ANNUAL REPORT

OF THE

COLUMBIA RIVER TREATY

CANADA AND UNITED STATES ENTITIES

FOR THE PERIOD

1 AUGUST 2010 – 30 SEPTEMBER 2011

For any feedback and comments:

Barbara Miller
Barbara.D.Miller@usace.army.mil

Anthony G. White, BPA
agwhite@bpa.gov

Doug A. Robinson, B.C. Hydro
Douglas.Robinson@bchydro.com

EXECUTIVE SUMMARY

General

Water Year (WY) 2011 was unique in that, after a relatively uneventful winter, near record precipitation and cold temperatures resulted in very high runoff and a very active flood control season. The Canadian Treaty projects, Mica, Duncan and Arrow, were operated during the 1 August 2010 - 30 September 2011 reporting period according to the 2010-2011 and 2011-2012 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 and 12 October 2010 updates 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) 2006 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 2010-11 Storage Agreement (11NTSSA), signed 12 November 2010;
- Columbia River Treaty Entity Agreement on the DOP for Canadian Storage 1 August 2011 through 31 July 2012, signed 21 June 2011;
- Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2015-16, signed 20 September 2011; and

- Columbia River Treaty Entity Agreement on the 2011-12 [Non-Treaty] Storage Agreement (12NTSSA), signed 20 September 2011

Columbia River Treaty Operating Committee Agreements

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

- CRTOC Agreement on Operation of Treaty Storage for Non-power Uses for 11 December 2010 through 31 July 2011 signed on 30 November 2010.

In addition to the Operating Committee agreement listed here, the Bonneville Power Administration (BPA) and British Columbia Hydro and Power Authority (B.C. Hydro) developed two bilateral agreements entitled “2011 Provisional Storage/Draft Agreement (not Treaty) for the Period 16 October 2010 through 31 December 2011,” signed 29 October 2010 and an Agreement for Use of Non-Treaty Storage for the Period 2 September 2011 through 25 November 2011, signed 6 September 2011.

System Operation

Under the 2010-2011 and 2011-2012 DOPs, Canadian storage was operated according to criteria from the 2010-2011 and 2011-2012 AOPs.

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

Canadian storage began the operating year 1 August 2010 on the DOP levels as determined in the TSR study. It remained near the target TSR levels through August except for additional drafts in September and November 2010. Canadian storage was inadvertently drafted below the DOP TSR in September 2010 due to an increase in rainfall late in the month, resulting in record high inflows into Canadian storage. This rain event caused a substantial increase in the TSR-specified storage content after the final TSR was run with actual updated inflows, and after the actual operation had been completed. The inadvertent draft below TSR in November was mainly due to changes in the TSR composite Treaty storage content target throughout the month, as driven by changing inflow forecasts.

During November and December 2010, the Canadian Entity exercised the option to provisionally draft Arrow under the LCA. This 137 cubic hectometer (hm^3 (111 kaf)) provisional draft was returned (stored back) by early February. There was only one LCA cycle implemented this year, as compared to the two cycles provided for, due primarily to unfavorable market conditions.

For January until the end of June 2011, Canadian storage remained above the TSR-specified levels. This was primarily due to the Non-Power Uses operating agreement that was implemented to achieve mutual benefits for the U.S. and Canada. Under provisions of that agreement, the U.S. Entity stored 1233 hm^3 (1 Maf) of flow augmentation water. At the time this was stored, the water supply forecast was slightly less than average. This operation helped to reduce flows downstream of Hugh Keenleyside Dam for Canadian whitefish operation. The flow augmentation water was subsequently released across 15 April through July 2011 to remain below the flood control maximum levels in May through June, meet U.S. salmon flow objectives and manage rapidly increasing stream flow forecasts. The spring water supply forecasts at The Dalles increased as the water year developed, from 109 Maf (January-July) in March to 141 Maf in June.

For July through 15 August 2011, Canadian storage was drafted below TSR levels primarily due to differences in forecast and actual inflows, but also due to the operation of the non-power agreement to smooth Arrow Treaty flows through August.

Canadian Entitlement

For the period 1 August 2010 through 31 July 2011, the Canadian Entitlement amount, before deducting transmission losses, was 535.7 aMW of energy, scheduled at rates up to 1316 MW. From 1 August 2011 through 30 September 2011, the amount, before deducting transmission losses, was 525.9 aMW of energy, scheduled at rates up to 1314 MW. The Canadian Entitlement obligation was determined by the 2010-2011 and 2011-2012 AOP/DDPBs.

During the course of the Operating Year, there were two curtailment periods to Canadian Entitlement deliveries, primarily due to a combination of planned maintenance and unexpected weather/load-resource conditions. These included a total of 1793 MWh over two days in September 2010 and 6 MWh in one hour in November 2010. All of the curtailed power was delivered later within the month of curtailment as agreed.

Treaty Project Operation

At the beginning of the 2010-2011 operating year, 1 August 2010, actual Canadian storage was at 15.9 km^3 (12.9 Maf) or 82.9 percent full. Canadian storage ended the Operating Year on 31 July 2011, at 18.9km^3 (15.3 Maf) or 99.2 percent full.

The Mica (Kinbasket) Reservoir reached a maximum elevation of 753.50 m (2472.1 ft), 0.88 m (2.9 ft) below full pool on 13 October 2010 due to a rainfall event in late September resulting in a record high inflow. The reservoir was drawn down during the fall and winter to meet electrical demands and to prepare for above normal spring runoff. It reached a minimum this year of 725.0 m (2378.6 ft) on 6 May 2011, comparable to the 2010 minimum level. From early May through early July, Mica generation was reduced to near minimum required for fish flush and as is normal in response to lower electrical demands in the summer and must-run generation elsewhere in the system. Due to above normal snowpack in the Columbia basin, generation was increased across July/August to meet market opportunities as well as for reservoir control to minimize spill risks. Due to high freshet inflows, B.C. Hydro sought and received permission from the Comptroller of Water Rights in August to surcharge the reservoir by 0.3 m (1 ft) up to 2476 ft on an interim basis for power and flood control purposes. The option to surcharge the reservoir will help minimize spill probabilities and amounts. In response to a rain event in late September/early October, the reservoir continued to fill to reach a peak level of 754.17 m (2474.3 ft) on 3 October 2011. The last time the reservoir filled to near full was in 2007.

The Arrow Lakes Reservoir reached a maximum elevation of 439.3 m (1441.3 ft), or 0.82 m (2.7 ft) below full pool on 5 July 2010. Canadian projects operated in proportional draft mode from late summer to early December to meet Treaty firm loads while balancing the need to refill Mica, Arrow Lakes and Duncan Reservoirs by July/August. Even in proportional draft, Arrow Lakes Reservoir remained relatively high primarily due to Treaty flex operations (Mica releases) and the complete refilling of the storage space managed under the July 1990 Non-Treaty Storage Agreement (NTSA). Arrow Lakes Reservoir reached a minimum level of 430.59 m (1412.7 feet) on 10 April 2011. By comparison, the Arrow Lakes Reservoir reached a minimum level of 429.00 m (1407.5 ft) on 14 January 2010. As basin inflows increased from snowmelt runoff during May through early July, the reservoir filled quite rapidly up to its Treaty flood control level (upper rule curve) to reach a maximum level of 439.6 m (1442.1 ft), or 0.58 m (1.9 ft) below full pool on 28 July 2011. The last time the reservoir filled to within 1 ft of full was on 6 July 2008. Arrow Reservoir then drafted across the summer months reaching 438.09 m, 436.84 m (1437.3 ft, 1433.2 ft) by 31 August and 30 September 2011, respectively.

Duncan Reservoir refilled to 576.04 m (1889.9 ft) or 0.64 m (2.1 ft) below full on 12 August 2010. From September 2010 through April 2011, Duncan was operated to supplement inflow into Kootenay Lake to provide spawning and incubation flows for fish and to meet Treaty flood control requirements. As in most years, the reservoir was drafted to near empty in late April or early May. Duncan Reservoir reached its licensed minimum level for the year of 546.9 m (1794.2 ft) on 1 May 2011. By comparison, in 2010, the reservoir reached a minimum elevation of 547.1 m (1797.31 ft) on 18 April 2010. Reservoir discharge was reduced to a minimum of 3.0 m^3/s (0.1 kcfs) in early June to initiate reservoir refill. In response to a significant local rainstorm in late July/early August, B.C. Hydro applied and received permission from the Comptroller of Water Rights to store 0.30 m (1 ft) above the maximum elevation in August up to 576.99 m (1893 ft). Duncan Reservoir reached a maximum level of 576.71 m (1892.2 ft) or 0.03 m (0.1 ft) above full on 1 August 2011 and Duncan discharges peaked at 16.8 kcfs (475 m^3/s) measured at Duncan River below the Lardeau confluence (DRL) gauging station on 5 August 2011. As inflows subsided, Duncan discharges were adjusted as needed across August through to 5 September (Labor Day) to target a reservoir elevation of ~574.9 +/- 0.3 m (~1886 +/- 1 ft) for the Spillway Operating Gate (SPOG) rehabilitation work starting mid October. For the balance of September, project flows were increased to facilitate drafting of the reservoir to reach an elevation of 572.14 m (1877.1 ft) on 30 September 2011.

The Libby (Koocanusa) Reservoir filled to a maximum elevation of 744.6 m (2442.9 ft) on 17 August 2010, 4.9 m (16.1ft) from full pool. The reservoir drafted through the fall and winter period. By 31 December 2010, the reservoir was at elevation 735.2 m (2412.0 ft) and operated during the winter to the VARQ storage reservation diagram. The winter period was characterized by above average snow build-up and a continuously rising water supply forecast (WSF). Lake Koocanusa was drafted to an end of April elevation of 716.3 m (2349.9 ft.), 2.8 m (9.3 ft.) below the flood control target. The reservoir drafted to its lowest elevation of 712.5 m (2337.7 ft) on 12 May 2011. Outflow was adjusted pursuant to VARQ rules well above the minimum VARQ flow of 343 m^3/s (12.1 kcfs), due to the high seasonal runoff volume forecast. Libby Dam provided 1.48 km^3 (1.2 Maf) of storage for sturgeon releases and released the storage accumulated by 11 July 2011. The reservoir filled to a maximum elevation of 747.8 m (2453.4 ft) on 04 August 2011, 1.7 m (5.6 ft) from full pool and drafted to elevation 746.1 m (2447.7 ft) by 31 August 2011, and to elevation 745.8 m (2446.8 ft) by 30 September 2011.

Columbia Basin Map

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Acronyms and Abbreviations

AER..Actual Energy Regulation
aMW………………………... ....Average Megawatts
AOP……………………….............Assured Operating Plan
B.C. Hydro...British Columbia Hydro and Power Authority
BiOp..Biological Opinion
BG …...Brigadier General
BPA...Bonneville Power Administration
CEEA ....Canadian Entitlement Exchange Agreement
CEPA ....Canadian Entitlement Purchase Agreement
cfs..Cubic feet per second
COL ………………………………..Colonel
CRC...Critical Rule Curve
CRT...Columbia River Treaty
CRITFC...Columbia River Inter-Tribal Fish Commission
CRTHC ....Columbia River Treaty Hydrometeorological Committee
CRTOC ....Columbia River Treaty Operating Committee
CSPE...Columbia Storage Power Exchange
DDPB..Determination of Downstream Power Benefits
DOP...Detailed Operating Plan
DRL...Duncan River below the Lardeau confluence
ESP..Ensemble Streamflow Prediction
FCOP...Flood Control Operating Plans
ft ....feet
hm^3 ....Cubic hectometers
in ....inch
ICF ....Initial Controlled Flow
IJC...International Joint Commission
kaf ....Thousand acre feet
kcfs..Thousand cubic feet per second
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

NTSSA...Non-Treaty Special 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 for Preparation and Use of Assured and Detailed Operating Plans for Columbia River Treaty Storage

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 2011 water year (WY) 1 October 2010 through 30 September 2011, with additional information on the operation of Mica, Arrow, Duncan, and Libby Reservoirs as needed to also cover off the reservoir system operating year, 1 August 2010 through 31 July 2011. The power and flood control effects downstream in Canada and the U.S. are described. This report is the 45th of a series of annual reports covering the period since the ratification of the Columbia River Treaty (Treaty, CRT) in September 1964.

Duncan, Arrow, and Mica Reservoirs in Canada were constructed as required under the CRT, and Libby Reservoir in the U.S. was constructed as provided for by the CRT. Treaty storage in Canada (Canadian storage) is operated for the purposes of flood control and increasing hydroelectric power generation in Canada and the U.S. In 1964, the Canadian and the U.S. governments each designated at least one Entity to formulate and carry out the operating arrangements necessary to implement the CRT.

The Canadian Entity for these purposes is B.C. Hydro. The Canadian Entity for the limited purpose of making arrangements for disposal of all or portions of the Canadian Entitlement within the United States is the government of the Province of British Columbia. The U.S. Entity is the Administrator/Chief Executive Officer of Bonneville Power Administration (BPA) and the Division Engineer of the Northwestern Division, U.S. Army Corps of Engineers (USACE).

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

1. Canada was to provide 19.12 cubic kilometers (km^3) (15.5 million acre feet (Maf)) of usable storage. This has been accomplished with 8.63 km^3 (7.0 Maf) in Mica, 8.78 km^3 (7.1 Maf) in Arrow, and 1.73 km^3 (1.4 Maf) in Duncan.

2. For the purpose of computing downstream power benefits, the U.S. base system hydroelectric facilities will be operated in a manner that makes the most effective use of the improved 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 $64.4 million (U.S.) for one half of the present worth of expected future flood control benefits in the U.S. to September 2024, resulting from operation of the Canadian storage.

5. Under certain specified conditions, the U.S. has the option of requesting the evacuation of additional flood control space above that specified in the CRT, for a payment of $1.875 million (U.S.) plus power losses for each of the first four requests for this "on-call" storage. No requests under this provision have been made to date.

6. The U.S. had the option (which it exercised) to construct Libby Dam with a reservoir that extends 67.6 kilometers (42 miles) into Canada and for which Canada agreed to make the land available.

7. Both Canada and the U.S. have the right to make diversions of water for consumptive uses. In addition, since September 1984, Canada has had the option of making, for power purposes, specific diversions of the Kootenay River into the headwaters of the Columbia River.

8. Differences arising under the Treaty 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, as well as a joint Permanent Engineering Board (PEB) to review and report on operations under the CRT.

II - TREATY ORGANIZATION

Entities

There was one meeting of the CRT Entities (including the Canadian and U.S. Entities and Entity Coordinators) during the year on the morning of 9 February 2011 in Vancouver, B.C.

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

UNITED STATES ENTITY

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

Brigadier General John R. McMahon, Member
Division Engineer
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY

Mr. David G. Cobb, Chair
President & Chief Executive Officer
British Columbia
Hydro and Power Authority
Vancouver, British Columbia

The Entities have designated alternates to act on behalf of the primaries in their absence; appointed in the U.S. by a Memorandum of Agreement between Bonneville Power Administration and Corps of Engineers, and in Canada by the B.C. Hydro Board of Directors. Mr. Wright's alternate is Bonneville Power Administration Deputy Administrator, a position currently vacant; Mr. Cobb's alternate is Chris K. O'Riley, Executive 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, or appoint additional Entities for specific purposes.

Entity Coordinators & Secretaries

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

UNITED STATES ENTITY COORDINATORS

Stephen R. Oliver
Vice President, Generation Supply
Bonneville Power Administration
Portland, Oregon

G. Witt Anderson
Director, Civil Works & Management
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY COORDINATOR

Renata Kurschner
Director,
Generation Resource Management
B.C. Hydro
Burnaby, British Columbia

UNITED STATES ENTITY SECRETARY	**CANADIAN ENTITY SECRETARY**
Dr. Anthony G. White Regional Coordination Power and Operations Planning Bonneville Power Administration Portland, Oregon	Douglas A. Robinson Generation Resource Management B.C. Hydro 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:

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

* Mr. William Proctor was appointed to replace Mr. Steven Barton on 1 August 2011.

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 then-current hydroelectric operating plans and FCOP;
- ♦ Coordinated changes to procedures and reviewed scheduled delivery of the Canadian Entitlement according to the CRT and related agreements;
- ♦ Completed the 2015-2016 AOP/DDPB;
- ♦ Completed the 1 August 2011 through 31 July 2012 DOP;

- Completed one supplemental operating agreement for Canadian storage;

- Implemented the Libby Coordination Agreement (LCA) including the 12 October 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; and

- Briefed the PEBCOM on Entity activities, and completed the 2010 Entity Annual Report.

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.

CRT Operating Committee at Rock Island Dam, July 2011. Pictured from left to right are Alaa Abdalla and John Hyde, members; Jim Barton and Rick Pendergrass, U.S. Alternate Chairs; Kelvin Ketchum, Canadian Chair; Gillian Kong, member; and Tony White, Secretary to the U.S. Entity.

Columbia River Treaty Hydrometeorological Committee

The Columbia River Treaty Hydrometeorological Committee (CRTHC) was established in September 1968 by the Entities and is responsible for coordinating hydrometeorological data collection, data exchange and water supply forecasting for the Columbia River Treaty projects in accordance with the Treaty and otherwise assisting the Entities as needed. The Committee consists of 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
	Adam Gobena, B.C. Hydro, Member *

* Mr. Adam Gobena was appointed to replace Mr. Frank Weber as of 26 September 2011.

The CRTHC met three times in the 2011 operating year:

Meeting 66: 30 November 2010

Meeting 67: 15 March 2011

Meeting 68: 30 August 2011

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

The 2010 CRTHC Annual Report was completed in January 2011, in advance of the annual Permanent Engineering Board Meeting.

Forecasting

New water supply forecast equations for Libby were accepted by the CRTHC and the CRTOC for use beginning in December of the 2010/2011 operating year. Forecast errors and hedges were updated in Appendix 8 of POP.

In August, the Northwest River Forecast Center (NWRFC) announced they were changing their official forecast procedures in the 2012 water year to use ensemble streamflow prediction (ESP), replacing previous statistical and single-trace procedures. NWRFC will be updating water supply forecasts much more frequently than in the past. The CRTHC invited Don Laurine from the NWRFC to the 30 August committee meeting to discuss the change. The CRTHC is working with the NWRFC to determine which forecast updates will be used as input for Treaty operations planning.

Data Exchange

During the changeover from Daylight Savings time to Standard time on 7 November 2010, the extra hour of generation at Mica over the time change caused an error in the h/k calculation for Treaty accounting. A temporary fix was implemented at the time, and as of September 2011, a permanent fix to the reporting system at B.C. Hydro had not yet been implemented.

B.C. Hydro converted to a new hydromet data management system called WISKI in July 2011. The USACE continues with testing of the new Regional Water Control Data System.

Stations

The CRTHC wrote a station network status report documenting changes to network from 2005-2010 which was presented to the PEB in February. CRTHC is working on an updated listing of all Treaty stations, and will be re-instating letters to agencies which manage Treaty monitoring stations to remind them of the importance of the continued operation of these stations.

BPA performed an analysis to determine best locations in the Canadian Columbia to convert existing snow courses to automated snow pillow sites to enhance the real-time monitoring of snow accumulations in the region. The resulting report proposed to add five additional automated stations mainly in the Mica/Revelstoke area. The final report was presented to the CRTOC in May. BPA and B.C. Hydro are working out a Memorandum of Understanding regarding the installation and maintenance of the sites. Field assessments of the proposed locations are being undertaken in September 2011, and the earliest potential installation is expected in summer 2012.

Permanent Engineering Board

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

UNITED STATES SECTION	**CANADIAN SECTION**
Stephen L. Stockton, Chair Washington, D.C.	Jonathan Will*, Chair Ottawa, Ontario
Edward Sienkiewicz, Member Newberg, Oregon	Tim Newton, Member Vancouver, British Columbia
Dr. Robert A. Pietrowsky, Alternate Washington, D.C.	Glen Davidson, Alternate Victoria, British Columbia
George E. Bell, Alternate Portland, Oregon	Ivan Harvie, Alternate Calgary, Alberta

* Jonathan Will is acting as the Canadian Chair of the PEB, but has not been formally installed in this position as of 1 October 2011.

The following serve as Secretaries to the Board:

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

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

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

- Consult with the Entities in the establishment and operation of a hydrometeorological system; and

- Investigate and report on any other CRT related matters at the request of either government.

The Entities continued their cooperation with the PEB during the past year by providing copies of Entity agreements, operating plans, CRTOC agreements, updates to hydrometeorological documents, personnel appointments, pertinent correspondence, and the annual Entity report to the PEB for their review. The annual joint meeting of the PEB and the Entities was held on 9 February 2011 in Vancouver, B.C., where the Entities briefed the PEB on the preparation and implementation of operating plans, the delivery of the Canadian Entitlement, the 2014 CRT Review, and other topics requested by the PEB.

PEB Engineering Committee

The PEB has established the PEBCOM to assist in carrying out its duties. The members of PEBCOM at the end of 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 Operating Committee on 20 October 2010 in Portland, Oregon.

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.

