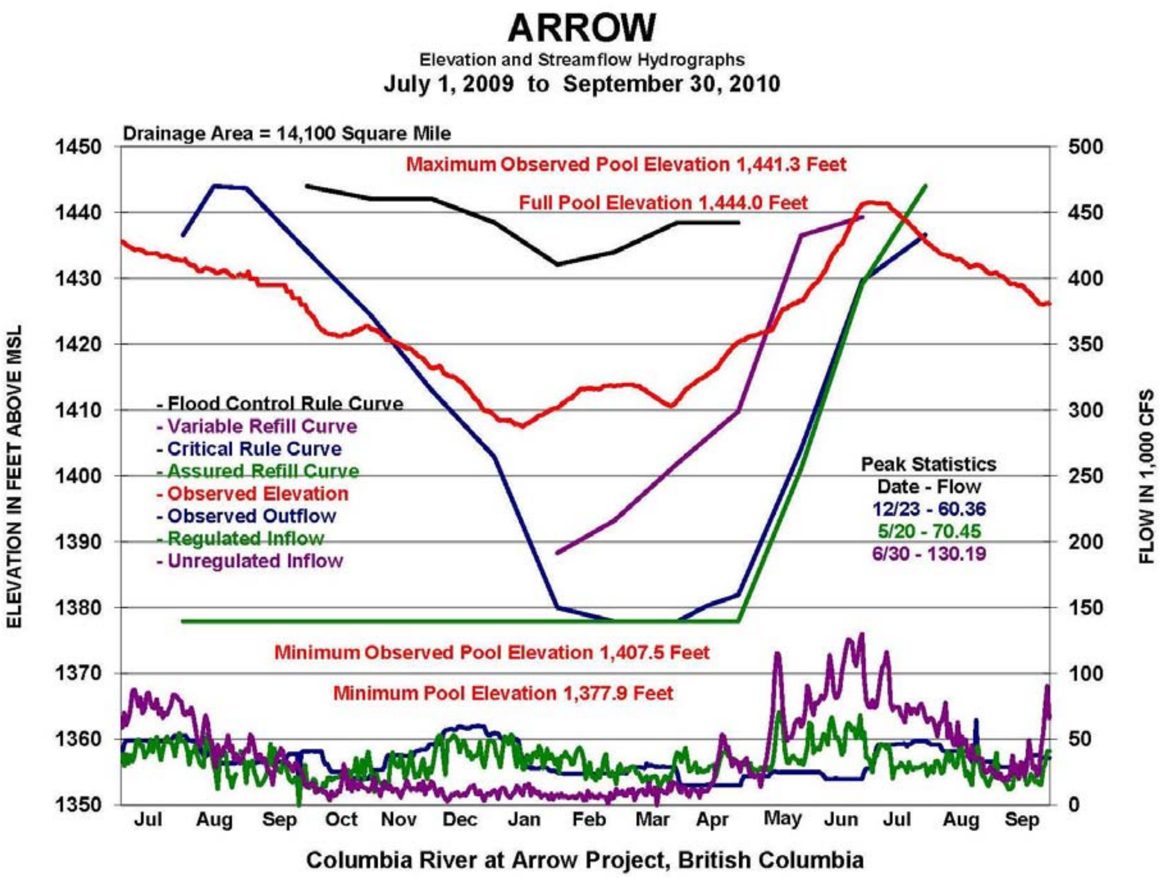


Chart 7: Regulation of Duncan

1 July 2009 – September 2010

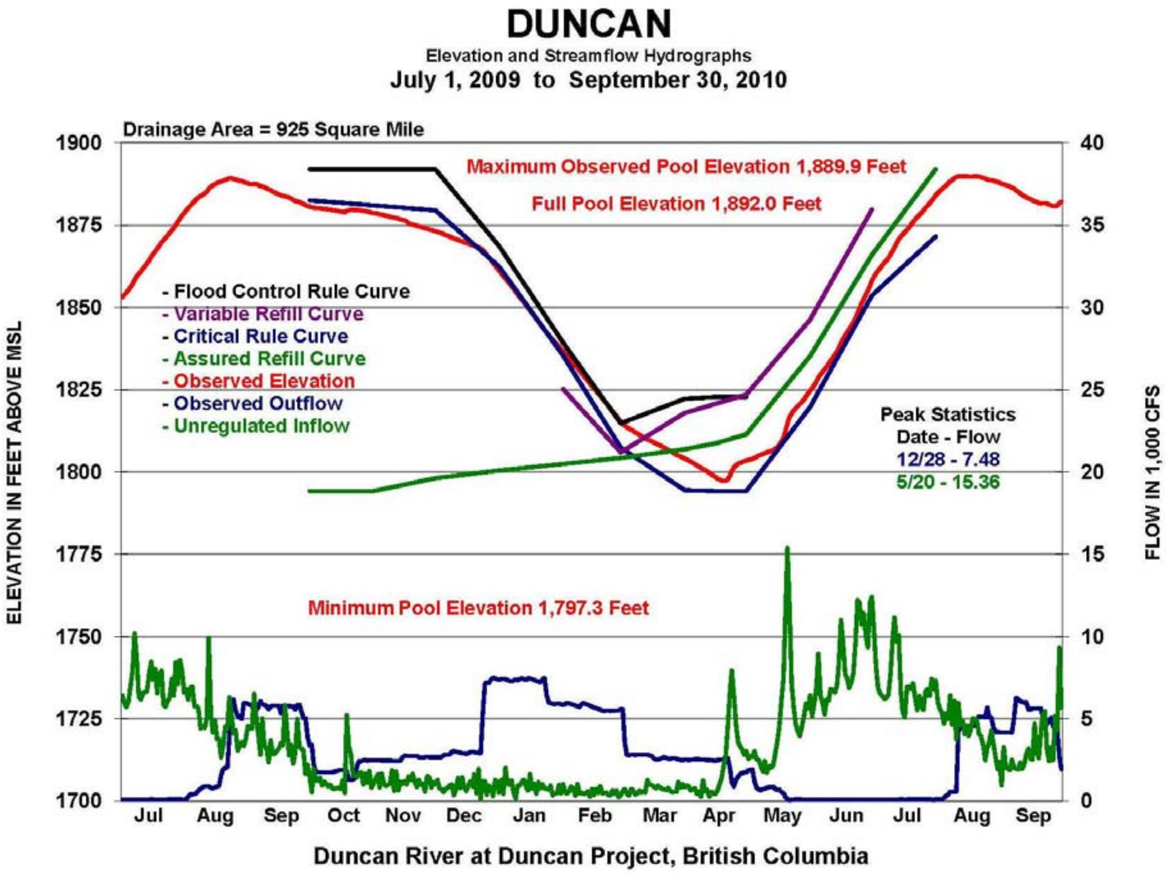