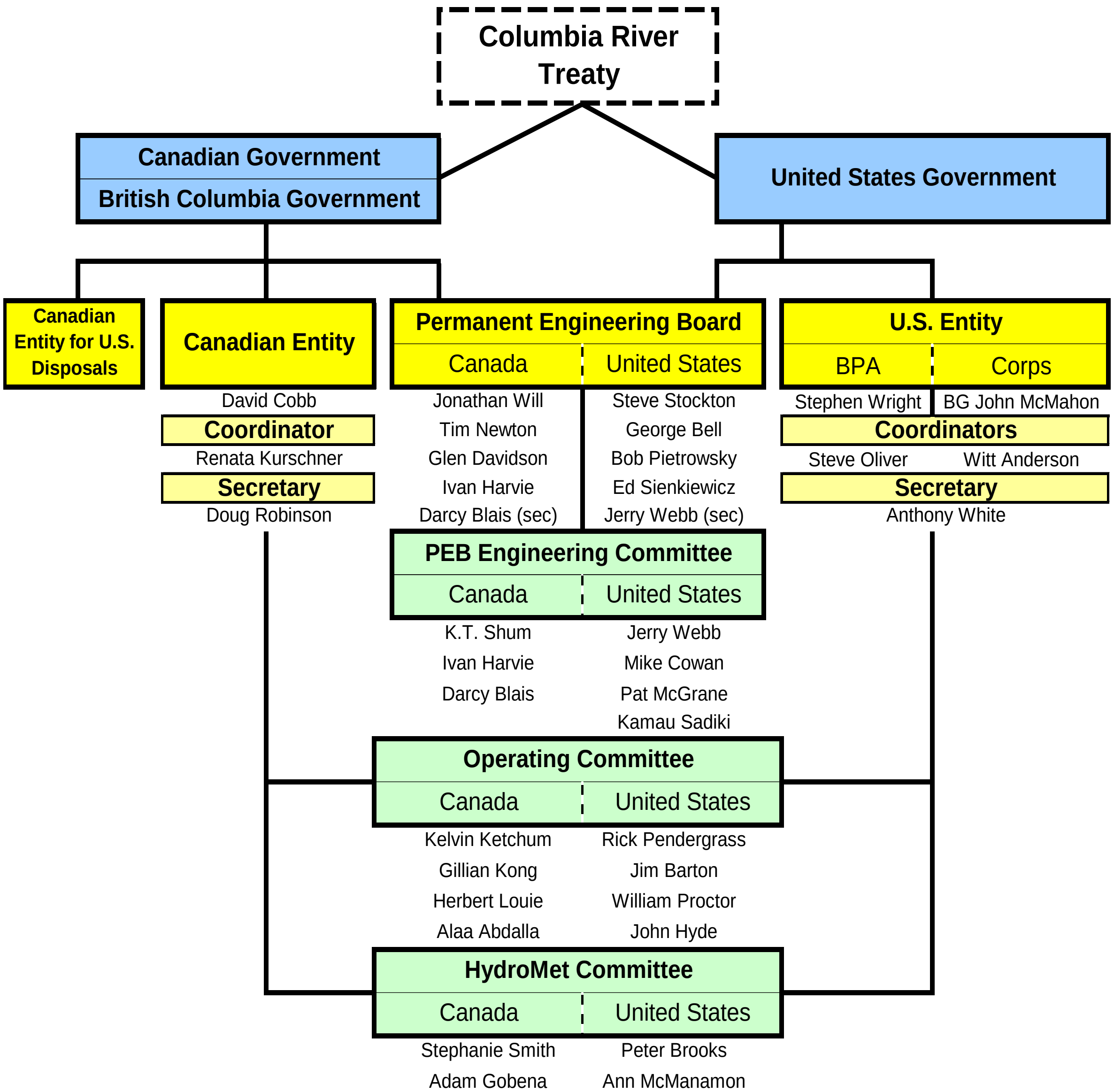
The U.S. Section Chair is Ms. Lana Pollack of Ann Arbor, Michigan. The Canadian Section Chair is Joseph Comuzzi of Thunder Bay, Canada. Canadian members are Mr. Lyall D. Knott, Vancouver, B.C., and Mr. Pierre Trepanier, Montreal, Quebec. U.S. members are Mr. Rich Moy of Helena, MT and Ms. Dereth Glance of Syracuse, NY.

Presentations

During the period covered by this report, CRT personnel made presentations about the history, structure, operations, challenges and communications associated with the CRT to visitors and inquirers from professional, environmental, academic and civic groups and individuals; new employees; Northwest Power and Conservation Council staff; law seminar attendees in Vancouver, B.C.; a visitation to the Mekong River area, and presentations to the U.S. Society on Dams annual conference; the BPA-NOAA Wind Integration Workshop in Portland; 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.

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 to both countries than the AOP. The Protocol to the CRT provides further detail and clarification of the principles and requirements of the CRT.

The "Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans for Canadian Treaty Storage," signed December 2003 (as amended), together with the "Columbia River Treaty Flood Control Operating Plan" dated May 2003 (as revised), establish and explain the general criteria used to develop the AOP and DOP and operate CRT storage during the period covered by this report.

The planning and operation of CRT Storage as discussed on the following pages are for the operating year, 1 August 2010 through 31 July 2011. The operation of Canadian storage was determined by the 2010-2011 DOP and supplemental operating agreements. The DOP required a semi-monthly Treaty Storage Regulation (TSR) study to determine end-of-month storage obligations (prior to any adjustments associated with supplemental operating agreements). The TSR included all operating criteria from, and was based on, the Step I Joint Optimum Power Hydroregulation Study from the 2010-2011 AOP, with agreed changes. Most of the hydrographs and reservoir charts in this report are for a 14-month period, August 2010 through September 2011.

Assured Operating Plans

During the reporting period, the Entities completed studies needed to develop the 2015-2016 Assured Operating Plans (AOP). An Entity agreement approving the 2015-2016 AOP was signed on 20 September 2011. The 2015-2016 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 2015-2016 AOP establishes Operating Rule Curves (ORCs), Critical Rule Curves (CRCs), Mica and Arrow Project Operating Criteria, and other operating criteria included in the Step I Joint Optimum Power Hydroregulation Study, to guide the operation of Canadian storage. The ORCs were derived from CRCs, Assured Refill Curves (ARCs), Upper Rule Curves (Flood Control Rule Curves), Variable Refill Curves (VRC), Operating Rule Curve Lower Limits (ORCLL), and Variable Refill Curves Lower Limits (VRCLL), consistent with flood control requirements, as described in the 2003 POP. They provide guidelines for draft and refill under a wide range of possible water conditions. The Flood Control Rule Curves conform to the 2003 FCOP and are used to define maximum reservoir levels for the operation of Canadian storage. The 2015-2016 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 Determination of Downstream Power Benefits (DDPB) resulting from Canadian storage operation is made in conjunction with the AOP according to procedures defined in the CRT, Annexes, and Protocol and, except as noted in the AOP/DDPB documents, the POP agreement. The 2015-2016 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 2015-2016 operating year were determined to be 2664.6 MW of dependable capacity, and

977.4 average annual MW of usable energy. Therefore, the Canadian Entitlement to downstream power benefits was 1332.3 MW of capacity, which was a 36.3 MW decrease from the 2014-2015 DDPB, and 488.7 MW of average annual energy, which was an 8.8 MW increase from the 2014-2015 DDPB. The changes to Canadian Entitlement compared to the prior DDPB are mainly due to changes in the firm loads, the amount of and maintenance schedules for thermal installations and an increase in renewable resources (mostly wind).

Canadian Entitlement

For the period 1 August 2010 through 31 July 2011, the Canadian Entitlement amount, before deducting transmission losses, was 535.7 aMW of energy, scheduled at rates up to 1316 MW. From 1 August 2011 through 30 September 2011, the amount, before deducting transmission losses, was 525.9 aMW of energy, scheduled at rates up to 1314 MW. The Canadian Entitlement obligation was determined by the 2010-2011 and 2011-2012 AOP/DDPBs.

During the course of the Operating Year, a number of 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 1793 MWh in September 2010 and 6 MWh in November 2010 was returned later within each month of curtailment as agreed.

Detailed Operating Plans

During the period covered by this report, the CRTOC used the "Detailed Operating Plan for Columbia River Treaty Storage” (DOP) for 1 August 2010 through 31 July 2011, dated June 2010 and the DOP for 1 August 2011 through 31 July 2012, dated June 2011, 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 2010-2011 and 2011-2012 DOPs were based respectively on the 2010-2011 AOP and 2011-2012 AOP loads and resources, rule curves, and other operating criteria with agreed changes for both Canadian and U.S. projects. The 2010-11 and 2011-2012 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 2010-2011 DOP and 2011-2012 DOP operating criteria were used to develop the Treaty Storage Regulation (TSR) studies for implementation of Canadian storage operations. The changes from the AOP were mainly updates to hydro-independent data, incorporation of updated forecast errors and distribution factors, 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 2011 were determined on the basis of seasonal volume runoff forecasts during actual operation. The VRC calculations for Canadian reservoirs and Libby for the 2010-2011 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 12 October 2010.

Entity Agreements

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

Date Signed by Entities	Description of Agreement
12 November 2010	Columbia River Treaty Entity Agreement on the 2010-2011 Storage Agreement (11NTSSA)
21 June 2011	Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Canadian Storage 1 August 2011 through 31 July 2012
20 September 2011	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 2015-2016.
20 September 2011	Columbia River Treaty Entity Agreement on the 2011-2012 [Non-Treaty] Storage Agreement (12NTSSA)

Columbia River Treaty Operating Committee Agreements

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

Date Signed	Description	Authority
30 November 2010	CRTOC Agreement on Operation of Treaty Storage for Non-power Uses for 11 December 2010 through 31 July 2011	Detailed Operating Plan 1 August 2010 through 31 July 2011, 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 ensure 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. No further extension of the contract was completed, however; and, as per contract terms, release rights under the NTSA terminated effective 30 June 2004. Both B.C. Hydro and U.S. accounts were filled to 100 percent of full on 7 January 2011, full for each account being 2.25 million acre-feet (Maf) (1134.4 thousand second-foot-days (ksfd)).

In absence of a new long term Non Treaty agreement, flexibility for shaping flows was provided through the following two agreements:

- 2011 Provisional Storage/Draft Agreement (Not Treaty) for the Period 16 October 2010 through 31 December 2011. This short term agreement included three components: fall storage and release, Provisional draft and return and spring/summer flow shaping, and;
- Agreement for Use of Non-Treaty Storage for the Period 2 September 2011 through 25 November 2011, signed 6 September 2011. This short term agreement was intended to provide flexibility prior to implementation of a new long-term Non-Treaty Storage Agreement.

IV - WEATHER AND STREAM FLOW

Weather for 2010-2011

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: Cooler than normal.

Sparse heating 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 of 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 break down 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 U.S. 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.

A persistent jet stream over the Northwest U.S. and Southwest Canada brought a series of lower pressure system to the area. This helped push the monthly precipitation to above normal for much of the region during October and caused some of the flooding in Western Washington. The low pressure trough continued to reside over the western U.S. and Canada for much of the month of November. This helped bring cold air down from the arctic into the region and kept temperature cooler than normal. Precipitation was near normal for the period for most of the region with the exception of southern British Columbia where precipitation was slightly below average.

Unsettled upper level flow kept weather showery and temperature near normal for the first week of December. By the second week, southwesterly upper level flow had set up over the region bringing above normal temperatures and precipitation. With moist conditions in place, a cold front that came during the middle of the second week helped produce heavy rain and snow through much of the region west of the Cascade Mountains. Runoff associated with this event brought high water to much of the area and broke many daily precipitation records. Later in the month, a low pressure system kept weather unsettled and temperature below normal.

January started off cold with northerly upper level flow pushing cold continental air through much of the southern British Columbia. The cold air and clear conditions helped strengthen inversion and brought very cold temperatures to many valley areas. By the second week of the month, high pressure began to build over the southern half of the basin bringing warmer than normal and drier than normal conditions to the region.

February started out warm on the west side of the Cascades and cooler on the east. These conditions changed quickly when a progressive upper level flow brought cold temperatures and some heavy precipitation to the region. Conditions remained stormy throughout the remainder of the month. Stormy conditions continued through the month of March, with above average precipitation and near normal temperatures.

The jet stream brought cold low pressure system over the Northwest U.S. and southern British Columbia all through April. Temperatures were well below normal and many daily and seasonal records were broken. Systems were often wet as well, which brought above average rain and snow to the region. These same conditions continued through the month of May, with above average precipitation and snow.

In June, the jet stream moved north up into British Columbia but still helped bring cool wet storms to southern British Columbia and the Northwest U.S. Fairly widespread accumulating snow continued through the region through the third week of the month. Generally warmer conditions prevailed the last week of the month helping to melt snow and bring higher flows to many rivers.

An upper level low pressure trough resided over the eastern Pacific Ocean and into British Columbia, Washington and Oregon through most of July. This kept cool conditions through the region and brought higher than normal precipitation to British Columbia. Gulf moisture wrapped around the four corners region and brought showers and thunderstorms to parts of the eastern Cascades and inter-mountain west through July as well. Temperatures were generally around normal and precipitation was above normal in this area.

A large scale low pressure trough over the eastern Pacific Ocean helped keep a high pressure ridge over most of the Northwest U.S. and southern British Columbia through August. The low helped keep moist southwesterly flow over the Olympic Peninsula, which brought more precipitation than normal and cooler temperatures due to cloudy conditions. Southeast Idaho and Northwest Wyoming got above normal precipitation as well due to good monsoonal flow into this region from the desert southwest. The rest of the region saw dry and warm conditions which persisted through the month of September.

Columbia Basin Weather

	Temperature	Precipitation	Precipitation	Precipitation
Location	**Pacific Northwest**	**Columbia River above Coulee**	**Snake River above Ice Harbor**	**Columbia River above The Dalles**
	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 2010	+0.1 / +0.2	60	43	52
August 2010	-0.1 / -0.2	92	94	87
September 2010	+0.4 / +0.7	162	71	137
October 2010	+1.3 / +2.3	93	161	122
November 2010	-0.9 / -1.6	102	106	102
December 2010	+1.0 / +1.8	100	151	113
January 2011	+1.0 / +1.8	144	94	120
February 2011	+0.8 / +1.4	122	75	100
March 2011	-0.1 / -0.2	159	170	173
April 2011	-2.2 / -4.0	151	160	159
May 2011	-1.8 / -3.2	109	151	146
June 2011	-1.2 / -2.2	111	126	112
July 2011	-0.4 / -0.7	103	49	85
August 2011	+1.0 / +1.8	27	60	33
September 2011	+2.6 / +4.7	54	29	45

Stream Flow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 July 2010 through 30 September 2011 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 15-month period for Kootenay Lake, Columbia River at Birchbank, Grand Coulee, and The Dalles, are shown on Charts 9 to12, respectively. Observed and unregulated (USACE) flow hydrographs at The Dalles during the April-July 2011 period, including a plot of flows occurring if regulated only by the four Treaty reservoirs, are provided in Chart 13.

The unregulated August 2010-July 2011 daily average stream flow in the Basin above The Dalles was above average and approximately 51 percent higher than last year's average flow, which was 79% of average. The total runoff volume at The Dalles during this same time period was 204.9 km^3 (166.1 Maf), which is 120 percent of the 1971-2000 average. Month average unregulated inflows during spring runoff were highest at The Dalles in June 2011 at 155 percent of the 1971-2000 June average. The peak-unregulated discharge for the Columbia River at The Dalles was 21767 m^3/s (768.7 kcfs) on 15 June 2011. The 2010-2011 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 Average	Unregulated Flow		Percent of Average
Time Period	cfs	m^3/s		cfs	m^3/s	
Aug-10	81,236	2,300	78	114,186	3,233	83
Sep-10	62,500	1,770	101	93,725	2,654	100
Oct-10	49,734	1,408	111	86,538	2,450	105
Nov-10	49,106	1,391	101	89,204	2,526	94
Dec-10	44,172	1,251	102	96,182	2,724	98
Jan-11	60,484	1,713	144	148,225	4,197	144
Feb-11	42,764	1,211	90	112,123	3,175	92
Mar-11	71,543	2,026	115	161,187	4,564	103
Apr-11	99,186	2,809	81	163,669	4,635	69
May-11	295,686	8,373	111	525,895	14,892	121
Jun-11	440,373	12,470	143	728,236	20,621	155
Jul-11	292,417	8,280	152	428,396	12,131	167
Period Average	**132,838**	**3,762**	**118**	**229,489**	**6,498**	**120**

Seasonal Runoff Forecasts and Volumes

April-August 2011 runoff volumes, adjusted to exclude the effects of regulation of upstream storage, are listed below for eight locations in the Columbia Basin:

Location	Volume in km^3	Volume in Maf	1971-2000 Average in Percent
Libby Reservoir Inflow	9.53	7.73	124%
Duncan Reservoir Inflow	2.78	2.25	110%
Mica Reservoir Inflow	13.74	11.14	99%
Arrow Reservoir Inflow	28.37	23.00	100%
Columbia River at Birchbank	56.07	45.46	112%
Grand Coulee Reservoir Inflow	92.64	75.11	125%
Snake River at Lower Granite	43.17	35.00	153%
Columbia River at The Dalles	157.12	127.38	137%

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2011 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 and 1M. The forecasts for Mica, Arrow, and Duncan inflow were prepared by B.C. Hydro. The forecasts for the lower Columbia River inflows were prepared by the National Weather Service River Forecast Center, 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 2011 forecast of January through July runoff for the Columbia River above The Dalles was 144.3 km^3 (117.0 Maf) and the actual observed runoff was 169.0 km^3 (137.0 Maf).

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

2010 Modified Flows

The 1988 Entity Agreements on Principles and Procedures requires the Entities to use updated estimates of irrigation depletions and return flows when calculating the streamflows required by Treaty Protocol Section VIII for the Steps I, II, and III downstream power benefit studies. These streamflows are unregulated and modified to the same level of net depletions at all modeled projects. The Entities have historically depended on the Pacific Northwest Coordination Agreement process where the streamflow record and depletions are updated every 10 years, except at Grand Coulee where the irrigation depletion estimates are updated annually. The latest PNCA process to update the net depletions and streamflow record to 80 years (1928 to 2009), referred to as the 2010 Modified Flows, was completed in August 2011. Because additional work is needed to update flood control rule curves, hydro-independent and other data dependent on the updated streamflows, the Entities do not expect to incorporate the updated net irrigation depletions in Steps I, II, and III studies until the 2018-19 AOP/DDPB.

Historic Seasonal Runoff Forecasts and Volumes

The Dalles, OR Volume Runoff Forecasts in km^3 (Jan-Jul)							
Year	Jan	Feb	Mar	Apr	May	Jun	Actual
1970	101.8	122.7	115.2	116.3	117.3	--	118.0
1971	136.8	159.7	155.4	165.3	164.1	166.5	169.6
1972	135.8	157.9	171.1	180.2	180.1	180.1	187.1
1973	114.8	111.6	104.5	102.4	99.2	97.1	87.8
1974	151.7	172.7	180.1	183.8	181.3	181.3	192.8
1975	118.5	131.0	141.5	143.9	142.1	139.4	138.6
1976	139.4	143.1	149.3	153.0	153.0	153.0	151.5
1977	93.4	76.7	69.0	71.7	66.4	70.8	66.4
1978	148.0	140.6	133.2	124.6	128.3	129.5	130.3
1979	108.5	97.0	114.7	107.7	110.6	110.6	102.5
1980	109.7	109.7	109.7	110.6	111.8	120.5	118.2
1981	130.7	104.2	104.2	101.0	102.6	118.3	127.5
1982	135.7	148.0	155.4	160.4	161.6	157.9	160.2
1983	135.7	133.2	139.4	149.3	149.3	146.8	146.4
1984	139.4	127.0	120.4	125.8	132.0	140.6	146.9
1985	161.6	134.4	129.5	121.6	121.6	123.3	108.2
1986	119.4	115.1	127.0	130.7	133.2	133.2	133.6
1987	109.7	101.0	96.2	98.7	94.6	93.5	94.4
1988	97.7	92.3	89.7	91.3	93.9	92.5	90.9
1989	124.6	125.8	116.2	122.7	121.6	119.5	111.8
1990	106.7	124.6	128.3	118.4	118.4	122.7	123.0
1991	143.1	135.7	132.0	130.7	130.7	128.3	132.1
1992	114.2	109.9	103.0	87.8	87.8	83.6	86.8
1993	114.2	106.7	95.3	94.5	88.7	106.2	108.5
1994	98.3	94.1	96.3	90.3	93.1	94.2	92.5
1995	124.7	122.9	116.3	122.9	122.9	120.8	128.3
1996	143.1	150.5	160.4	155.4	165.3	173.9	171.8
1997	170.2	178.9	175.2	183.8	188.7	196.1	196.1
1998	106.6	117.4	113.1	112.0	109.9	124.6	128.3
1999	143.1	148.0	160.4	157.9	153.0	151.7	153.1
2000	129.5	130.7	129.5	129.5	129.5	125.8	120.9
2001	99.2	81.9	72.3	69.2	69.7	68.5	71.8
2002	123.3	125.8	120.0	118.9	121.1	123.3	128.0
2003	99.3	93.3	92.4	105.2	111.3	110.1	108.2
2004	127.0	123.3	114.6	103.9	98.1	105.0	102.3
2005	105.6	101.6	87.2	91.0	92.1	98.4	100.3
2006	125.0	137.0	132.0	132.0	136.0	137.0	141.0
2007	129.5	124.6	123.3	123.3	122.2	118.9	118.1
2008	125.8	127.0	127.0	124.6	120.0	121.1	122.4
2009	116.8	114.6	106.3	113.5	112.4	113.5	111.3
2010	109.2	97.7	88.6	86.0	87.5	91.3	104.5
2011	128.3	135.7	134.4	144.3	157.9	173.9	169.0
Minimum	93.4	76.7	69.0	69.2	66.4	68.5	66.4
Median	124.7	124.6	120.2	122.2	121.4	122.7	122.7
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
2011	104.0	110.0	109.0	117.0	128.0	141.0	137.0
Minimum	75.7	62.2	55.9	56.1	53.8	55.5	53.8
Median	101.0	101.0	97.5	99.1	98.4	99.5	99.5
Maximum	138.0	145.0	146.0	149.0	153.0	159.0	159.0

V - RESERVOIR OPERATION

General

The 2010-2011 operating year began with Canadian storage at 82.9 percent full. Libby Reservoir (Lake Koocanusa) was about 5.2 m (17 ft) from full, elevation 744.29 m (2441.9 ft), at the start of the operating year (1 August 2010) and releasing water to meet BiOp objectives for flow augmentation for listed salmon species in the U.S.

The water supply during the 2010-2011 operating year was above 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 115% of normal for January through July 2011. The actual runoff for the overall Columbia basin (U.S. and Canada combined) measured at The Dalles for January through July 2011 was 132% of normal.

The CRTOC signed one operating agreement during the 1 August 2010 to 31 July 2011 operating year (see Section III Operating Arrangements). At the end of the 2010-2011 operating year, Canadian storage was at 99.2 percent on 31 July 2011.

Canadian Storage Operation

At the beginning of the 2010-2011 operating year on 1 August 2010, actual Canadian storage provided under Article II of the Columbia River Treaty (Canadian storage) was at 15.9 km^3 (12.9 Maf) or 82.9 percent full on 31 July 2010. It drafted to a minimum of 2.1 km^3 (1.7 Maf) on 15 April 2011. Canadian composite storage refilled to 18.9 km^3 (15.3 Maf) or 99.2 percent full on 31 July 2011.

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

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

Mica Reservoir

As shown in Chart 5, Mica (Kinbasket) Reservoir was at elevation 747.8 m (2453.3 ft) on 31 July 2010. Basin inflows spiked to a new record high at about 1982 m^3/s (70 000 cfs) on 28 September 2010 and remained relatively high through mid October due to heavy rain. This caused the reservoir to continue to fill to reach a maximum elevation of 753.50 m (2472.1 ft), 0.88 m (2.9 ft) below full pool on 13 October 2010. As is normal, Kinbasket Reservoir was then drawn down during the fall and winter to meet electrical demands. The Upper Columbia generating stations ran relatively hard during the winter of 2010-2011 in order to position the reservoir in anticipation of a large spring runoff volume.

Kinbasket Reservoir reached a minimum elevation of 725.0 m (2378.6 ft) on 6 May 2011, 0.3 m (1.0 ft) higher than the 2010 minimum level of 724.7 m (2377.6 ft) on 10 May 2010. From early May through early July, Mica generation was reduced to near zero as system loads declined and inexpensive market energy was available. Generation was ramped up across July/August to near turbine capacity in August, to slow reservoir refill and minimize spill risks. In response to a significant rain event in late September/early October, the reservoir continued to fill to reach a peak level of 754.17 m (2474.3 ft) on 3 October 2011. The last time the reservoir reached near full was in 2007.

B.C. Hydro sought and received permission from the Comptroller of Water Rights to surcharge the reservoir by 0.3 m (1 ft) up to 2476 ft in September and October for power and flood control purposes. This request is driven by higher than normal inflows into Kinbasket Reservoir this summer. The option to surcharge the reservoir will help minimize spill probabilities and amounts. The surcharge space, however, was not used as extra efforts were made to schedule outages outside the spill risks period such that sufficient turbine capacity was available to pass inflows.

Inflow into Mica Reservoir was 92 percent of normal over the period August to December 2010. Over this same period, Mica outflow varied from a monthly average low of about 223.7 m^3/s (7.9 kcfs) in September to a monthly average high of about 996.8 m^3/s (35.2 kcfs) in December. Inflow into Mica Reservoir was about 96 percent of normal over the period January to July 2011. Outflow over this same period varied from a monthly average high of 979.8 m^3/s (34.6 kcfs) in February to a monthly average low of 17.0 m^3/s (0.6 kcfs) in June.

The Mica project had an under-run of 1349.1 cubic hectometers (hm^3) (551.4 ksfd) on 31 July 2010. The maximum under-run for the operating period was 2151.8 hm^3 (879.5 ksfd) on 8 October 2010, and the minimum under-run (or maximum over-run) was -2139.8 hm^3 (-874.6 ksfd) on 18 March 2011.

The B.C. Hydro Non-Treaty Storage Agreement (NTSA) active storage account was at 2452.8 hm^3 (1002.6 ksfd) on 31 July 2010. The corresponding BPA NTSA account was at 2451.6 hm^3 (1002.1 ksfd) resulting in a combined BPA and B.C. Hydro NTSA storage space at 89 percent full. 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. As of 7 January 2011, both parties completed refill of the remaining NTSA storage space as well as all necessary energy deliveries.

Revelstoke Reservoir

During the 2010-2011 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 (1880.0 ft). During the spring freshet, generally considered to occur within March through July, the reservoir operated as low as elevation 571.65 m (1875.5 ft), or 1.37 m (4.5 ft) below full pool, to provide additional operational space to control high local inflows. Revelstoke 5 went into commercial operation on 22 December 2010. 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 437.54 m (1435.5 ft) on 31 July 2010, 2.59 m (8.5 ft) below full pool. With dry conditions experienced across the entire Columbia basin, Canadian projects operated in proportional draft mode from late summer to early December 2010 to meet Treaty firm loads while balancing the need to refill Mica, Arrow Lakes and Duncan Reservoirs by July/August. Even in proportional draft, Arrow Lakes Reservoir remained relatively high primarily due to Treaty flex operations and the complete refill of the storage volumes managed under the July 1990 Non-Treaty Storage Agreement (NTSA).

Arrow Lakes Reservoir reached a minimum level of 430.59 m (1412.7 feet) on 10 April 2011. By comparison, the Arrow Lakes Reservoir reached a minimum level of 429.00 m (1407.5 ft) on 14 January 2010.

As basin inflows increased from snowmelt runoff, the Arrow Lake Reservoir continued to refill up to its Treaty flood control level (upper rule curve) from April through July 2011. The reservoir reached a maximum elevation for the year of 439.6 m (1442.1 ft), or 0.58 m (1.9 ft) below full pool on 28 July 2011. By comparison in 2010, the Arrow Lakes Reservoir reached a maximum elevation of 439.3 m (1441.3 ft), or 0.82 m (2.7 ft) below full pool on 5 July 2010. The last time the reservoir filled to within 1 ft below full was on 6 July 2008. Arrow Reservoir then drafted across August/September reaching 438.09 m (1437.3 ft) and 436.84 m (1433.2 ft) on 31 August and 30 September 2011, respectively.

Local inflow into Arrow Reservoir was significantly below normal at 75 percent over the period August to December 2010. Arrow outflow varied from a monthly average low of approximately 821.2 m^3/s (29 kcfs) in November to a monthly average high of 1076.0 m^3/s (38 kcfs) in December. Local inflow into Arrow Reservoir was 92 percent of normal over the period January to July 2011. Outflow over this same period varied from a monthly average high of 1529.1 m^3/s (54 kcfs) in July to a monthly average low of 623.0 m^3/s (22 kcfs) in April.

In late November and early December, under terms of the LCA, Canada exercised 137 hm^3 (56 ksfd) of LCA provisional draft. The LCA draft was returned in late January through early February, completing just one cycle for this operating year due to unfavorable market conditions.

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 to provide incubation flows downstream of the Hugh Keenleyside Dam. As a result, from 1 January to 19 January 2011, Arrow outflow was held on average 1415.8 m^3/s (50 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 2011. Arrow outflow, from February through March 2011, was held at 736.2 m^3/s (40 kcfs), on average, to help protect deposited eggs. These flow changes resulted in a Tier 1 protection level for whitefish for the 2010-2011 operating year. During April and May 2011, Arrow outflows were maintained at or above 509.7 m^3/s (18 kcfs) to support 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 levels (and generation) during the January through August period.

A Provisional Storage/Draft Agreement was developed between B.C. Hydro and BPA in October 2010 that comprises three agreements in one (Fall Storage/Release, Provisional Draft/Return, and Spring/Summer Flow Shaping). This Agreement provides both mutually beneficial power and non-power benefits between 16 October 2010 and 31 December 2011 by allowing shaping of Arrow discharges. More specifically, this agreement allows for a shaping of flows for U.S. fisheries from spring to summer and enhanced summer reservoir levels at Arrow.

Duncan Reservoir

Operation of the Duncan Reservoir during the 2010-2011 operating year implemented the operational constraints agreed upon in the Duncan WUP and ordered in the Water License Order (issued on 21 December 2007). As shown in Chart 7, the Duncan Reservoir refilled to 576.04 m (1889.9 ft) or 0.64 m (2.1 ft) below full on 12 August 2010. Duncan discharges were adjusted for the balance of August to target a reservoir elevation of 575.46 m (1888 ft) by the end of August/early September as per the WUP requirements.

After Labor Day, Duncan discharges were increased to maintain Duncan River below the Lardeau confluence (DRL) gauging station at 212.4 m^3/s (7.5 kcfs) maximum to facilitate drafting of the reservoir prior to the start of the kokanee and whitefish spawning downstream of Duncan Dam. For the first three weeks of October, discharges were reduced to maintain a

73 m^3/s (2.6 kcfs) flow at DRL 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). These flows were maintained until 21 December, at which point flows were gradually ramped up to about 249.2 m^3/s (8.8 kcfs) to help support whitefish flows downstream of Keenleyside Dam and to meet month-end Treaty flood control requirements. For the first three weeks of January 2011, Duncan discharge was kept fairly high, near 227 m^3/s (8 kcfs), in order to draft the Duncan Reservoir and to help reduce Arrow flows in aid of whitefish spawning. High basin inflows in February resulted in an increase in reservoir discharge up to 283.2 m^3/s (10 kcfs) in the second half of the month to meet the end of February Treaty flood control target of 1816 ft.

As in most years, Duncan Reservoir was drafted to near empty in late April through to early May. In March/April 2011, flows were significantly reduced due to cold and dry conditions. The project was operated to provide the agreed minimum flow required for fish. Prolonged cold and dry conditions in April, however, necessitated further flows reductions down to natural flows from mid April through early May. For this reason, the Duncan Reservoir reached its minimum license level for the year of 546.9 m (1794.2 ft) on 1 May 2011 and remained near its minimum license level through mid May or until the start of the freshet when project flows were gradually increased with inflows. By comparison, in 2010, the reservoir reached a minimum elevation of 547.1 m (1797.31 ft) on 18 April 2010.

In early June, flows were reduced to the minimum discharge of 3 m^3/s (0.1 kcfs) where they remained through mid July to facilitate reservoir refill. Duncan Reservoir continued to pass the minimum flows until 12 July when discharges were quickly increased to the max flow agreed to for the DRL gauging station (400 m^3/s, 14.1 kcfs) to control the rate of reservoir refill. A significant high inflow event in late July filled Duncan Reservoir to its maximum operating level of 576.7 m (1892 ft) on 31 July 2011. Duncan discharges were increased to above the normal maximum up to 16.8 kcfs (475 m^3/s) at DRL on 5 August 2011.

Duncan Reservoir reached a maximum level of 576.71 m (1892.2 ft) or 0.03 m (0.2 ft) above full on 1 August 2011 with permission from the Water Comptroller. Duncan discharges were adjusted as needed across August through to 5 September (Labor Day) to target a reservoir elevation of ~574.9 +/- 0.3 m (~1886 +/- 1 ft) for the Spillway Operating Gate (SPOG) rehabilitation work starting mid October. The target operation would otherwise have been 575.5 +/- 0.3 m(~1888 +/- 1 ft) on Labor Day.

Libby Reservoir

Operation of Libby Dam and Lake Koocanusa is shown in Chart 8 of this document. Lake Koocanusa began July 2010 at elevation 741.2 m (2431.9 ft), 8.3 m (27.1 ft) from full. Inflow to the reservoir was near 796 m^3/s (28.1 kcfs) at the beginning of July and receded to approximately 340 m^3/s (12.0 kcfs) by the end of the month. Libby released the remaining approved deviation storage of 79 kaf (97.5 hm^3) for sturgeon operations in the first half of July. Outflow from Libby was 391 m^3/s (13.8 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 15 July. Outflow continued at bull trout minimums of 198 m^3/s (7.0 kcfs) in August with Lake Koocanusa reaching a maximum elevation of 744.6 m (2442.9 ft) on 17 August 2010.

To achieve the NOAA Fisheries BiOp September end of month target elevation of 743.4 m (2439.0 ft.), outflow was increased to 227 m^3/s (8 kcfs) from 1 September through 8 September. Outflow was reduced to 198 m^3/s (7.0 kcfs) on 9 September and then increased to 255 m^3/s (9.0 kcfs) on 20 September after inflows increased due to above normal rain events in the basin. A special session of the TMT was convened in September to address the issues of increased inflow and potentially exceeding the end of September elevation without increasing outflows. The consensus of TMT was that maintaining stable flows would be more beneficial biologically than targeting the end of month elevation. To accommodate the preference for stable outflow, outflows were to be held at the rate of 255 m^3/s (9.0 kcfs) until the 743.4 m (2439.0 ft.) target was reached during the first week in October. The end of September elevation was 744.1 m (2441.4 ft.).

Inflows in the first week in October remained abnormally high, and appreciable drafting of the project had not occurred. Based on these events, TMT members decided in a 6 October meeting that the target elevation would not be reached and outflows would be reduced to one unit efficiency of 127 m^3/s (4.5 kcfs), which is near minimum project outflow of 113 m^3/s (4.0 kcfs). The intent of the operation was to conserve water for later release to support power production and chum flows in the Lower Columbia. Ramp down in outflows began on

7 October. By 13 October, outflows at Libby were at the one unit efficiency rate of 127 m^3/s (4.5 kcfs) and were held constant through 8 November. The end of October Lake Koocanusa elevation was 744.2 m (2441.5 ft.).

Outflows from Libby Dam remained at 127 m^3/s (4.5 kcfs) until 8 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 lower on weekends, and higher during the day and lower at night. All changes in outflow followed the ramp rate restrictions as described in the 2006 USFWS BiOp. The average outflow from the dam in November was 292 m^3/s (10.3 kcfs). The reservoir elevation on 30 November was 742.0 m (2434.3 ft).

Daily and weekly load shaping continued at Libby in December, with an average monthly outflow of 515 m^3/s (18.2 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 7.72 km^3 (6.26 Maf), 107 percent of the 1975-2009 average, which required the end of December flood control evacuation requirement to be 2.5 km^3 (2.0 Maf). The project was operated to reach an elevation of 734.9 m (2411 ft) by the end of the month. The actual reservoir elevation on 31 December 2010 was 735.2 m (2412.0 ft).

From January through April, the dam was operated to target end of month elevation following the Libby system VARQ flood control procedures. The January 2011 WSF declined from the previous month to 6.92 km^3 (5.61 Maf), 96 percent of the 1975-2009 average. The resultant end of January upper flood control limit was 739.0 m (2424.5 ft). On 5 January, the project outflow was reduced to the project minimum outflow of 113 m^3/s (4.0 kcfs). The 31 January reservoir elevation was 734.6 m (2410.3 ft).

The February WSF was 8.21 km^3 (6.66 Maf) for the April through August inflow volume, 113 percent of the 1975-2009 average. The end of February flood control upper limit was 729.3 m (2392.7 ft). Due to the increasing forecasts and high reservoir level, Libby Dam releases were ramped up from minimum flow of 113 m^3/s (4.0 kcfs) beginning 2 February, with an average outflow of 411 m^3/s (14.5 kcfs) for the month. The 28 February reservoir elevation was 728.9 m (2391.4 ft.).

The WSF issued in early March for the April through August volume increased again to 8.76 km^3 (7.11 Maf) or 121 percent of the 1975-2009 average, setting the 15 and 31 March flood control upper limits at 720.6 m (2364.3 ft). A forced generation unit outage beginning on 3 March and lasting through 4 May limited the powerhouse hydraulic capacity to four units. March outflows averaged 453 m^3/s (16.0 kcfs). Without full powerhouse capacity, it was not possible to achieve the mid-month flood control elevation target. A deviation was requested and granted for exceeding the mid-month elevation target, while still meeting the end-of-month target. Mid-March Lake Koocanusa elevation was 724.9 m (2378.3 ft.). The 31 March elevation was 720.7 m (2364.5 ft.), less than 0.1 m (0.2 ft.) above the target.

The WSF issued on 5 April for the April through August period volume increased to 8.87 km^3 (7.19 Maf), 123 percent of the 1975-2009 average, setting the 15 and 30 April VARQ flood control upper limits at 719.1 m (2359.2 ft). Starting on 1 April, outflow was reduced to 127 m^3/s (4.5 kcfs), running one turbine unit at the most efficient level for the current lake elevation. Outflow was increased on 5 April to achieve the mid-month elevation target. Outflows averaged 326 m^3/s (11.5 kcfs) from 5 April through 15 April.

Continued above normal snow accumulation occurred in the Kootenai basin during April, with 15 April snow water equivalents in the United States portion of the basin at 141 percent of normal. With the unprecedented snowpack in the basin, Lake Koocanusa was drafted to an end of April elevation of 716.3 m (2349.9 ft.), 2.8 m (9.3 ft.) below the flood control target.

The Corps' May WSF for April-August was 10.07 km^3 (8.17 Maf), 139 percent of the 1975-2009 average. Continued drafting of Lake Koocanusa occurred during the first part of May to provide additional flood space prior to the beginning refill operations. To facilitate drafting, and compensate for the loss of one generator unit in March, one sluice gate was used to release an average of 125 m^3/s (4.4 kcfs) additional spill outflow from 30 April through 9 May. The fifth generator unit was returned to service on 4 May. Total outflows from the project with the sluice gate in operation averaged 646 m^3/s (22.8 kcfs). Outflow from 10 May through 31 May with five generation units in operation averaged 524 m^3/s (18.5 kcfs).

The date of initial control flow (ICF) was declared on 17 May 2011, with Libby then able to begin refill 10 days before on 7 May. Even though established flood control procedures allowed refill to begin on 10 May, Libby Dam was drafted further to try and eliminate as much trapped storage as possible through the first part of May. The minimum elevation of Lake Koocanusa was reached on 12 May at 712.5 m (2337.7 ft.). Outflow was well above the minimum VARQ flow of 343 m^3/s (12.1 kcfs) due to the high seasonal runoff volume forecast. Average May inflow was 776 m^3/s (27.4 kcfs) and the average May outflow was 561 m^3/s (19.8 kcfs). The lake elevation was 721.6m (2367.4 ft.) on 31 May.

The Corps' May official WSF forecast for April through August volume resulted in a Tier 5 sturgeon operation of 1.48 km^3 (1.20 Maf), based on the established 2006 USFWS, as clarified, to provide a volume of water for sturgeon flow augmentation. All forecasts suggested that, given the 180% of average snowpack below the dam, releasing powerhouse capacity should achieve stages within a foot of flood stage at Bonners Ferry to meet the depth attributes. Sturgeon operations would begin as soon as biological criteria had been met, including temperature, and presence of sufficient number of sturgeon in the braided reach below Libby Dam.

The June 2011 WSF remained nearly the same as the previous month at 9.99 km^3 (8.10 Maf) for the April through August volume, 138 percent of average. Libby began the month releasing 651 m^3/s (23.0 kcfs). Accounting for sturgeon operations began on 2 June when criteria mentioned above were met. Because of the high volume conditions, the project operated concurrently throughout June for flood control, sturgeon augmentation volume, and reservoir refill. A prime consideration during the operation was not exceeding the Bonners Ferry flood stage of 537.7 m (1764.0 ft). Peak Bonner Ferry peak stage was reached on 11 June at 537.5 m (1763.4 ft.). Average inflows for June were 1464 m^3/s (51.7 kcfs), with a peak inflow of 1897 m^3/s (67.0 kcfs) on 8 June.