Chart 8: Regulation of Libby

1 July 2009 – September 2010

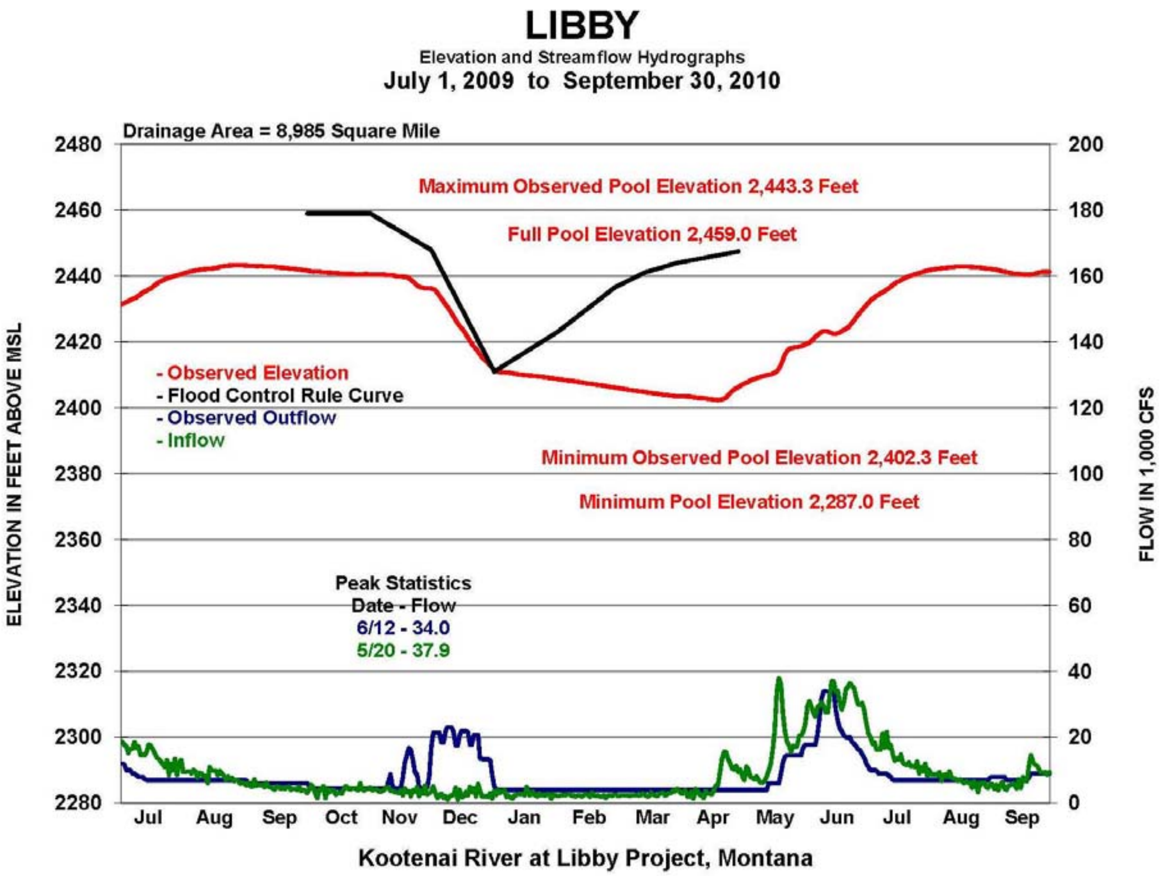