In support of sturgeon operations, from the outset of the operation on 2 June, Libby released near full powerhouse, reducing at times during the peak to not exceed 1764 feet at Bonners Ferry. The highest outflows, averaging 717 m^3/s (25.3kcfs), were held between 10 June and 17 June. On 18 June, flows were ramped down to 566 m^3/s (20 kcfs) and held through 22 June. Flows were reduced on 23 June and held at approximately 481 m^3/s (17 kcfs) through 27 June, then ramped down to 425 m^3/s (15 kcfs) until 11 July, when the 1.48 km^3 (1.20 Maf) sturgeon augmentation volume was expended.

After completion of sturgeon flow augmentation operations, Libby was operated for refill, with outflows constant at 311 m^3/s (11 kcfs) through 26 July. Libby was then ramped up to

396 m^3/s (14 kcfs) through the end of the month, with a 31 July elevation of 747.6 m (2452.8 ft.). The ramp up was in response to an incoming request from the Kootenai Tribe of Idaho to minimize flows in September and October to help with habitat restoration work around Bonners Ferry and to also meet the 30 September target of 2449 ft.

Libby began August with a constant outflow of 396 m^3/s (14 kcfs), and then ramped up to 453 m^3/s (16 kcfs) on 4 August to facilitate the implementation of a Special Operations Request (SOR) approved at the 3 August TMT meeting. The SOR was presented by the Kootenai Tribe for reduced outflows in September and October to allow for habitat improvement work below Libby Dam. This habitat work would be part of the first phase of the Master Plan for the Kootenai River, as coordinated with the Kootenai Conservation and Restoration Plan and the USFWS Bull Trout BiOp. Specifically, the SOR requested a flow of 170 m^3/s (6 kcfs) in September and 113 m^3/s (4 kcfs) in October. TMT members agreed to operate Libby to reach a target elevation of 746.5 m (2449.0 ft.) before 31 August, and reduce outflows to the requested rates thereafter. Libby ramped down to 413 m^3/s (14.6 kcfs) on 15 August due to a unit going out of service for maintenance. Flows were adjusted again, down to 396 m^3/s (14 kcfs) on 27 August, ramped down further on 30 August to 340 m^3/s (12.0 kcfs), and then continued following prescribed ramp-down rates on 31 August with the goal of reducing to the 6 kcfs flow level in early September. The peak elevation at Lake Koocanusa was reached on 4 August at 747.8 m (2453.4 ft.).

Libby ended August at elevation 746.1 m (2447.7 ft.). The flat discharge of 170 m^3/s (6 kcfs) was reached on 5 September and held through the end of September. The 6 kcfs discharge is also the minimum flow required in September for bull trout pursuant to the USFWS Bull Trout BiOp. End of September elevation was 745.8 m (2446.8 ft).

Kootenay Lake

As shown in Chart 9, the level of Kootenay Lake at Queens Bay was at elevation 531.32 m (1743.26 ft) on 31 July 2010. As runoff receded across August, Kootenay Lake began to draft and discharges were adjusted to control reservoir levels slightly below the IJC maximum storage elevations. When the Kootenay Lake level measured at Nelson was drafted below the trigger elevation of 531.36 m (1743.32 ft) on 19 July 2010, discharges were adjusted to keep the lake level at or below the 1743.32 ft control level until the end of August 2010.

Target minimum flows downstream of Brilliant are 509.7 m^3/s (18 kcfs) from December to September and 453.1 m^3/s (16 kcfs) during October and November. These target minimums are subject to water availability. Due to low basin inflows, Brilliant (BRD) and Brilliant Expansion (BRX) projects combined flows were reduced below target in September to prevent further drafting of Kootenay Lake and to conserve water for fish. Further reductions to about 410.6 m^3/s (14.5 kcfs) at BRD/X in late October were required to accommodate a canal dive inspection at Kootenay Canal from 20-24 October 2010. In late November, BRD/X flows were increased to meet target minimum flows. As Libby increased generation in December, there were sufficient flows to support higher releases from BRD/X ranging between 566.3 – 849.5 m^3/s (20 to 30 kcfs). By 31 December 2010, Kootenay Lake was at an elevation of 531.63 m (1744.29 ft), ~0.3 m (~1 ft) below the IJC maximum storage elevations. In January, BRX was out of service and discharges were kept between the minimum target of 18, and the 21 kcfs max BRD discharge. BRD/X projects increased generation across February/March when Kootenay Lake was drafted as required by the IJC rule curve. During this period, Corra Linn was kept in free fall (max release) condition to pass as much water as possible through the hydraulic restriction at Grohman Narrows.

Despite the maximum flows through Grohman Narrows, the Kootenay Lake level exceeded the IJC level on 13 March 2011 and remained above the IJC level until the declaration of spring freshet. This was not a violation of the Kootenay Lake Order, since the gates at Corra Linn were maintained in the fully open (free fall) position. In 2011, the lake reached its annual minimum level of 530.5 m (1740.5 ft) on 24 April 2011. By comparison, in 2010, Kootenay Lake reached a minimum elevation of 529.92 m (1738.6 ft) on 16 April 2010.

The International Kootenay Lake Board of Control, after consultation with FortisBC, declared the Commencement of Spring Rise for Kootenay Lake on 3 May 2011. Following the declaration of spring rise, Kootenay Lake was operated in accordance with the IJC lowering formula. Kootenay Lake discharge was passing the Grohman Narrow maximum flow until the lake receded to below 533.3 m (1749.5 ft) in the first week of July. Lake discharges were adjusted in the spring/summer in response to the high inflows and to control refill of Kootenay Lake. Inflow peaked at 2192 m^3/s (77.4 kcfs) on 8 June 2011. Discharge from the lake peaked at 2455.4 m^3/s (86.7 kcfs) on 24 June 2011. Kootenay Lake reached a peak elevation of 532.97

m (1751.7 ft) on 15 June 2011. By comparison, in 2010, the peak level was 532.97 m (1748.6 ft) on 18 June.

As runoff receded during June, Kootenay Lake began to draft and discharges were adjusted to control lake levels slightly below the IJC limits. When the Kootenay Lake level measured at Nelson was drafted below the trigger elevation of 531.36 m (1743.32 ft) on 27 July 2011, discharges were adjusted to keep the lake level at or below the control level until the end of August.

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 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 2010 as described in the LOP and 2003 CRT FCOP. The December forecast was 99 percent of the 71-year average. Based on this forecast, the recommended draft for Libby Reservoir was 2.47 km^3 (2 Maf), to elevation 734.9 m (2411 ft) on 31 December.

Libby was operated to its VarQ (Variable Flow) flood control storage reservation diagram in December through the spring period. At the end of April, Lake Koocanusa was operated about 9.3 feet below the end of April flood control elevation because estimates of volume forecasts throughout April showed a trend of significantly increasing April through August runoff volumes, indicating a need for deeper reservoir drafts. During the refill period from mid-May through June, Libby Dam operated to manage for downstream flood control and controlled refill. The reservoir filled to within 1.6 m (5.6 feet) of full in August 2011.

Flood Control

The 2011 WSFs averaged significantly above 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 21767 m^3/s (768.7 kcfs) on 15 June 2011, and a regulated daily peak flow of 14113 m^3/s (498.4 kcfs) occurred on 4 June 2011 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 7.77 m (25.5 ft) on 16 June 2011, and the highest observed stage was 5.3 m (17.37 ft) on 1 June 2011, above the NWRFC's flood stage at Vancouver of El. 16 feet.

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; however, the project operations for fish flows and refill were closely monitored to ensure that Arrow's operations would not violate flood control operations downstream. Grand Coulee was operated for flood control and refill was delayed due to the timing of the runoff. As shown in the chart, when compared to the guideline (dashed line), Arrow filled faster relative to Grand Coulee in the beginning of the refill period and then slower towards the end. The horizontal line just prior to 31-July represents drafting of Arrow after filling.

For Duncan, a permanent change to the Storage Reservation Diagram was agreed to and implemented in 2010. The end of February elevation was increased from 1807.7 feet to 1812.5 feet to aid downstream fish interests. The March levels remained unchanged.

In operating year 2010-2011, 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 2011, the computed ICF at The Dalles was 9426 m^3/s (332.9 kcfs) based on the January forecast; 9659 m^3/s (341.1 kcfs) based on the February forecast; 9500 m^3/s (335.5 kcfs) based on the March forecast; 10655 m^3/s (376.3 kcfs) based on the April forecast; and 12789 m^3/s (451.6 kcfs) based on the May forecast. The observed daily peak flow at The Dalles was 14113 m^3/s (498.4 kcfs), and occurred on 4 June 2011. The system was operated for flood risk management in the spring by releasing flows at The Dalles higher than the calculated May ICF in order to manage the river stage at Vancouver. Table 6 shows data for the May ICF computation.

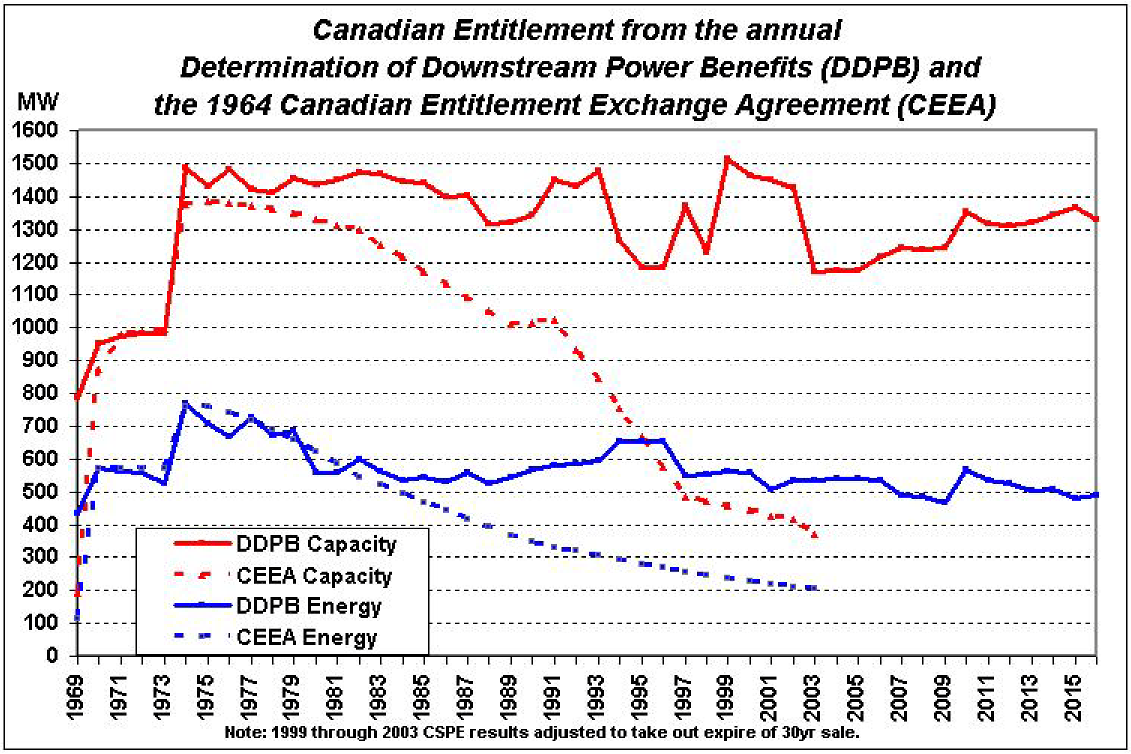
Canadian Entitlement and Downstream Power Benefits

From 1 August 2010 through 30 September 2011, 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, before deductions for transmission losses and scheduling adjustments, are listed in Section III Operating Arrangements of this report, under the heading Canadian Entitlement.

No Entitlement power was disposed directly in the U.S. during 1 August 2010 through 30 September 2011, 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. This load growth difference is the main reason for the large difference in the Canadian Entitlement between the historic DDPBs and the CEEA estimate.

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

2014/2024 Review

During the period of this annual report, the U.S. Entity continued work on the CRT 2014/2024 Review studies. The U.S. CRT 2014/2024 Review Team (Review Team) completed and published the U.S. Entity Supplemental Report in September 2010, a companion report to the CRT Phase 1 Report. The Supplemental Report summarizes the additional studies conducted by the U.S. Entity in which Endangered Species Act (ESA) BiOps and other fish operations were added to the Phase 1 studies to represent how actual system operations may be affected by the various Phase 1 scenarios.

As part of the second phase of the CRT 2014/2024 Review, USACE conducted the Flood Risk Assessment required for the Phase 2 modeling, which included floodplain mapping and surveying, levee assessment, and economic surveying. In addition, USACE continued to work on developing the modeling tools and capabilities to evaluate future Phase 2 studies using a risk based probabilistic approach.

As climate change is recognized as a significant consideration in the Phase 2 studies and in the U.S. Entity recommendation, efforts have been made by the U.S. Entity to be prepared for modeling climate change in the Phase 2 work. This effort has included the development of numerous climate change scenarios and datasets suitable for use in future Phase 2 studies.

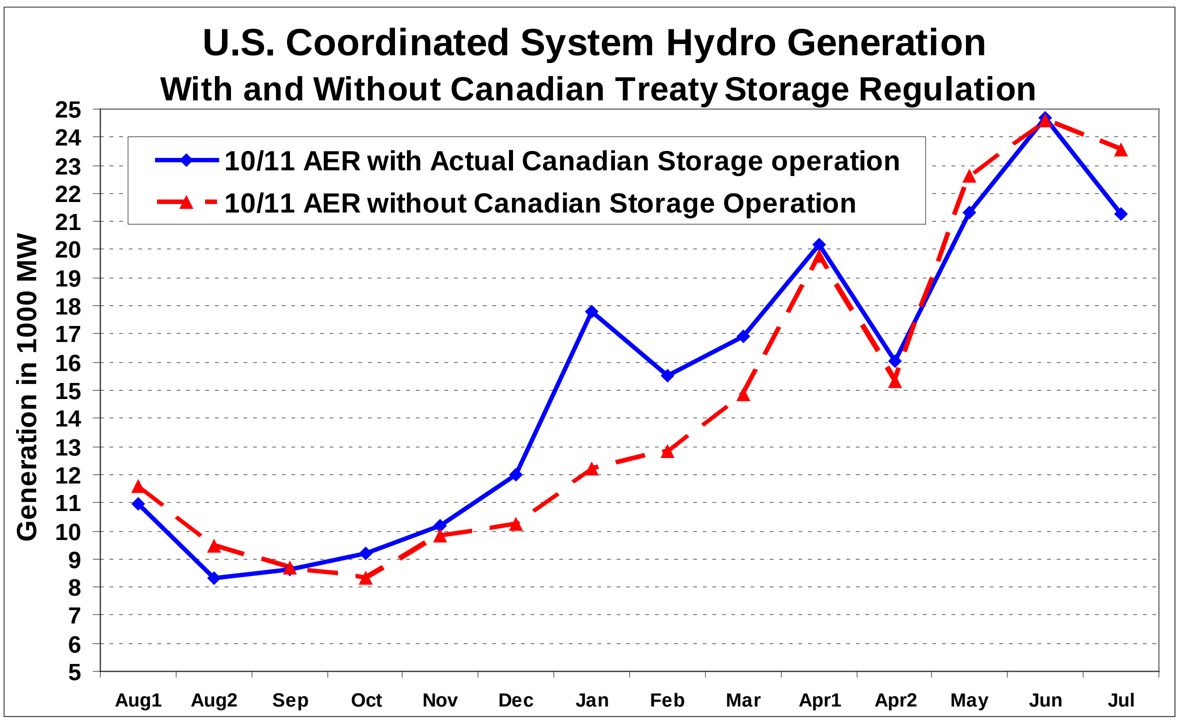
The U.S. Entity initiated a broad regional engagement plan in October 2010. This effort consisted of two approaches. First, the development of a Sovereign Review Team (SRT) composed of the U.S. Entity Coordinators (Co-Chairs), 5 representatives from the 15 U.S. NW Tribes, state representatives for Oregon, Washington, Idaho and Montana and regional representatives from 11 Federal agencies. The purpose of the SRT is to work collaboratively with U.S. Entity to explore possible Treaty futures and seek to inform the U.S. Entity on the development of its recommendation to the Department of State in September 2013. The Sovereign Technical Team serves under the direction of the SRT and provides technical support to the SRT and Review Team through the development and scoping of possible Treaty alternatives, modeling, and analysis. Second, the U.S. Entity has also engaged regional stakeholders during this reporting period through two regional listening sessions, to provide an opportunity for them to learn about the Review process and share their input and suggestions with the U.S. Entity.

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 2010-2011 operating year, with and without the regulation of Canadian storage, based on the PNCA 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 787 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 2010-2011 and 2011-2012 DOPs, the CRTOC completed supplemental operating agreements, described in section III Operating Arrangements, which resulted in power and non-power benefits both in Canada and the U.S. Non-power benefits include changes to stream flows below Arrow that enhanced trout and mountain whitefish spawning in Canada and the downstream migration of salmon in the U.S. The benefits of these regulation improvements were not quantified in this report.

In addition, under the Libby Coordination Agreement, the U.S. received one average annual MW from B.C. Hydro. Canada received the benefits of the provisional draft operation at Arrow and related exchanges of power between B.C. Hydro and BPA, in which Arrow was drafted for a week at the end of November and another week at the beginning of December. B.C. Hydro returned their LCA provisional by the first week in February.

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

Figure 3

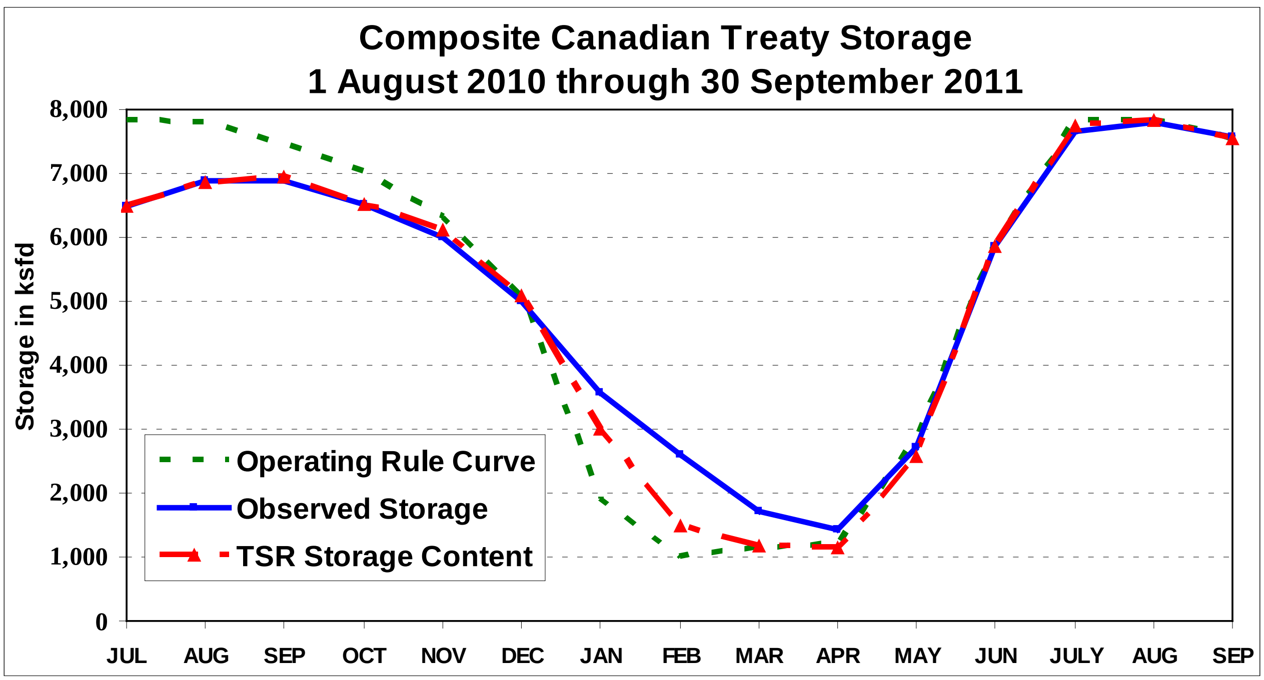


Figure 4 shows the difference in Arrow plus Duncan regulated outflows in the DOP TSR, and the actual daily CRT outflows due to the agreements. The daily unregulated stream flow is also shown for comparison purposes. The large one day increase in unregulated flows at the end of September was caused by large amounts of precipitation in the Mica/Revelstoke area on

28 September 2010. Also note the magnitude and duration of the unregulated flows in May through August due to the above average water supply available this operating year.