Chart 9: Regulation of Kootenay Lake

1 July 2009 – September 2010

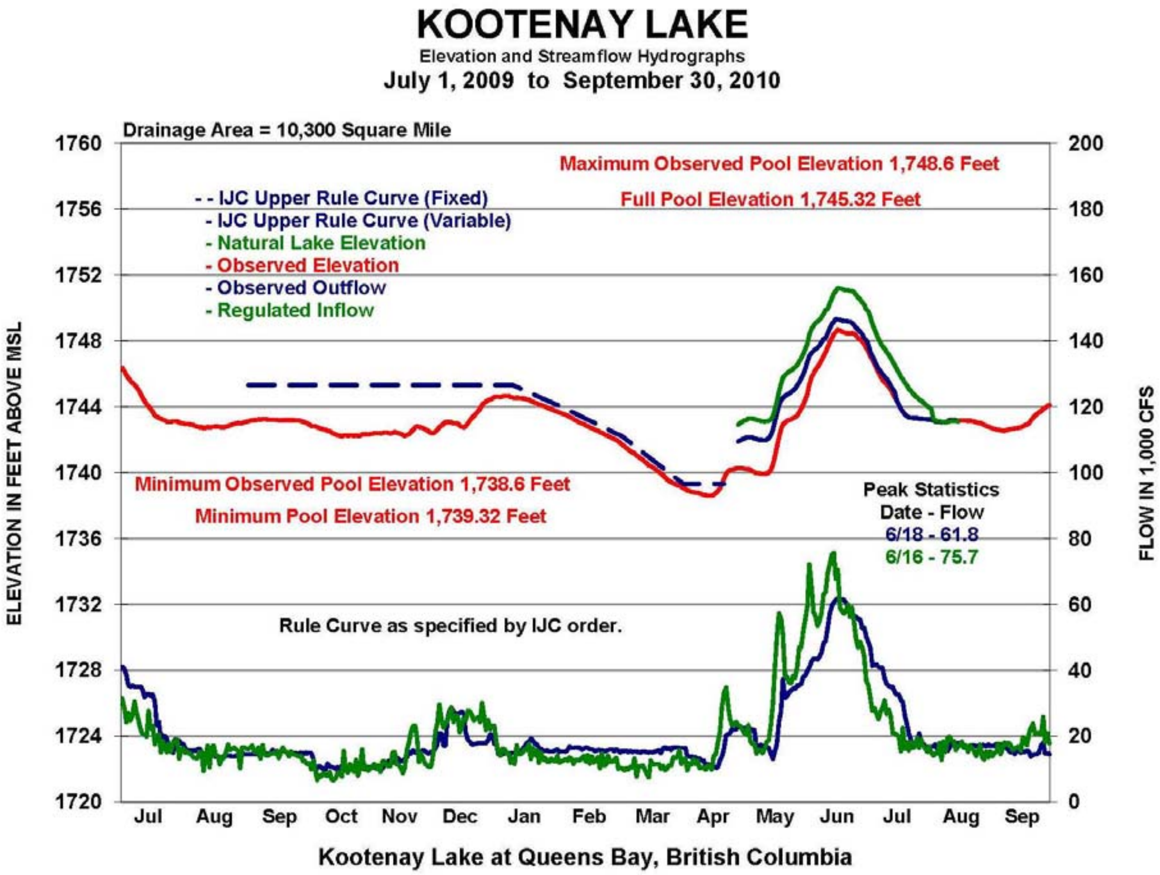


Chart 10: Columbia River at Birchbank

1 August 2009 – 30 September 2010

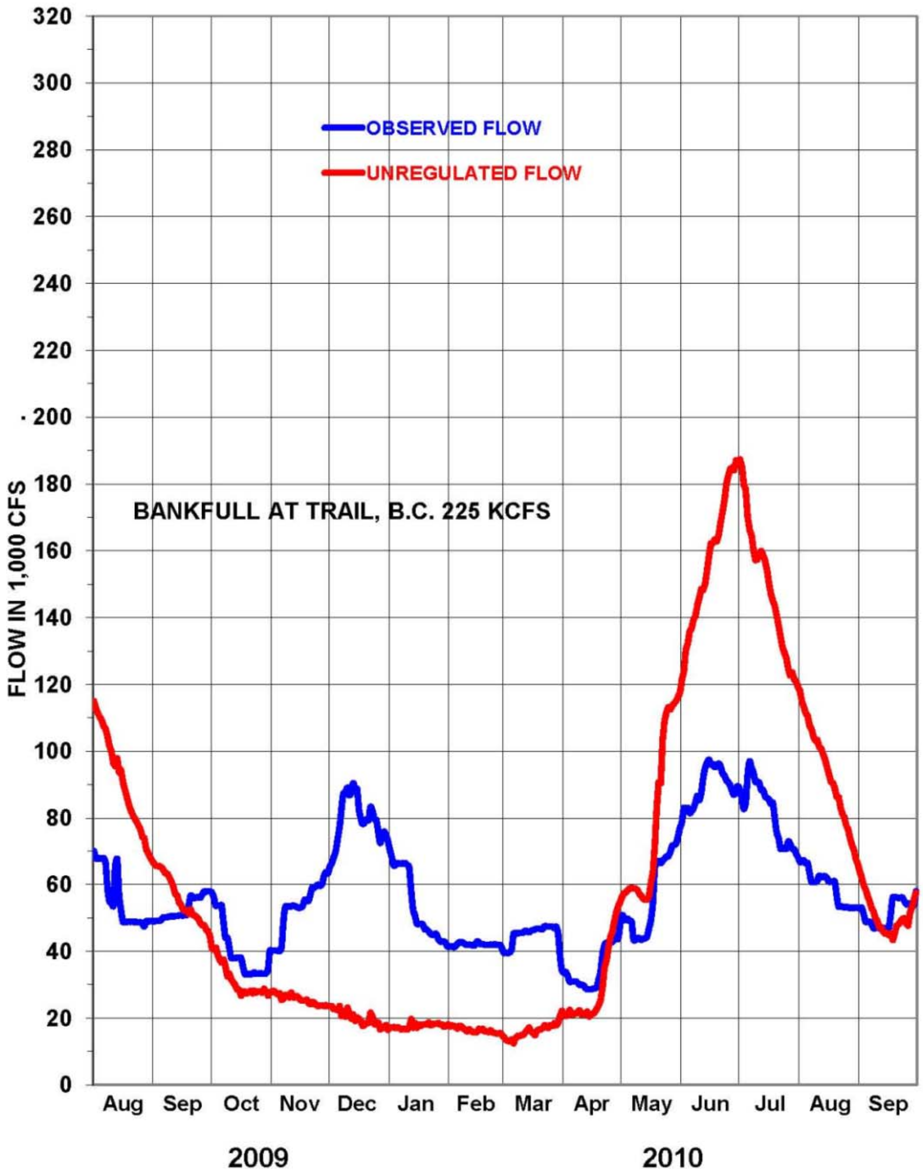


Chart 11: Regulation of Grand Coulee