Figure 4

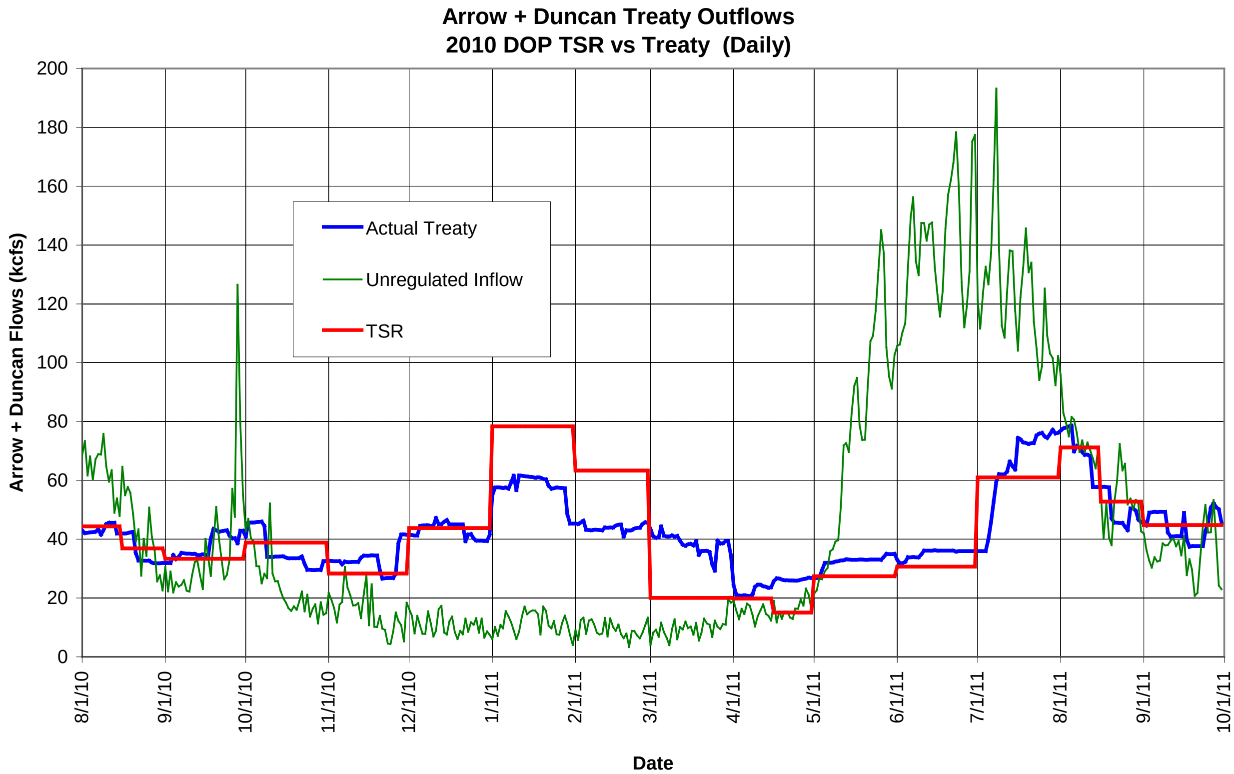


Figure 5 summarizes the Treaty accounting including supplementary operating agreements throughout the year. Section I shows the difference for each period between the final TSR composite storage and the actual Treaty composite storage, including the supplementary agreements. Section II shows the storage 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 9.

Figure 5

Summary of Treaty Storage Operations
July 2010 through September 2011

All units in KSFD	2011							2011										
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)	**6479.6**	**6764.9**	**6845.9**	**6956.2**	**6505.4**	**6120.4**	**5086.0**	**3007.0**	**1495.0**	**1180.0**	**1110.4**	**1131.5**	**2584.2**	**5843.6**	**7752.6**	**7814.6**	**7814.4**	**7544.2**
2) Actual Treaty Content (w/SOA's)	6480.9	6788.0	6887.8	6871.8	6521.4	6001.3	4991.3	3559.6	2586.8	1700.4	1589.2	1441.3	2726.6	5844.1	7667.5	7743.6	7800.6	7546.7
3) % full (actual Treaty/7814.6 ksfd)	82.9%	86.5%	87.6%	89.0%	83.2%	78.3%	65.1%	38.5%	19.1%	15.1%	14.2%	14.5%	33.1%	74.8%	99.2%	100.0%	100.0%	96.5%
4) Final deviation from TSR	**1.3**	**23.1**	**41.9**	**-84.4**	**16.0**	**-119.1**	**-94.7**	**552.6**	**1091.8**	**520.4**	**478.8**	**309.8**	**142.4**	**0.5**	**-85.1**	**-71.0**	**-13.8**	**2.5**

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

	2011							2011										
Balance in each period	**JUL**	**AU1**	**AU2**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**AP1**	**AP2**	**MAY**	**JUN**	**JUL**	**AU1**	**AU2**	**SEP**
5) Libby Coord Agreement (LCA)	0.0	0.0	0.0	0.0	0.0	-28.0	-56.0	-16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6) Non Power Uses Dec Provisional Dra	0.0	0.0	0.0	0.0	0.0	0.0	-28.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7) Non Power Uses Flow (NPU) FA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	504.0	504.0	504.0	504.0	504.0	504.0	504.0	0.0	0.0	0.0	0.0
8) Total	0.0	0.0	0.0	0.0	0.0	-28.0	-84.0	488.0	504.0	504.0	504.0	504.0	504.0	504.0	0.0	0.0	0.0	0.0
9. Inadvertent (Line 4 - Line 8)	**1.3**	**23.1**	**41.9**	**-84.4**	**16.0**	**-91.1**	**-10.7**	**64.6**	**587.8**	**16.4**	**-25.2**	**-194.2**	**-361.6**	**-503.5**	**-85.1**	**-71.0**	**-13.8**	**2.5**
									(NPU avg Feb-Mar)		**(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)

	2011							2011										2011
TSR Date	**JUL**	**AU1**	**AU2**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**AP1**	**AP2**	**MAY**	**JUN**	**JUL**	**AU1**	**AU2**	**SEP**
6-Aug-10	**6479.6**	6773.5	6942.6	6842.2	6328.1	5802.3	4769.4	2637.9	1590.8	965.3	861.8	952.8	2550.9	5797.8	7717.0			
27-Aug-10		**6764.9**	6910.7	6682.5	6061.5	5538.9	4522.5	2391.2	1590.8	895.8	792.3	883.4	2481.4	5728.3	7647.6			
10-Sep-10			**6845.9**	6533.4	6041.4	5503.1	4490.9	2359.5	1590.8	784.6	681.1	772.2	2370.2	5617.2	7536.4			
23-Sep-10				6764.3	6130.3	5523.5	4588.4	2456.9	1590.8	965.3	861.8	952.8	2550.9	5797.8	7717.0			
7-Oct-10				**6956.2**	6585.3	6081.5	5026.5	2895.0	1590.8	1059.7	956.2	1047.2	2645.3	5892.2	7752.6			
21-Oct-10					6540.6	5993.9	4964.9	2833.5	1590.8	1027.6	924.1	1015.2	2613.2	5860.1	7752.6			
5-Nov-10					**6505.4**	6024.4	5053.5	2922.0	1590.8	1039.0	935.5	1026.5	2624.6	5871.5	7752.6			
18-Nov-10						6210.7	5086.0	2964.3	1590.8	1069.3	965.3	1056.4	2654.4	5901.3	7752.6			
9-Dec-10						**6120.4**	4987.4	2860.2	1463.4	1158.9	1010.8	1101.9	2686.5	5906.4	7752.6			
20-Dec-10							5086.0	2937.0	1463.4	1174.5	1010.8	1101.9	2686.5	5906.4	7752.6			
12-Jan-11							**5086.0**	2931.1	1924.9	1095.6	1003.9	1123.0	2670.9	5737.9	7528.8			
24-Jan-11								3008.9	1924.9	1115.2	1017.5	1137.3	2680.9	5742.7	7517.8			
10-Feb-11								**3007.0**	1487.4	1093.7	1102.9	1192.2	2811.6	5987.4	7752.6			
22-Feb-11									1494.6	1093.7	1102.9	1192.2	2833.8	6011.3	7752.6			
10-Mar-11									**1495.0**	1180.0	1151.2	1250.3	2823.6	5949.1	7752.6			
25-Mar-11										1180.0	1159.1	1254.5	2828.7	5952.4	7752.6			
13-Apr-11										**1180.0**	1116.3	1183.7	2787.7	5948.8	7752.6			
22-Apr-11											**1110.4**	1144.3	2703.9	5904.9	7752.6			
11-May-11												**1131.5**	2530.4	5823.1	7752.6			
23-May-11													2609.9	5882.3	7752.6			
10-Jun-11													**2584.2**	5843.6	7752.6			
23-Jun-11														5843.6	7721.6	7814.6	7814.4	
13-Jul-11														**5843.6**	7752.6	7814.6	7814.4	
25-Jul-11															7752.6	7814.6	7814.4	7544.2
8-Aug-11															**7752.6**	7814.6	7814.4	7544.2
25-Aug-11																**7814.6**	7814.4	7544.2
9-Sep-11																	**7814.4**	7544.2
26-Sep-11																		7544.2
6-Oct-11																		**7544.2**

VII – TABLES

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

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

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.28	25.92	13.01	6.92	111.75
February	2.40	27.95	13.84	8.21	114.10
March	2.36	27.55	13.48	8.76	113.85
April	2.46	28.32	13.67	8.87	124.58
May	2.54	28.69	13.70	10.07	139.38
June	2.60	28.91	14.06	9.99	155.42
Actual	2.78	28.37	13.74	9.53	157.12

Table 1: Unregulated Runoff Volume Forecasts Million Acre-feet

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

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	1.85	21.01	10.55	5.61	90.60
February	1.94	22.66	11.22	6.66	92.50
March	1.91	22.33	10.93	7.11	92.30
April	2.00	22.96	11.08	7.19	101.00
May	2.06	23.26	11.10	8.17	113.00
June	2.10	23.43	11.40	8.10	126.00
Actual	2.25	23.00	11.14	7.73	127.38

Table 2M (metric): 2011 Mica Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			11.0	11.6	11.0	10.8	10.4	8.7
PROBABLE DATE-31JULY INFLOW, hm3	**		10970.6	11550.4	10997.5	10806.6	10427.4	8705.0
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/		9165.8	10274.3	9882.4	9778.3	9444.5	7734.5
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		9165.8					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		4022.2					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		3490.9					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		739.9					
JAN31 ORC, m	7/		739.9					
BASE ECC, m	8/	740.0						
LOWER LIMIT, m		732.2						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		8982.5	10068.8				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		3816.7	3816.7				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		3468.7	2382.5				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		739.8	736.8				
FEB28 ORC, m	7/		739.5	736.8				
BASE ECC, m	8/	739.5						
LOWER LIMIT, m		730.1						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		8762.5	9822.2	9645.2			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0			
MIN APR1-JUL31 OUTFLOW, hm3	4/		3589.2	3589.2	3589.2			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		3461.2	2401.5	2578.5			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		739.8	736.9	737.3			
MAR31 ORC, m	7/		739.6	736.9	737.4			
BASE ECC, m	8/	739.6						
LOWER LIMIT, m		729.7						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90.7	90.7	92.5	94.8		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		8313.4	9318.8	9141.2	9269.8		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		3369.0	3369.0	3369.0	3369.0		
VRC APR30 RESERVOIR CONTENT, hm3	5/		3690.1	2684.7	2862.3	2733.7		
VRC APR30 RESERVOIR CONTENT, METERS	6/		740.4	737.6	738.1	737.8		
APR30 ORC, m	7/		740.2	737.6	738.1	737.8		
BASE ECC, m	8/	740.2						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		6581.0	7376.9	7233.9	7333.7	7470.6	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		85.0	85.0	85.0	85.0	85.0	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		3141.4	3141.4	3141.4	3141.4	3141.4	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		5194.9	4399.0	4542.1	4442.3	4305.4	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		744.4	742.3	742.7	742.4	742.1	
MAY31 ORC, m	7/		744.4	742.3	742.7	742.4	742.1	
BASE ECC, m	8/	745.1						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		3336.4	3739.8	3656.5	3706.0	3777.8	3913.6
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		509.7	509.7	509.7	509.7	509.7	509.7
MIN JUL1-JUL31 OUTFLOW, hm3	4/		1820.3	1820.3	1820.3	1820.3	1820.3	1820.3
VRC JUN30 RESERVOIR CONTENT, hm3	5/		7118.5	6715.0	6798.3	6748.8	6677.0	6541.2
VRC JUN30 RESERVOIR CONTENT, METERS	6/		749.2	748.2	748.4	748.3	748.1	747.8
JUN30 ORC, m	7/		749.2	748.2	748.4	748.3	748.1	747.8
BASE ECC, m	8/	751.4						
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: 2011 Mica Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			8893.9	9364.0	8915.7	8761.0	8453.5	7057.2
PROBABLE DATE-31JULY INFLOW, KSFD	**		4484.0	4721.0	4495.0	4417.0	4262.0	3558.0
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/		3746.3	4199.4	4039.2	3996.7	3860.3	3161.3
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		3746.3					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1644.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1426.9					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2427.4					
JAN31 ORC, FT	7/		2427.4					
BASE ECC, FT	8/	2427.9						
LOWER LIMIT, FT		2402.2						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			98.0	98.0				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		3671.4	4115.4				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1560.0	1560.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1417.8	973.8				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2427.2	2417.3				
FEB28 ORC, FT	7/		2426.3	2417.3				
BASE ECC, FT	8/	2426.3						
LOWER LIMIT, FT		2395.5						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.6	95.6	97.6			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		3581.5	4014.6	3942.3			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1467.0	1467.0	1467.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1414.7	981.6	1053.9			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2427.1	2417.5	2419.1			
MAR31 ORC, FT	7/		2426.5	2417.5	2419.1			
BASE ECC, FT	8/	2426.5						
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/		3397.9	3808.9	3736.3	3788.9		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1377.0	1377.0	1377.0	1377.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1508.3	1097.3	1169.9	1117.3		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2429.2	2420.1	2421.7	2420.5		
APR30 ORC, FT	7/		2428.4	2420.1	2421.7	2420.6		
BASE ECC, FT	8/	2428.4						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.8	71.8	73.2	75.0	79.1	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		2689.9	3015.2	2956.7	2997.5	3053.5	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0	3000.0	3000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		1284.0	1284.0	1284.0	1284.0	1284.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2123.3	1798.0	1856.5	1815.7	1759.7	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2442.2	2435.4	2436.7	2435.8	2434.6	
MAY31 ORC, FT	7/		2442.2	2435.4	2436.7	2435.8	2434.6	
BASE ECC, FT	8/	2444.5						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			36.4	36.4	37.0	37.9	40.0	50.6
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1363.7	1528.6	1494.5	1514.7	1544.1	1599.6
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		18000.0	18000.0	18000.0	18000.0	18000.0	18000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		744.0	744.0	744.0	744.0	744.0	744.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2909.5	2744.6	2778.7	2758.5	2729.1	2673.6
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2458.1	2454.9	2455.5	2455.1	2454.5	2453.4
JUN30 ORC, FT	7/		2458.1	2454.9	2455.5	2455.1	2454.5	2453.4
BASE ECC, FT	8/	2465.1						
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): 2011 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			23.0	24.7	23.6	23.5	22.5	17.4
& IN hm3	**		23047.0	24674.0	23592.6	23487.4	22521.0	17449.2
95% FORECAST ERROR FOR DATE, IN hm3			3626.0	2680.3	2333.4	1982.3	1767.6	1660.2
95% CONF.DATE-31JULY INFLOW, hm3	1/		19421.0	21993.7	21259.2	21505.0	20753.4	15788.9
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		19421.0					
MIN FEB1-JUL31 OUTFLOW, hm3	3/		6409.1					
UPSTREAM DISCHARGE, hm3	4/		5143.6					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		889.6					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		422.6					
JAN31 ORC, m	7/		422.6					
BASE ECC, m	8/	430.2						
LOWER LIMIT, m		421.5						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		18974.3	21487.8				
MIN MAR1-JUL31 OUTFLOW, hm3	3/		6066.6	4374.5				
UPSTREAM DISCHARGE, hm3	4/		5264.1	6252.1				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		1114.3	0.0				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		423.2	420.0				
FEB28 ORC, m	7/		423.2	420.0				
BASE ECC, m	8/	430.5						
LOWER LIMIT, m		420.0						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		18411.1	20850.0	20642.7			
MIN APR1-JUL31 OUTFLOW, hm3	3/		5687.4	3995.3	4277.3			
UPSTREAM DISCHARGE, hm3	4/		5247.5	6233.0	6056.1			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		1281.6	42.1	42.4			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		423.7	420.1	420.1			
MAR31 ORC, m	7/		423.7	420.1	420.1			
BASE ECC, m	8/	420.0						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.9	87.9	90.1	92.8		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		17071.0	19332.4	19154.5	19956.7		
MIN MAY1-JUL31 OUTFLOW, hm3	3/		5320.4	3628.3	3910.3	3628.3		
UPSTREAM DISCHARGE, hm3	4/		5032.7	5949.8	5772.3	5900.9		
VRC APR30 RESERVOIR CONTENT, hm3	5/		2039.9	11.5	15.1	11.5		
VRC APR30 RESERVOIR CONTENT, METERS	6/		425.6	420.0	420.0	420.0		
APR30 ORC, Fm	7/		425.6	420.0	420.0	420.0		
BASE ECC, m	8/	431.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		12681.9	14361.9	14222.4	14817.0	15419.8	
MIN JUN1-JUL31 OUTFLOW, hm3	3/		4941.2	3249.1	3531.1	3249.1	3249.1	
UPSTREAM DISCHARGE, hm3	4/		3439.6	4235.5	4092.5	4192.3	4329.2	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		4456.7	2201.9	2245.1	2201.9	2201.9	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		431.3	426.0	426.1	426.0	426.0	
MAY31 ORC, m	7/		431.3	426.0	426.1	426.0	426.0	
BASE ECC, m	8/	436.9						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		5923.4	6708.1	6654.1	6924.6	7222.2	7389.2
MIN JUL1-JUL31 OUTFLOW, hm3	3/		3458.5	2882.1	2978.2	2882.1	2882.1	2882.1
UPSTREAM DISCHARGE, hm3	4/		1516.1	1919.6	1836.2	1885.7	1957.5	2093.4
VRC JUN30 RESERVOIR CONTENT, hm3	5/		7809.1	6851.4	6918.1	6615.1	6615.1	6615.1
VRC JUN30 RESERVOIR CONTENT, METERS	6/		438.3	436.4	436.5	435.9	435.9	435.9
JUN30 ORC, m	7/		438.3	436.4	436.5	435.9	435.9	435.9
BASE ECC, m	8/	439.4						
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: 2011 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			18684.3	20003.3	19126.6	19041.3	18257.8	14146.1
& IN KSFD	**		9420.0	10085.0	9643.0	9600.0	9205.0	7132.0
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/		7937.9	8989.5	8689.3	8789.8	8482.5	6453.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		7937.9					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		2619.6					
UPSTREAM DISCHARGE, KSFD	4/		2102.3					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		363.6					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1386.5					
JAN31 ORC, FT	7/		1386.5					
BASE ECC, FT	8/	1411.3						
LOWER LIMIT, FT		1382.8						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.7	97.7				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		7755.4	8782.7				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		2479.6	1788.0				
UPSTREAM DISCHARGE, KSFD	4/		2151.6	2555.4				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		455.4	0.0				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1388.5	1377.9				
FEB28 ORC, FT	7/		1388.5	1377.9				
BASE ECC, FT	8/	1412.3						
LOWER LIMIT, FT		1377.9						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.8	94.8	97.1			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		7525.2	8522.0	8437.3			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		2324.6	1633.0	1748.3			
UPSTREAM DISCHARGE, KSFD	4/		2144.8	2547.6	2475.3			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		523.8	17.2	17.3			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1390.0	1378.3	1378.3			
MAR31 ORC, FT	7/	1412.8	1390.0	1378.3	1378.3			
BASE ECC, FT	8/	1377.9						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.9	87.9	90.1	92.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		6977.4	7901.8	7829.0	8156.9		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		2174.6	1483.0	1598.3	1483.0		
UPSTREAM DISCHARGE, KSFD	4/		2057.0	2431.9	2359.3	2411.9		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		833.8	4.7	6.2	4.7		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1396.4	1378.0	1378.1	1378.0		
APR30 ORC, FT	7/		1396.4	1378.0	1378.1	1378.0		
BASE ECC, FT	8/	1415.8						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.3	65.3	66.9	68.9	74.3	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		5183.5	5870.1	5813.1	6056.1	6302.5	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		2019.6	1328.0	1443.3	1328.0	1328.0	
UPSTREAM DISCHARGE, KSFD	4/		1405.9	1731.2	1672.7	1713.5	1769.5	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		1821.6	900.0	917.6	900.0	900.0	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1415.1	1397.7	1398.1	1397.7	1397.7	
MAY31 ORC, FT	7/		1415.1	1397.7	1398.1	1397.7	1397.7	
BASE ECC, FT	8/	1433.5						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.5	30.5	31.3	32.3	34.8	46.8
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		2421.1	2741.8	2719.7	2830.3	2951.9	3020.2
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		1413.6	1178.0	1217.3	1178.0	1178.0	1178.0
UPSTREAM DISCHARGE, KSFD	4/		619.7	784.6	750.5	770.7	800.1	855.6
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3191.8	2800.4	2827.6	2703.8	2703.8	2703.8
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1438.0	1431.8	1432.2	1430.2	1430.2	1430.2
JUN30 ORC, FT	7/		1438.0	1431.8	1432.2	1430.2	1430.2	1430.2
BASE ECC, FT	8/	1441.5						
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): 2011 Duncan Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			2.0	2.1	2.0	2.0	2.0	1.6
& IN hm3	**		1989.1	2077.2	2006.2	2025.8	1998.9	1563.4
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/		1679.3	1821.1	1750.2	1794.5	1788.2	1373.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		1679.3					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		152.3					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		199.7					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		551.9					
JAN31 ORC, m	7/		553.5					
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/		1647.4	1786.5				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		145.4	142.4				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		224.8	82.7				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		552.4	549.2				
FEB28 ORC, m	7/		552.4	549.2				
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/		1607.1	1742.8	1708.2			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8			
MIN APR1-JUL31 OUTFLOW, hm3	4/		137.8	134.8	135.3			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		257.5	118.8	154.0			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		553.1	550.1	550.9			
MAR31 ORC, m	7/		553.1	550.1	550.9			
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/		1506.4	1633.5	1603.1	1683.3		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8	2.8		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		130.5	127.5	128.0	127.5		
VRC APR30 RESERVOIR CONTENT, hm3	5/		350.9	220.7	251.6	171.0		
VRC APR30 RESERVOIR CONTENT, METERS	6/		554.9	552.3	553.0	551.0		
APR30 ORC, m	7/		554.9	552.3	553.0	551.0		
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/		1133.6	1229.3	1207.6	1266.9	1346.6	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		2.8	2.8	2.8	2.8	2.8	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		122.9	119.9	120.4	119.9	119.9	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		716.2	617.4	639.6	579.8	500.1	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		561.4	559.7	560.1	559.1	557.7	
MAY31 ORC, m	7/		561.4	559.7	560.1	559.1	557.7	
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/		545.8	591.9	582.8	610.1	649.1	662.0
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		17.0	17.0	17.0	17.0	17.0	17.0
MIN JUL1-JUL31 OUTFLOW, hm3	4/		78.9	75.8	76.4	75.8	75.8	75.8
VRC JUN30 RESERVOIR CONTENT, hm3	5/		1259.9	1210.8	1220.4	1192.5	1153.5	1140.7
VRC JUN30 RESERVOIR CONTENT, METERS	6/		569.9	569.2	569.4	568.9	568.4	568.2
JUN30 ORC, m	7/		569.9	569.2	569.4	568.9	568.4	568.2
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: 2011 Duncan Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			1612.6	1684.0	1626.4	1642.3	1620.5	1267.4
& IN KSFD	**		813.0	849.0	820.0	828.0	817.0	639.0
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/		686.4	744.3	715.3	733.5	730.9	561.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		686.4					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		62.2					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		81.6					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1810.6					
JAN31 ORC, FT	7/		1815.8					
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/		673.4	730.2				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		59.4	58.2				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		91.9	33.8				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1812.3	1801.8				
FEB28 ORC, FT	7/		1812.3	1801.8				
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/		656.9	712.3	698.2			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		56.3	55.1	55.3			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		105.3	48.6	62.9			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1814.5	1804.7	1807.3			
MAR31 ORC, FT	7/		1814.5	1804.7	1807.3			
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/		615.7	667.7	655.3	688.0		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0	100.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		53.3	52.1	52.3	52.1		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		143.4	90.2	102.9	69.9		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1820.5	1812.0	1814.1	1807.9		
APR30 ORC, FT	7/		1820.5	1812.0	1814.1	1807.9		
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/		463.3	502.4	493.6	517.8	550.4	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0	100.0	100.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		50.2	49.0	49.2	49.0	49.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		292.7	252.4	261.4	237.0	204.4	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1841.9	1836.4	1837.7	1834.3	1829.7	
MAY31 ORC, FT	7/		1841.9	1836.4	1837.7	1834.3	1829.7	
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/		223.1	241.9	238.2	249.4	265.3	270.6
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		600.0	600.0	600.0	600.0	600.0	600.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		32.2	31.0	31.2	31.0	31.0	31.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		515.0	494.9	498.8	487.4	471.5	466.2
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1869.9	1867.5	1868.0	1866.6	1864.7	1864.0
JUN30 ORC, FT	7/		1869.9	1867.5	1868.0	1866.6	1864.7	1864.0
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): 2011 Libby Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			7.0	8.2	8.7	8.8	9.9	9.9
PROBABLE DATE-31JULY INFLOW, hm3			7038.4	8244.6	8717.0	8833.0	9927.1	9853.2
95% FORECAST ERROR FOR DATE, hm3			1769.6	1306.2	1210.8	1082.6	972.8	850.4
OBSERVED JAN1-DATE INFLOW, IN hm3			0.0	270.1	483.4	756.2	1124.9	3198.4
95% CONF.DATE-31JULY INFLOW, hm3	1/		5268.8	6668.5	7022.7	6994.3	7829.4	5804.3
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		5105.3					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		2922.7					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		3959.6					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		736.8					
JAN31 ORC, m	7/		736.8					
BASE ECC, m	9/	737.1						
LOWER LIMIT, m		717.9						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		4957.8	6474.9				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		2648.7	2321.8				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		3833.1	1989.1				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		735.9	721.1				
FEB28 ORC, m	7/		735.9	721.1				
BASE ECC, m	9/	736.2						
LOWER LIMIT, m		710.8						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.6	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		4773.6	6234.9	6762.9			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3			
MIN APR1-JUL31 OUTFLOW, hm3	4/		2345.3	2018.4	2073.0			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		3713.9	1925.7	1452.1			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		735.1	720.5	715.7			
MAR31 ORC, m	7/		735.1	720.5	715.7			
BASE ECC, m	9/	735.4						
LOWER LIMIT, m		700.0						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.3	85.0	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		4336.1	5668.0	6144.9	6357.7		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		113.3	113.3	113.3	113.3		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		2051.7	1724.9	1779.4	1724.9		
VRC APR30 RESERVOIR CONTENT, hm3	5/		3857.8	2199.0	1776.5	1509.3		
VRC APR30 RESERVOIR CONTENT, METERS	6/		736.1	723.0	719.0	716.3		
APR30 ORC, m	7/		734.4	723.0	719.0	716.3		
BASE ECC, m	9/	734.4						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.1	57.0	58.6	60.9	67.0	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		2903.1	3801.0	4115.4	4259.5	5245.8	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		305.8	226.5	239.8	226.5	226.5	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		1748.3	1421.5	1476.0	1421.5	1421.5	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		4987.4	3762.6	3502.8	3304.1	2317.9	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		743.1	735.5	733.7	732.2	724.1	
MAY31 ORC, m	7/		739.9	735.5	733.7	732.2	724.1	
BASE ECC, m	9/	733.3						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.6	20.4	20.9	21.8	23.9	35.8
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		1032.7	1360.3	1467.7	1524.7	1871.2	2077.9
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		356.8	311.5	319.0	311.5	28.3	311.5
MIN JUL1-JUL31 OUTFLOW, hm3	4/		955.6	834.3	854.6	834.3	834.3	834.3
VRC JUN30 RESERVOIR CONTENT, hm3	5/		6065.1	5616.2	5528.8	5451.8	5105.3	4898.6
VRC JUN30 RESERVOIR CONTENT, METERS	6/		749.1	746.6	746.2	745.7	743.8	742.6
JUN30 ORC, m	7/		749.1	746.6	746.2	745.7	743.8	742.6
BASE ECC, m	9/	739.9						
JUL 31 ORC, m			749.5	749.5	749.5	749.5	749.5	749.5
JAN1-JUL31 FORECAST,-EARLYBIRD, km3	8/		128.3	135.7	134.5	144.3	157.9	173.9