1 July 2009 – 30 September 2010

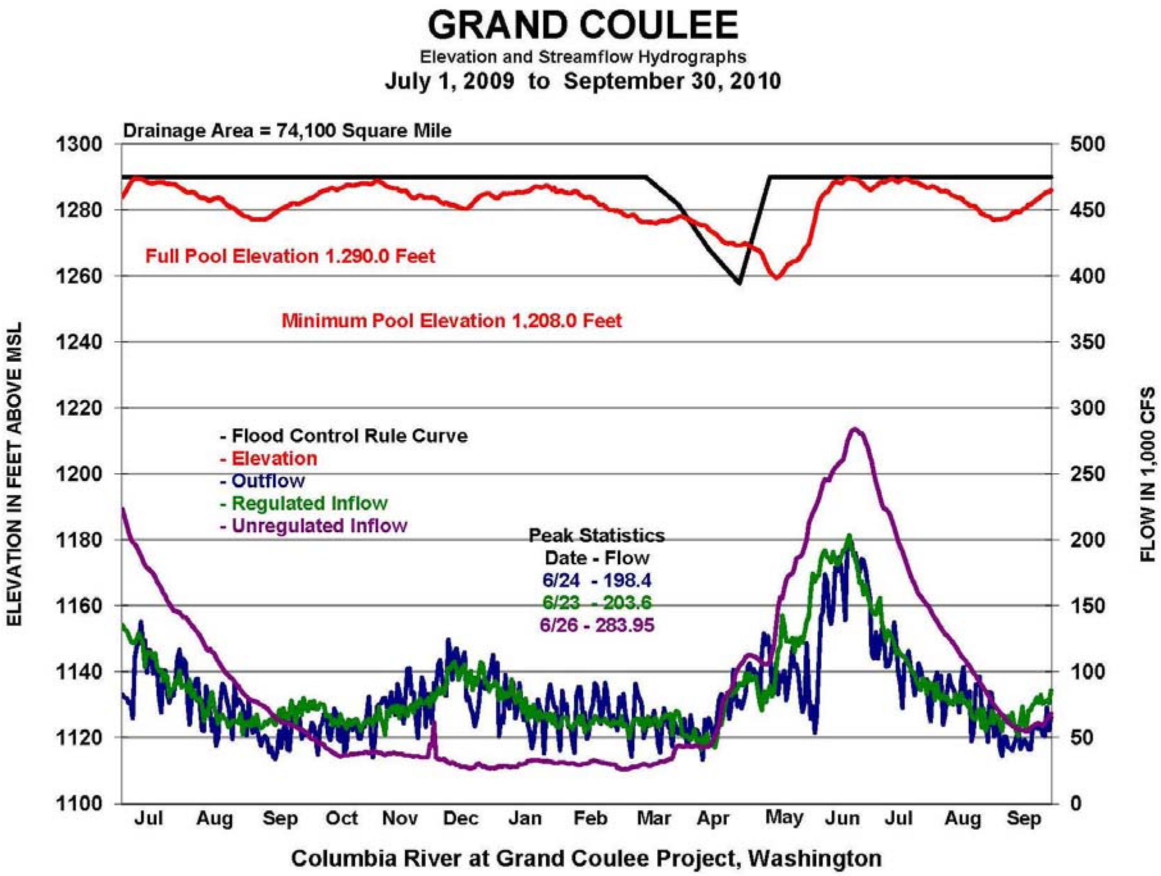


Chart 12: Columbia River at The Dalles

(Summary Hydrograph)

1 August 2009 – 30 September 2010

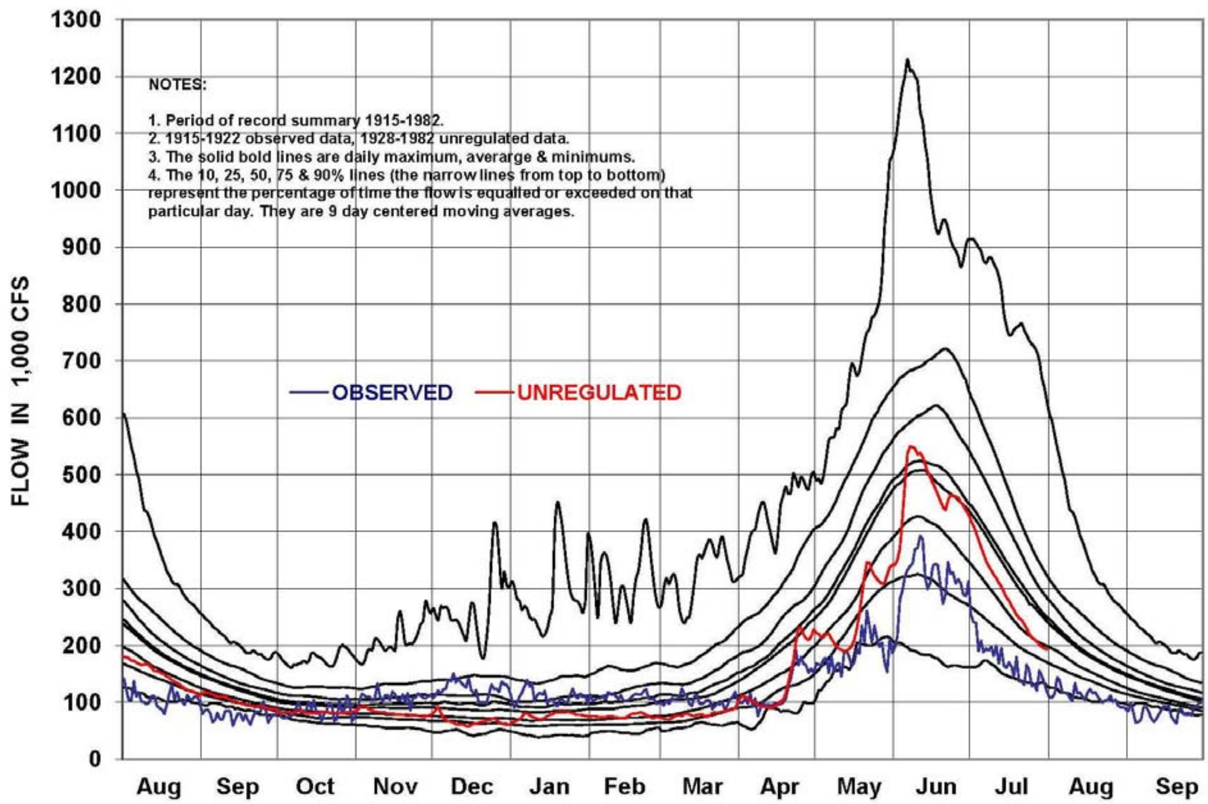


Chart 13: Columbia River at The Dalles

Re-Regulation Plot