1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW) MINUS OBSERVED INFLOW.
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (2510.5 KSFD) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143
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: 2011 Libby Reservoir Variable Refill Curve

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE JAN-31JULY INFLOW, KAF			5706	6684	7067	7161	8048	7988
PROBABLE JAN-31JULY INFLOW, KSFD			2876.8	3369.8	3562.9	3610.3	4057.5	4027.3
95% FORECAST ERROR FOR DATE, KSFD			723.3	533.9	494.9	442.5	397.6	347.6
OBSERVED JAN1-DATE INFLOW, IN KSFD			0	110.4	197.6	309.1	459.8	1307.3
95% CONF.DATE-31JULY INFLOW, KSFD	1/		2153.5	2725.6	2870.4	2858.8	3200.1	2372.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		2086.7					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4000					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1194.6					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1618.4					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2417.2					
JAN31 ORC, FT	7/		2417.2					
BASE ECC, FT	9/	2418.2						
LOWER LIMIT, FT		2355.4						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		2026.4	2646.5				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1082.6	949				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1566.7	813				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2414.4	2365.8				
FEB28 ORC, FT	7/		2414.4	2365.8				
BASE ECC, FT	9/	2415.5						
LOWER LIMIT, FT		2331.9						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.6	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		1951.1	2548.4	2764.2			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000	4000			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		958.6	825	847.3			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1518	787.1	593.5			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2411.8	2363.8	2348.1			
MAR31 ORC, FT	7/		2411.8	2363.8	2348.1			
BASE ECC, FT	9/	2412.7						
LOWER LIMIT, FT		2296.5						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.3	85	87.5	90.9		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		1772.3	2316.7	2511.6	2598.6		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000	4000	4000		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		838.6	705	727.3	705		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1576.8	898.8	726.1	616.9		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2414.9	2372.2	2359	2350.1		
APR30 ORC, FT	7/		2409.4	2372.2	2359	2350.1		
BASE ECC, FT	9/	2409.4						
		2287.8						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.1	57	58.6	60.9	67	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		1186.6	1553.6	1682.1	1741	2144.1	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		10800	8000	8466.7	8000	8000	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		714.6	581	603.3	581	581	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2038.5	1537.9	1431.7	1350.5	947.4	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2437.9	2412.9	2407	2402.3	2375.7	
MAY31 ORC, FT	7/		2427.4	2412.9	2407	2402.3	2375.7	
BASE ECC, FT	9/	2405.8						
		2287.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.6	20.4	20.9	21.8	23.9	35.8
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		422.1	556	599.9	623.2	764.8	849.3
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		12600	11000	11266.7	11000	1000	11000
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		390.6	341	349.3	341	341	341
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2479	2295.5	2259.8	2228.3	2086.7	2002.2
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2457.6	2449.6	2448	2446.6	2440.2	2436.2
JUN30 ORC, FT	7/		2457.6	2449.6	2448	2446.6	2440.2	2436.2
BASE ECC, FT	9/	2427.4						
		2287.0						
JUL 31 ORC, FT			2459	2459	2459	2459	2459	2459
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		104	110	109	117	128	141

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 2011

Upstream Storage Corrections km^3 and Maf	Metric (km^3)		English (Maf)	
Mica	8.469		6.866	
Arrow	4.441		3.600	
Duncan	1.723		1.397	
Libby	4.640		3.761	
Hungry Horse	2.029		1.645	
Flathead Lake	0.617		0.500	
Noxon Rapids	0.000		0.000	
Pend Oreille Lake	0.617		0.500	
Grand Coulee	5.688		4.612	
Brownlee	0.837		0.678	
Dworshak	2.424		1.965	
John Day	0.195		0.158	
Total Upstream Storage Corrections	31.679		25.682	
1-May Forecast of TDA May – August Runoff Volume, Maf		120.388		97.600
Less Estimated Depletions		-2.061		-1.671
Less Total Upstream Storage Corrections		-31.679		-25.682
Forecast of Adjusted Residual Runoff Volume		86.648		70.247
Computed Initial Controlled Flow from Chart 1 of the Flood Control Operating Plan, km^3/s and kcfs		137.661		452

VIII - CHARTS

Chart 1: Pacific Northwest Monthly Temperature Departures October – March

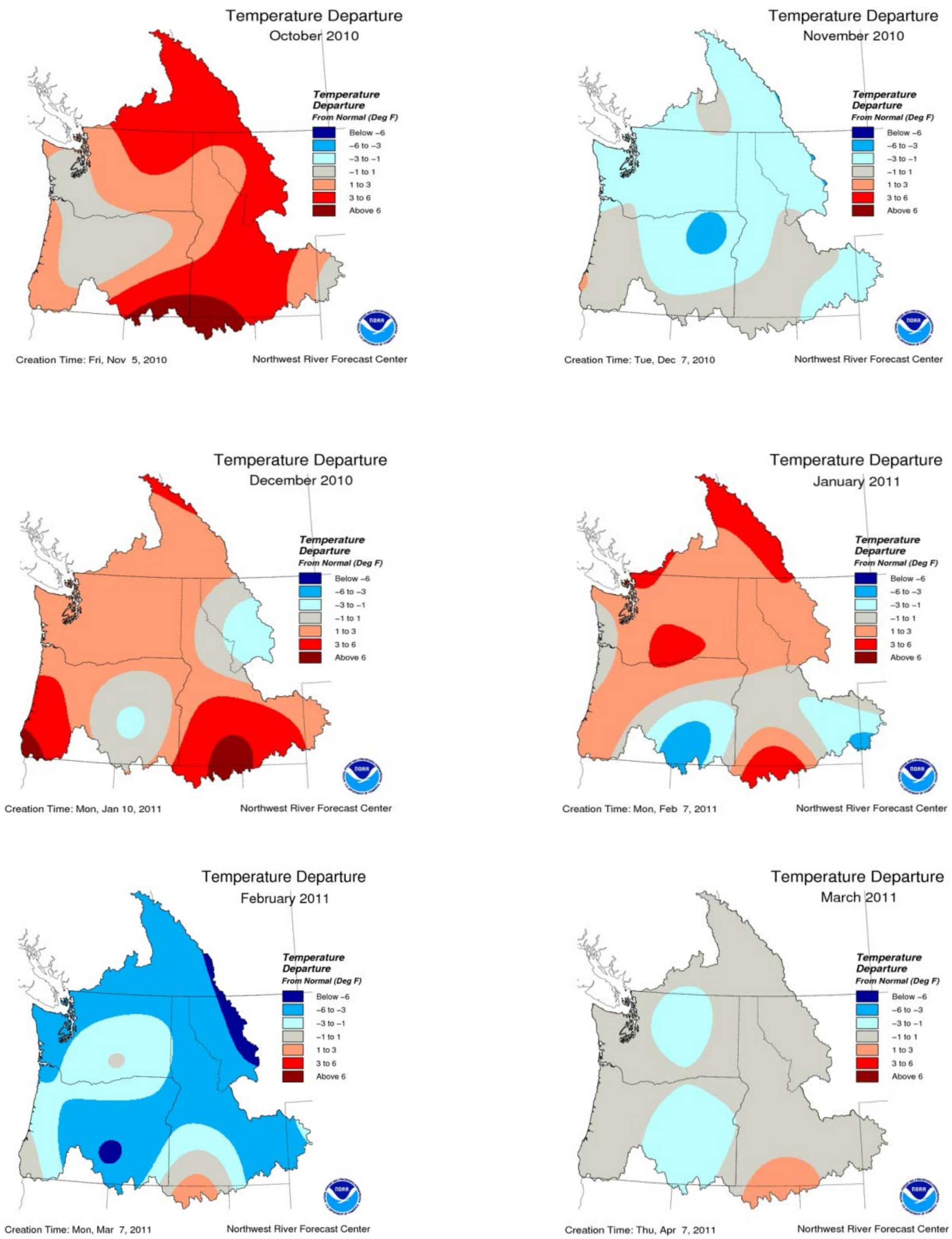


Chart 1: Pacific Northwest Monthly Temperature Departures (Continued)

April – September

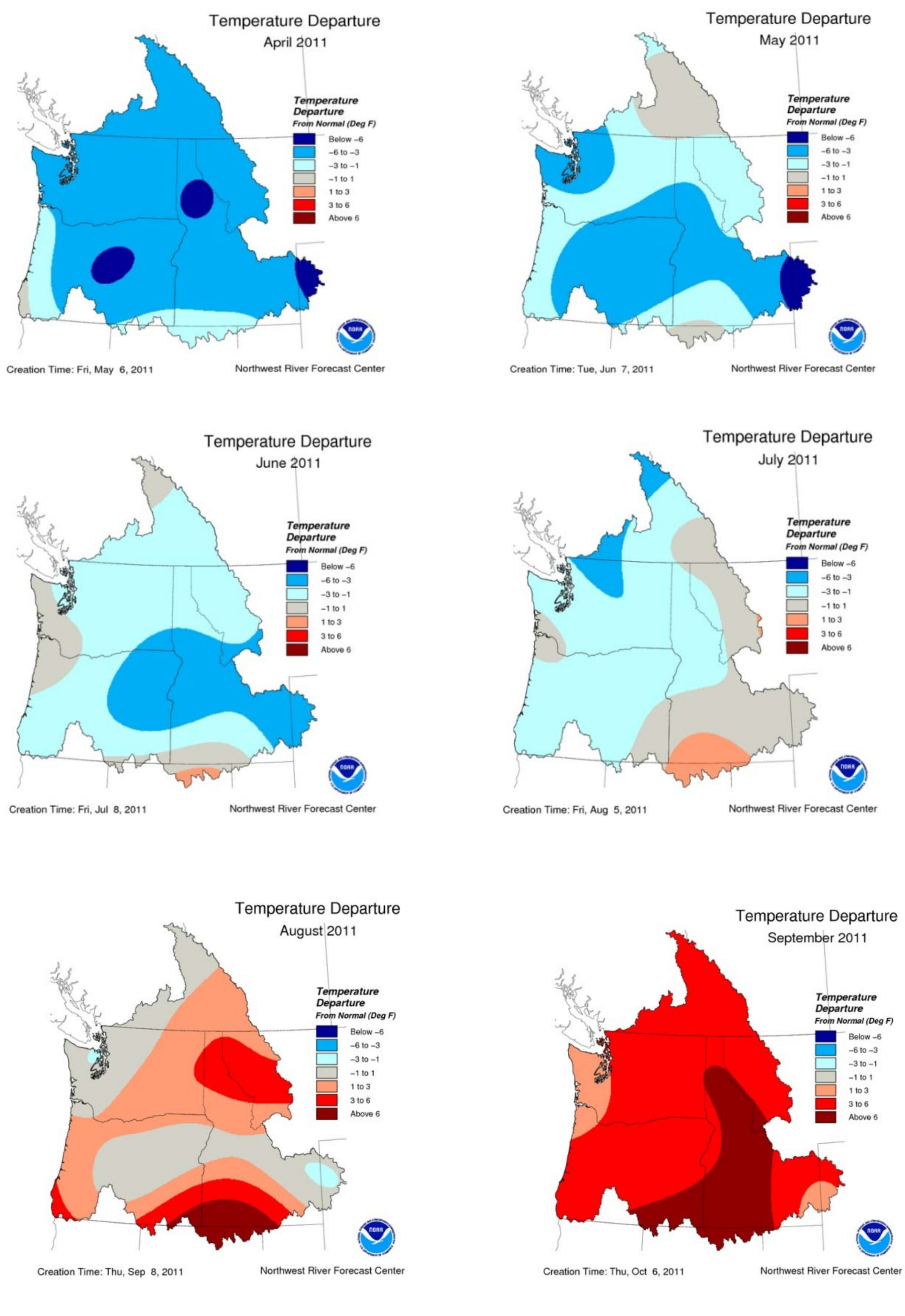


Chart 2: Seasonal Precipitation

Columbia River Basin

October 2010 – September 2011

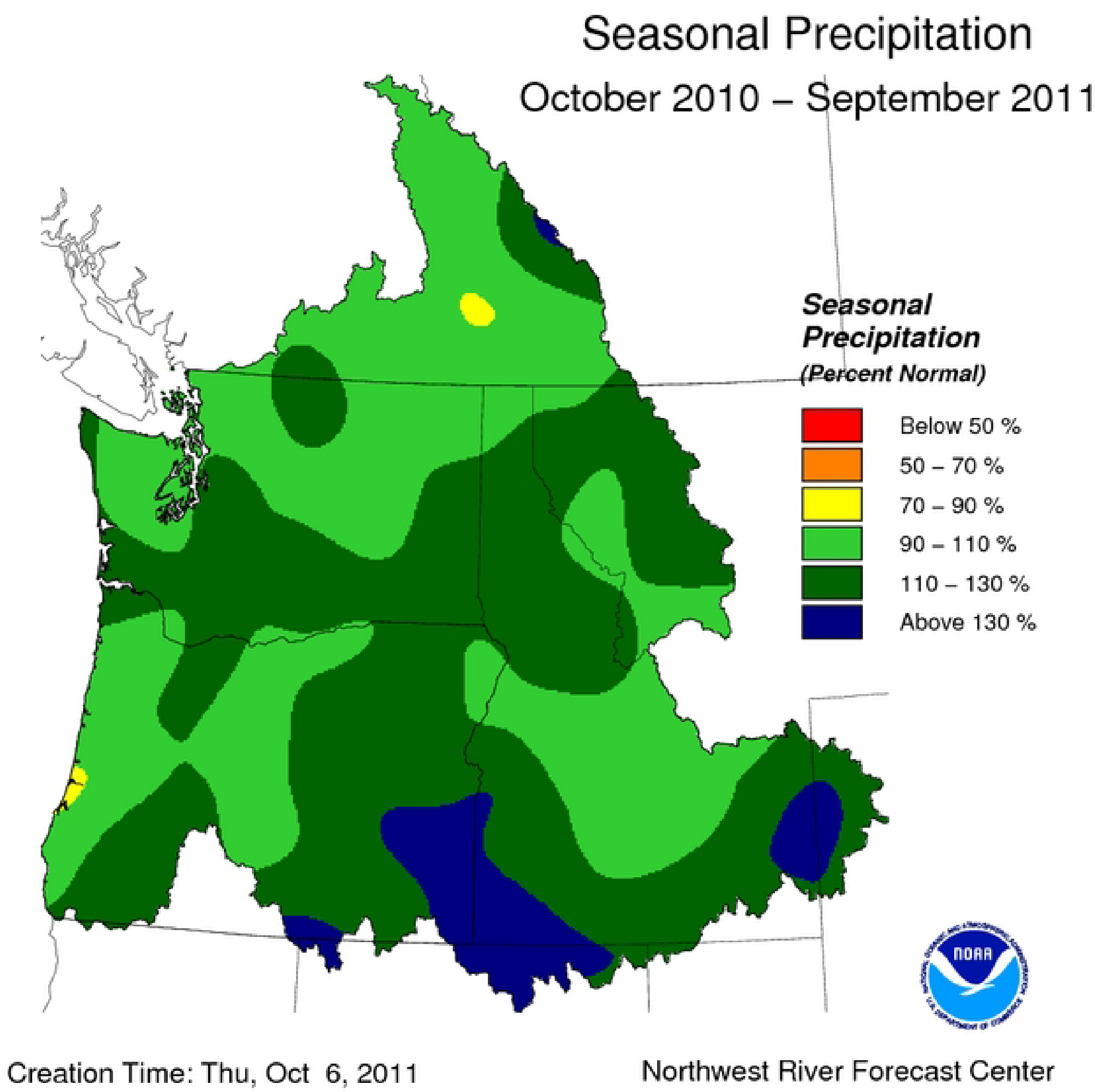
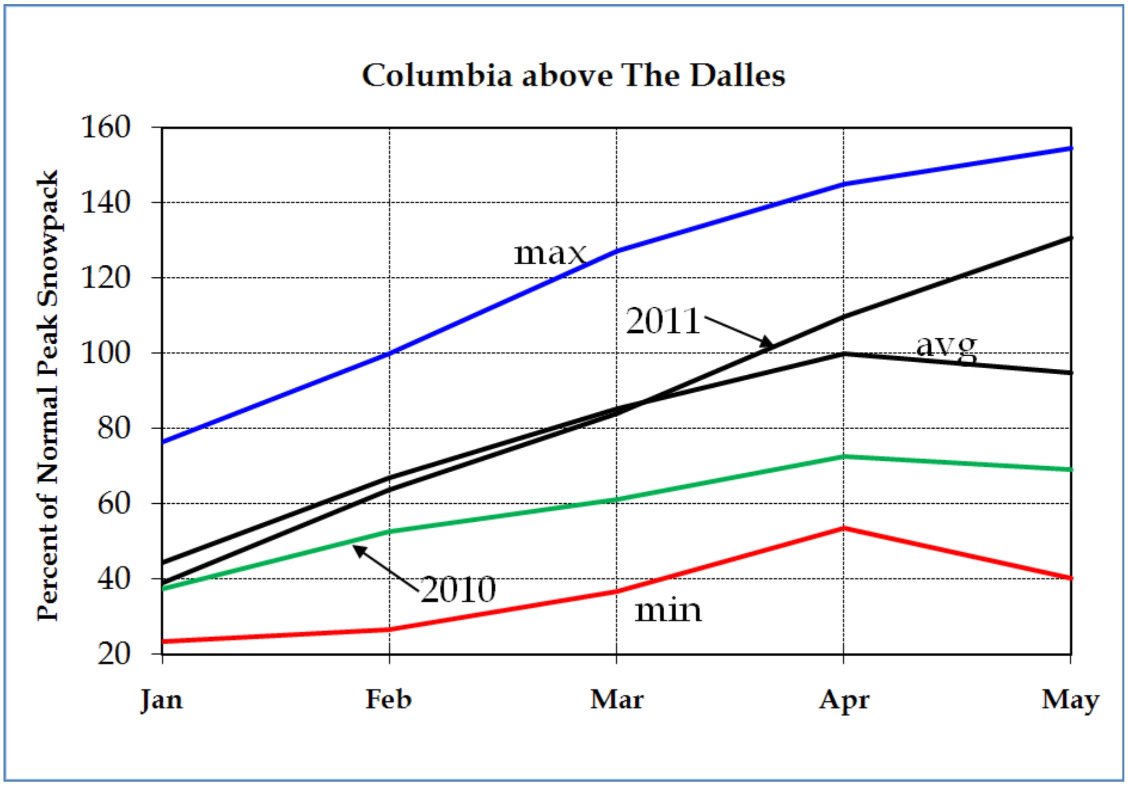