1 April 2010 – 31 July 2010

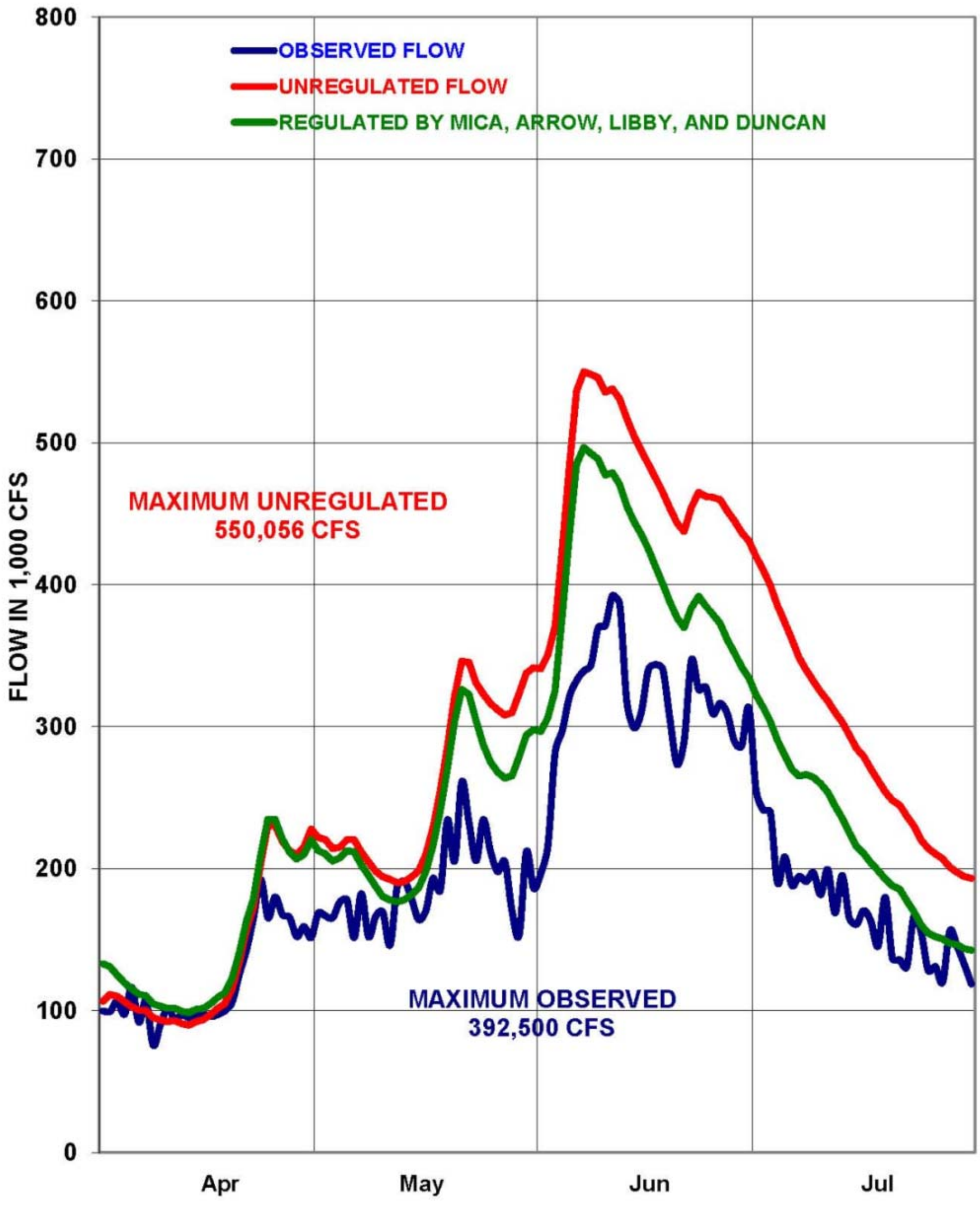


Chart 14: 2010 Relative Filling Arrow and Grand Coulee