Chart 3: Columbia Basin Snowpack



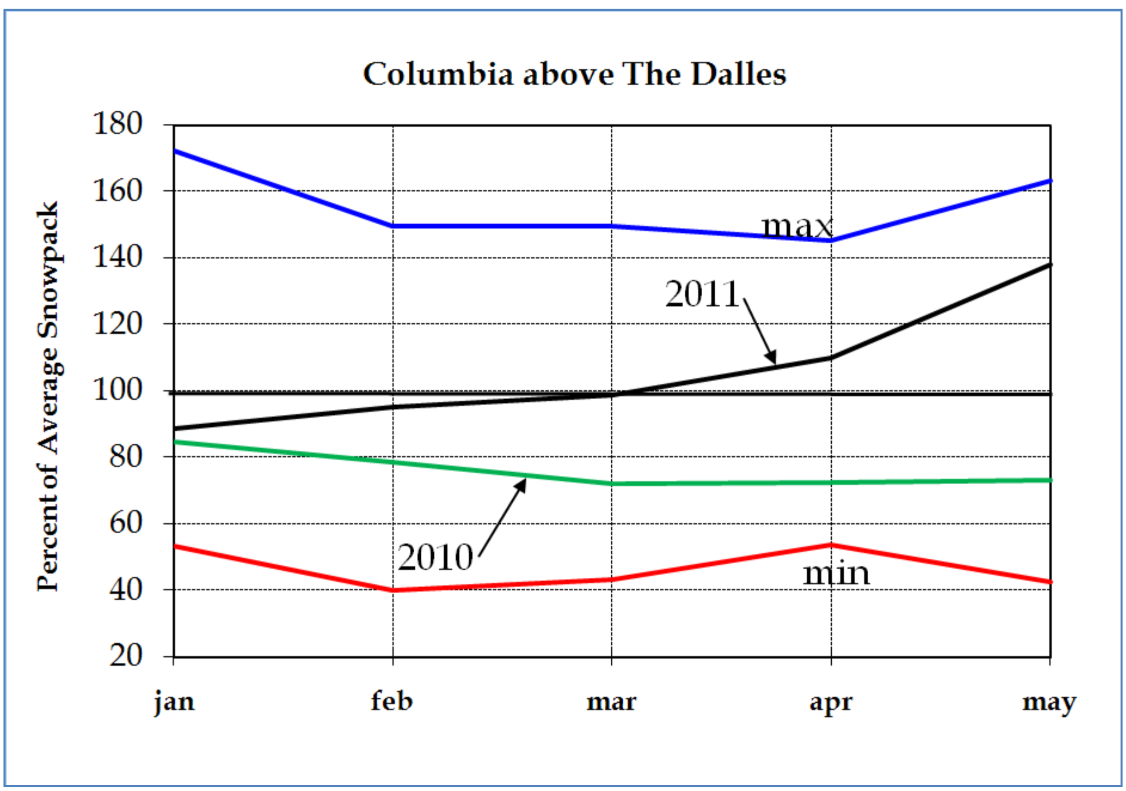


Chart 4: Accumulated Precipitation for WY 2011

At Primary Columbia River Basins

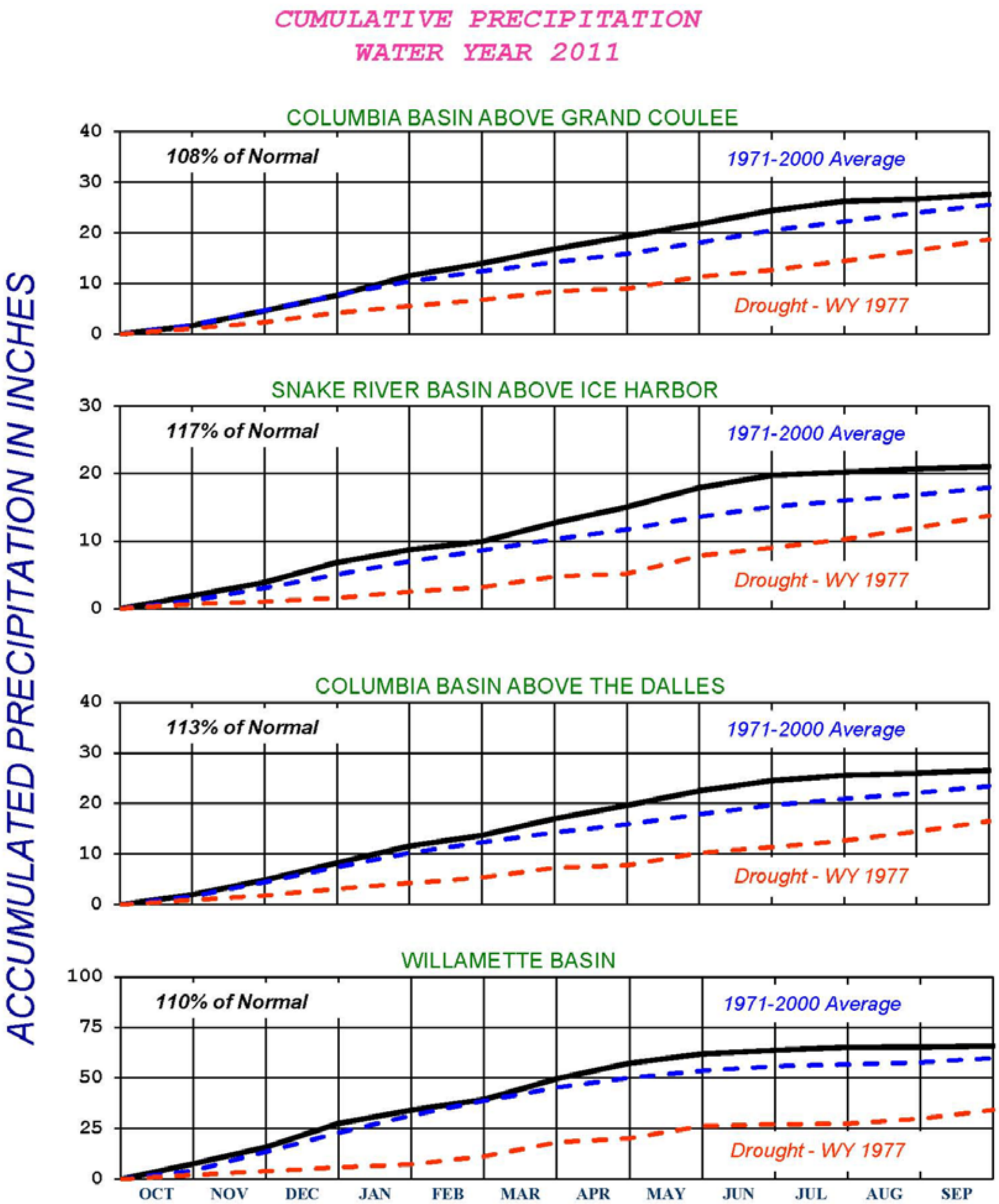


Chart 5: Regulation of Mica

1 July 2010 – September 2011

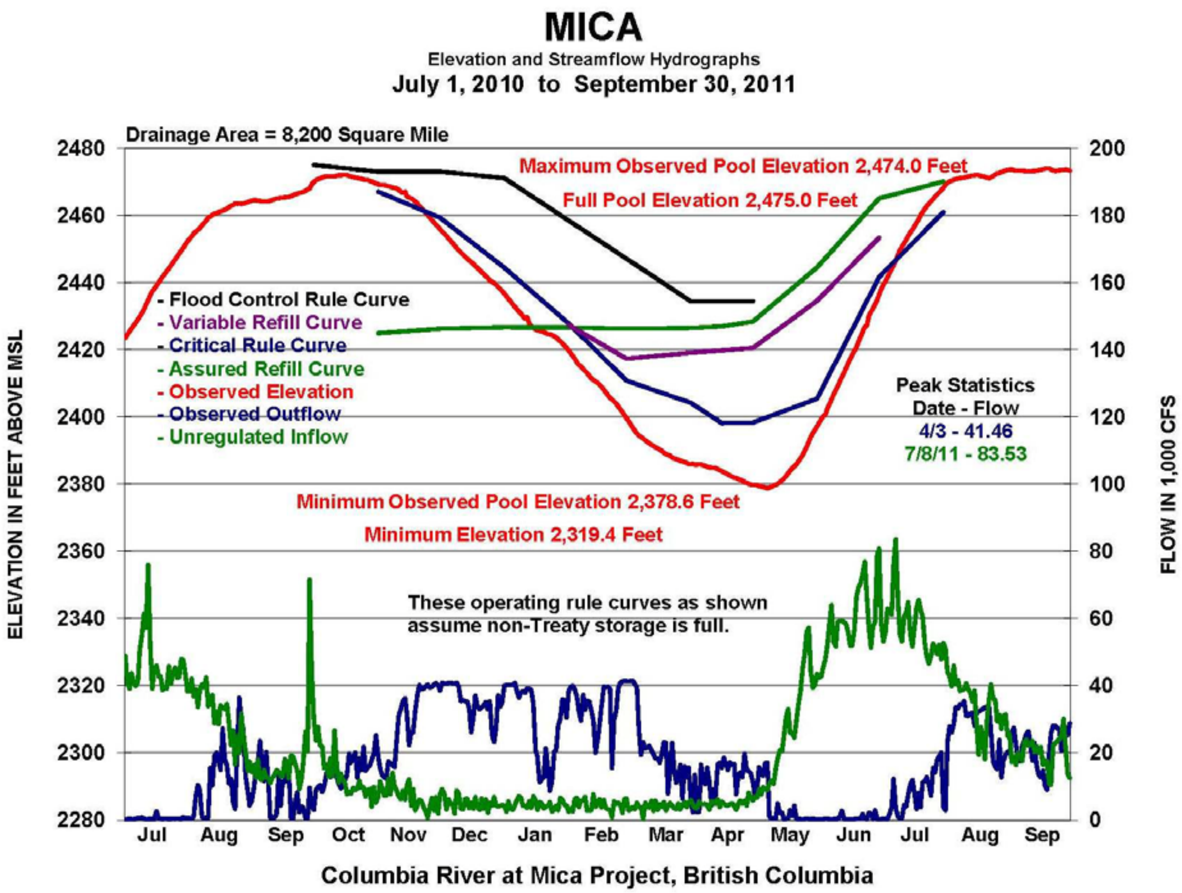


Chart 6: Regulation of Arrow

1 July 2010 – September 2011

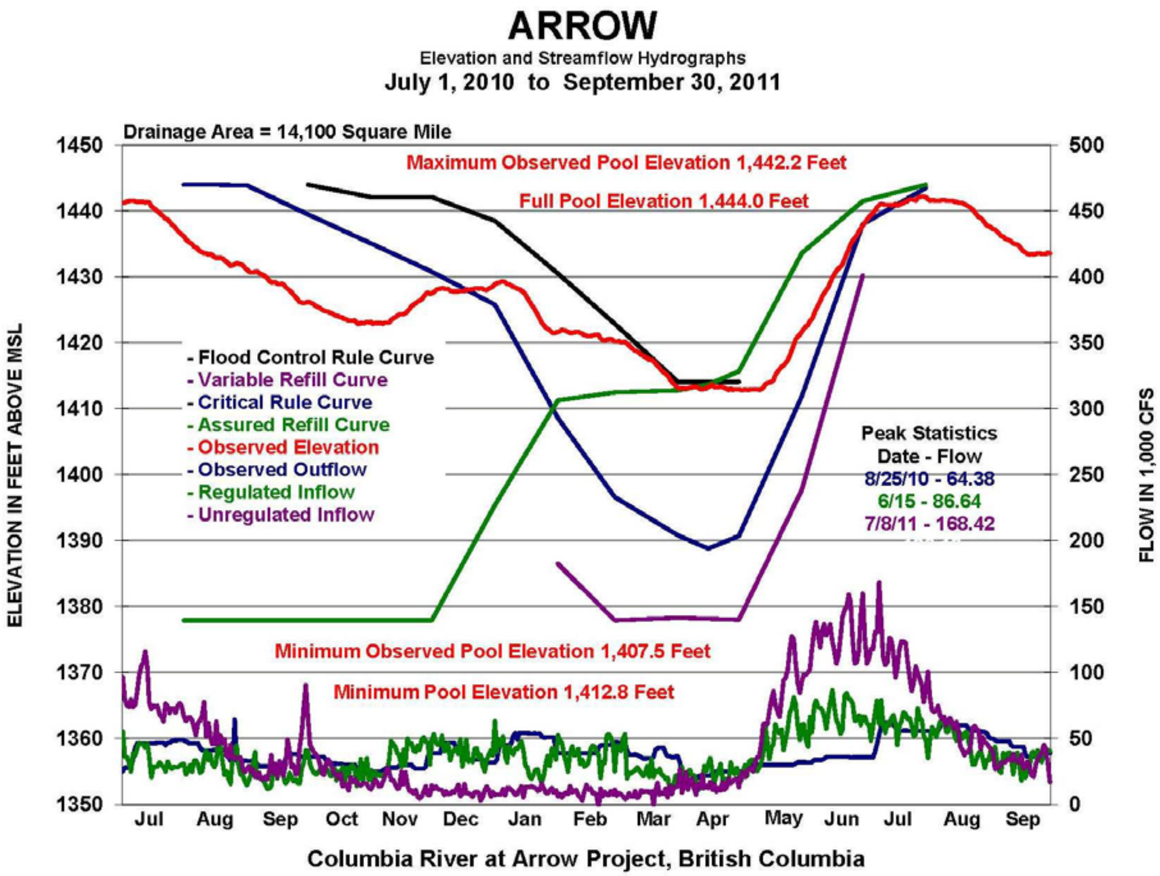


Chart 7: Regulation of Duncan

1 July 2010 – September 2011

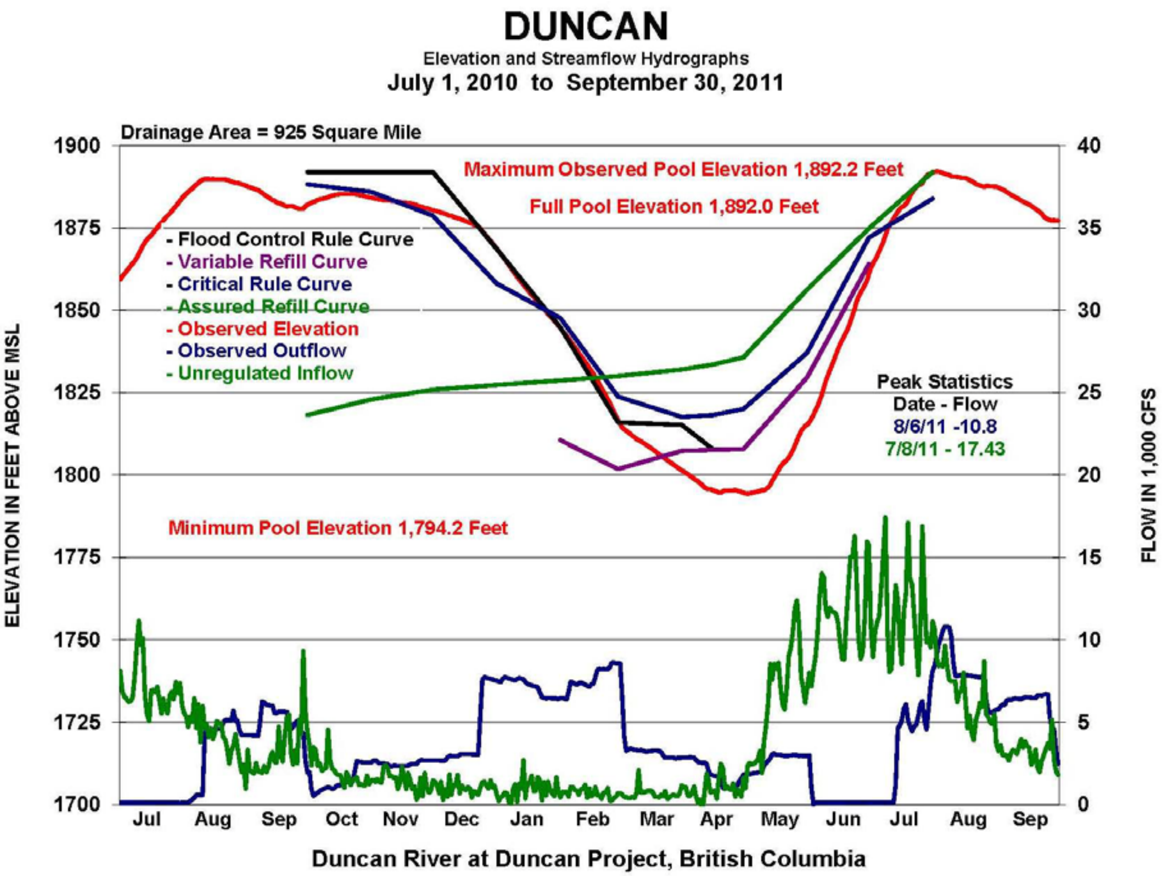


Chart 8: Regulation of Libby

1 July 2010 – September 2011

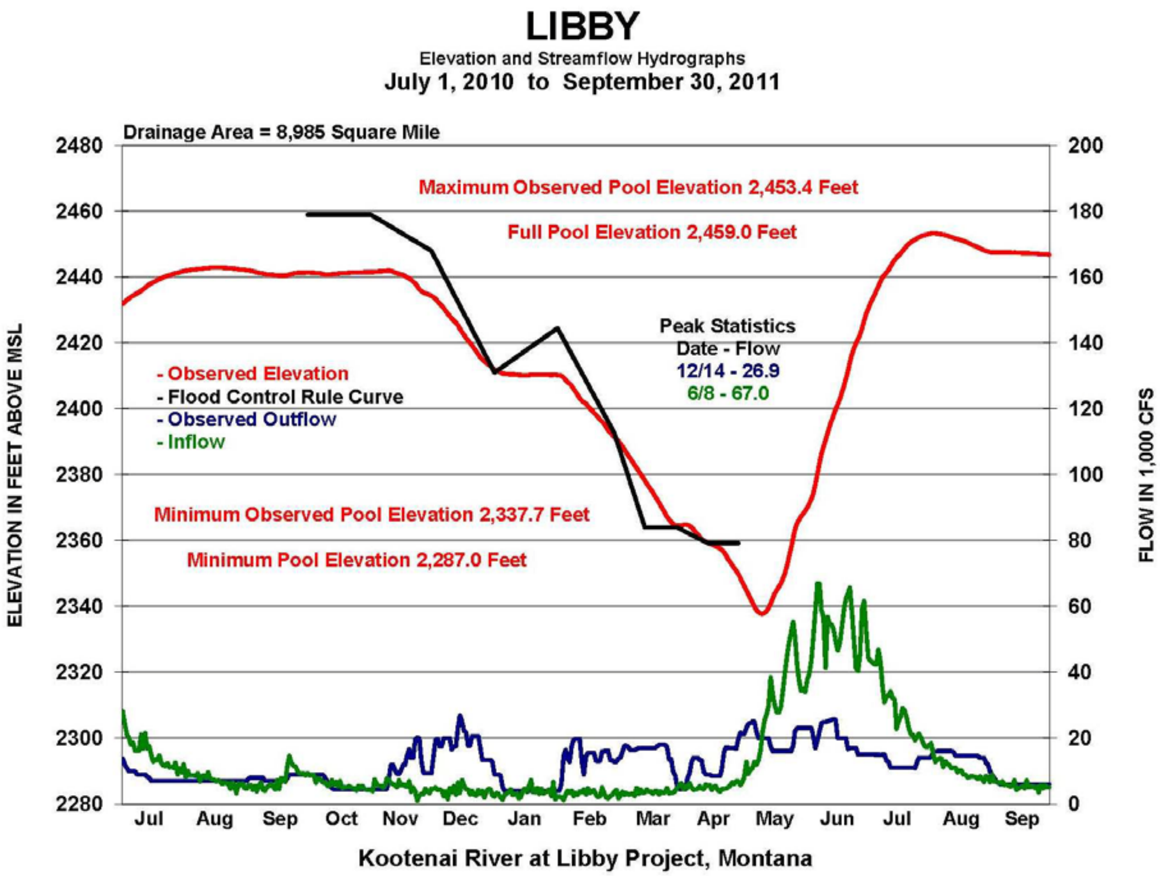


Chart 9: Regulation of Kootenay Lake

1 July 2010 – September 2011

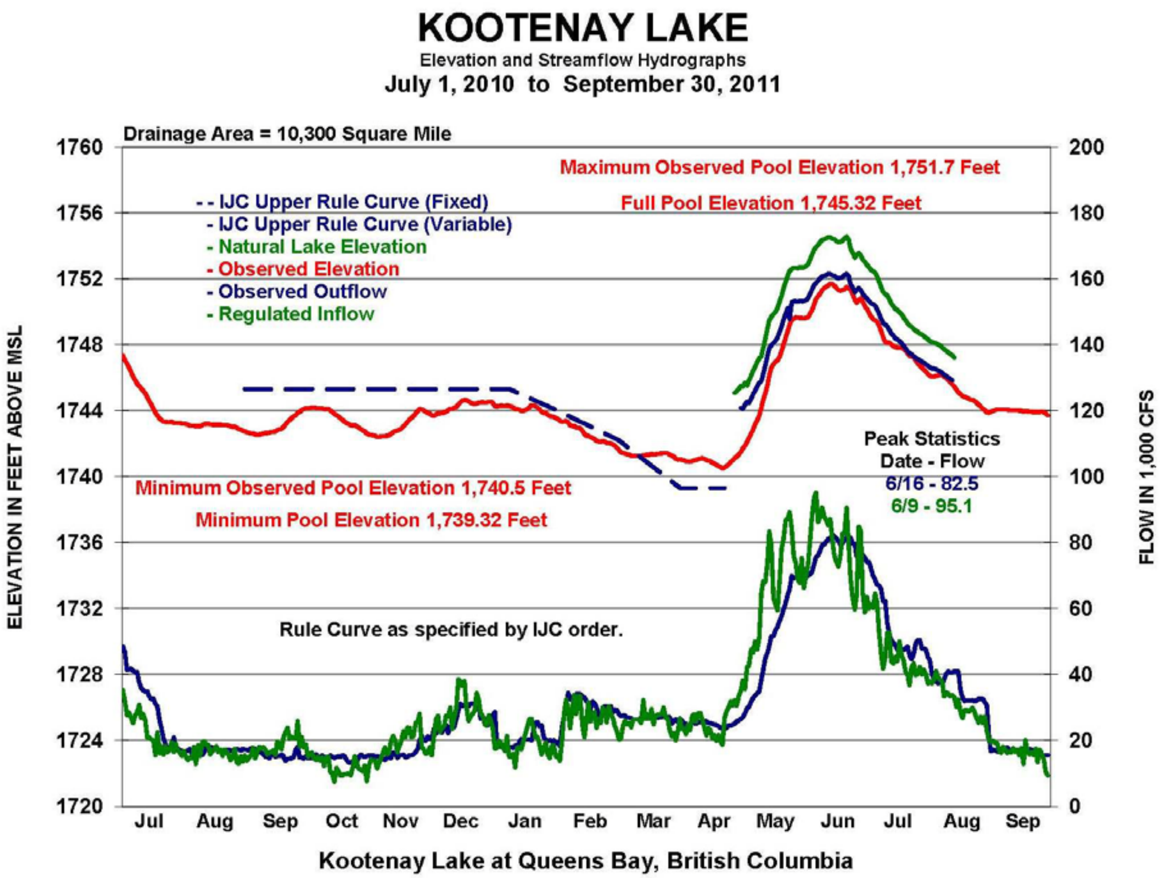


Chart 10: Columbia River at Birchbank

1 August 2010 – 30 September 2011

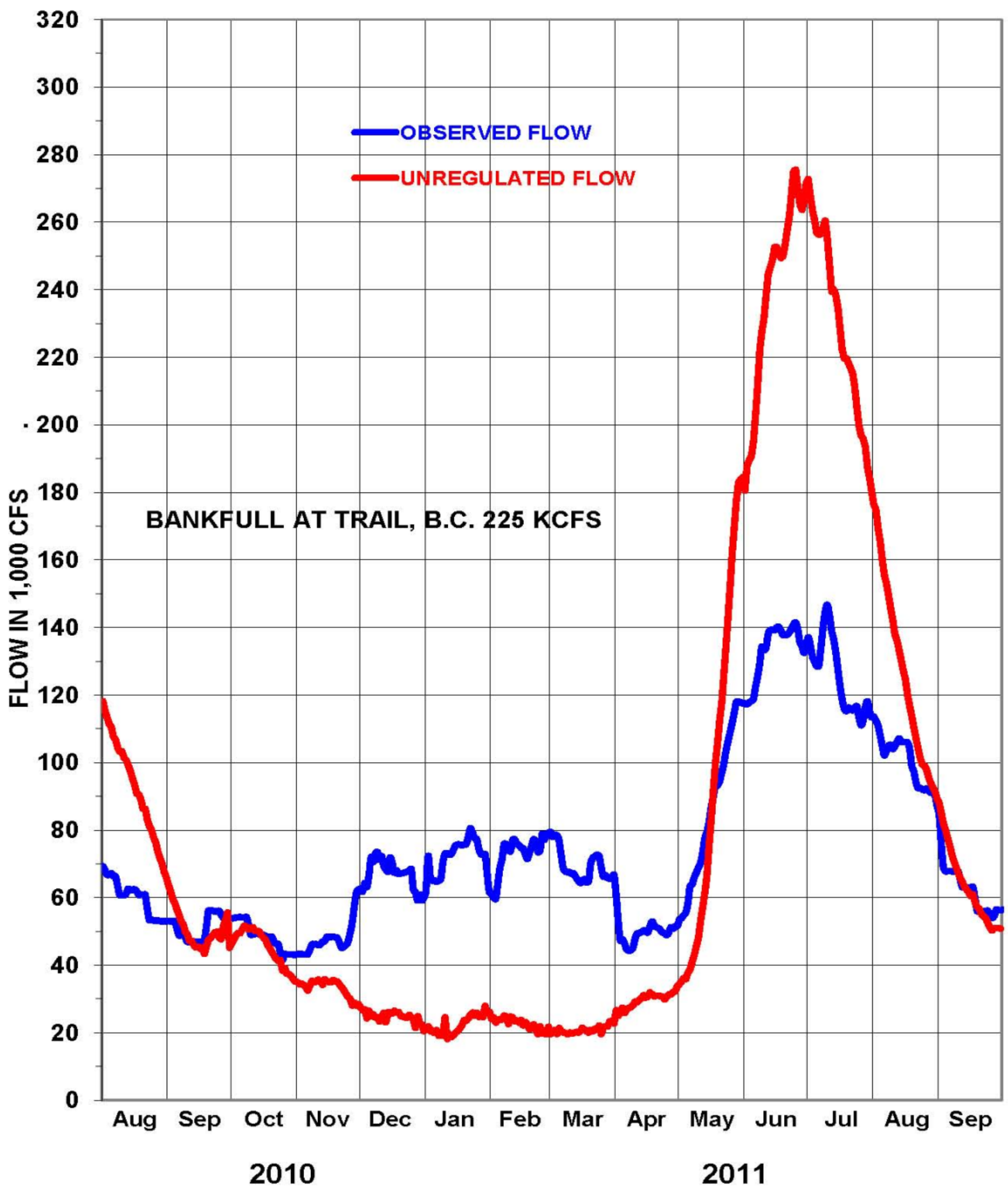


Chart 11: Regulation of Grand Coulee

1 July 2010 – 30 September 2011

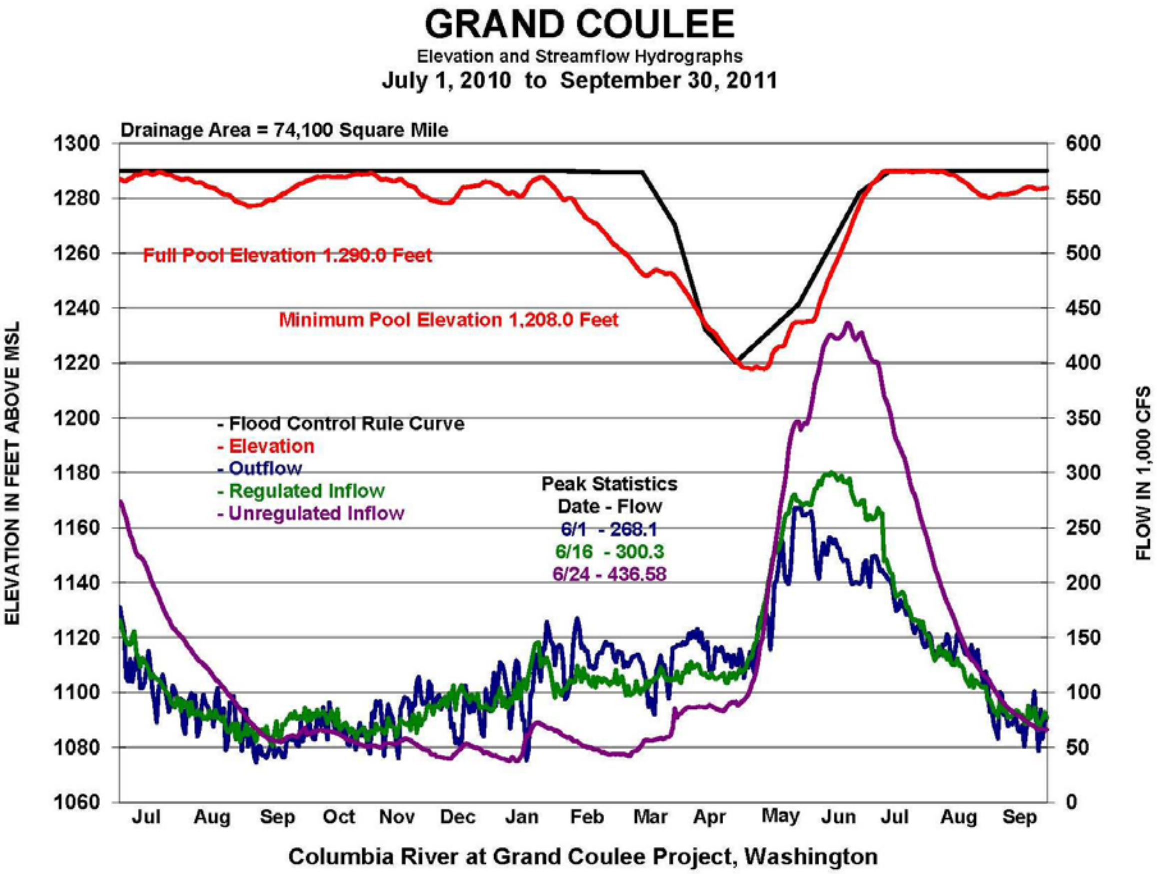


Chart 12: Columbia River at The Dalles

(Summary Hydrograph)

1 August 2010 – 30 September 2011

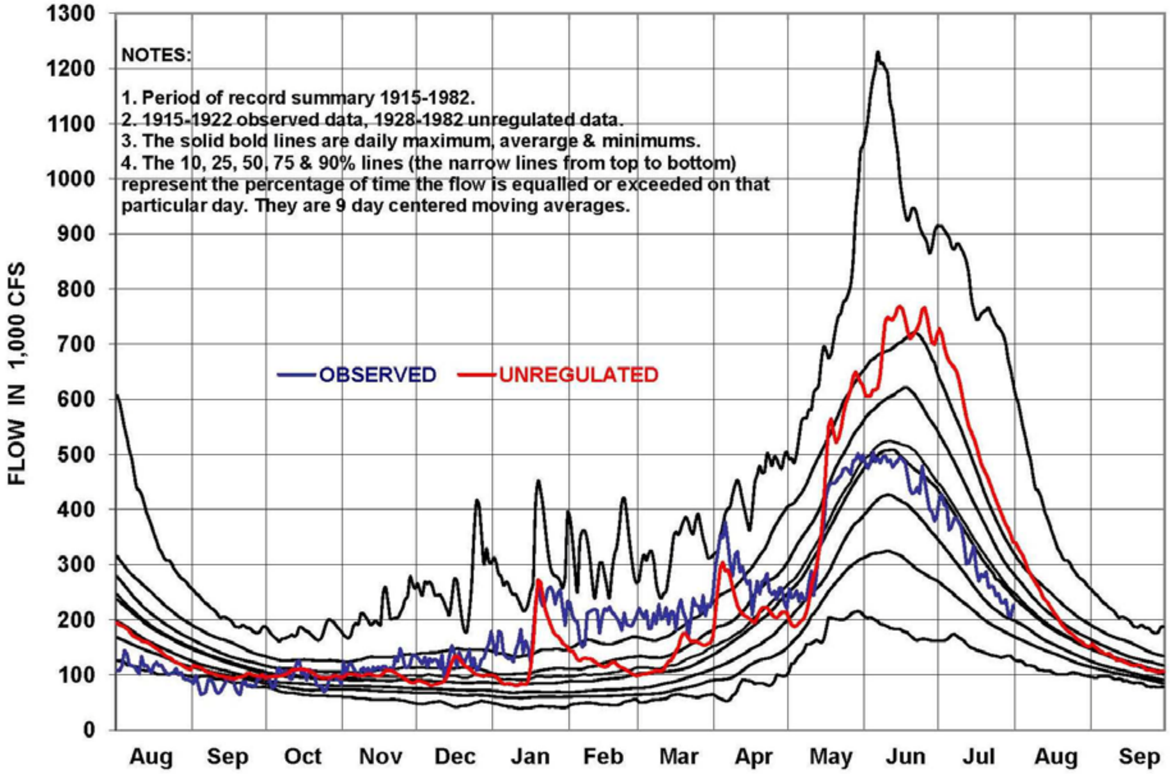


Chart 13: Columbia River at The Dalles

Re-Regulation Plot

1 April 2011 – 31 July 2011

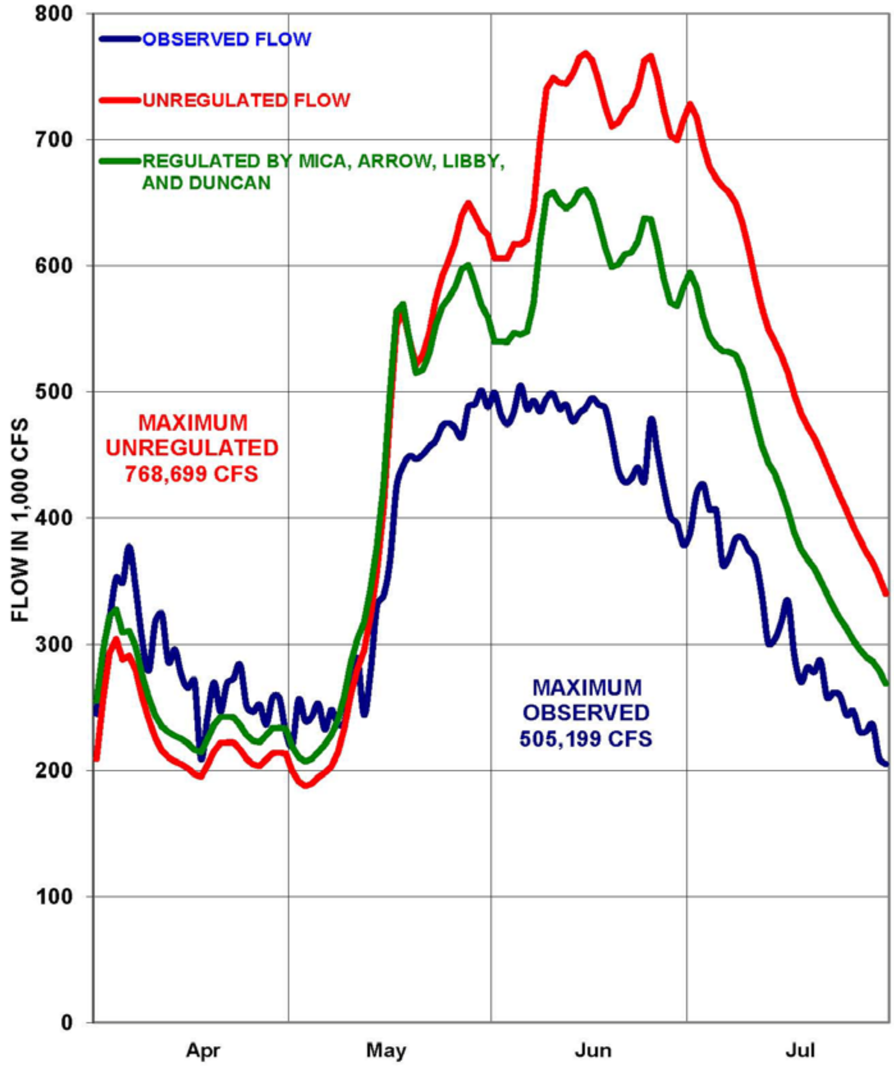


Chart 14: 2011 Relative Filling Arrow and Grand Coulee