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

1 October 2004 through
30 September 2005

ANNUAL REPORT OF
THE COLUMBIA RIVER TREATY
CANADIAN AND UNITED STATES ENTITIES

FOR THE PERIOD
1 OCTOBER 2004 – 30 SEPTEMBER 2005

DEDICATION

"The Entities dedicate this annual report to the memory of Ron Wilkerson, who served as a member of the Columbia River Treaty Permanent Engineering Board from 1988 until his untimely passing on 13 March 2005. Mr. Wilkerson's knowledge of Treaty history, insightful analysis, and collegial manner will be greatly missed by his Treaty Colleagues."

EXECUTIVE SUMMARY

General

The Canadian Treaty projects, Mica, Duncan, and Arrow were operated during the 1 August 2004 – 30 September 2005 reporting period according to the 2004-2005 and 2005-2006 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 2003 FCOP, the Libby Coordination Agreement (LCA) dated February 2000, U.S. requirements for power and guidelines set forth in the U.S. Fish and Wildlife Service (USFWS) and the U.S. National Marine Fisheries Service (NMFS) 2000 and 2004 Biological Opinions (BiOps). Canadian Entitlement power was delivered to Canada in accordance with the DOPs and Entitlement related agreements described below.

Entity Agreements

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

- Entity Letter Agreement on the Temporary Disposal of 414 MW of Canadian Entitlement Capacity and Associated Energy in the U.S., dated 23 June 2004, inadvertently omitted from the 2003-04 Annual Report.
- Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for the 2009-10 Operating Year, dated 6 December 2004.
- Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for 1 August 2005 through 31 July 2006, signed 24 June 2005.

Operating Committee Agreements

Agreements approved by the Operating Committee include:

- Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Nonpower Uses for the Period 1 December 2004 through 31 July 2005, signed 23 December 2004.

- Columbia River Treaty Operating Committee Agreement on the Operation of Arrow for the Period 29 January through 31 July 2005, signed 14 February 2005.

- Columbia River Treaty Operating Committee Agreement on Implementation Procedures for Flood Control Reallocation for the 2005-2006 Operating Year, signed 13 July 2005.

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System Operation

Under the 2004-2005 DOP, Canadian Treaty Storage was operated according to criteria from the 2005-2006 Assured Operating Plan (AOP) except for revisions to critical rule curves, system loads, and Arrow January outflows. The 2005-2006 AOP was selected instead of the 2004-2005 AOP because of mutual benefits. The 2005-2006 AOP included a flood control allocation of 6.29 cubic kilometers (km^3) (5.1 million acre-feet (Maf)) in Arrow and 2.57 km^3 (2.08 Maf) in Mica. B.C. Hydro requested a reallocation of the flood control space to operate to 5.03/4.44 km^3 (4.08/3.6 Maf) Mica/Arrow allocation. A process to implement the flood control reallocation was agreed to by the Committee on 28 June 2004 and 13 July 2005. The power operating criteria was modified for mutual benefits by raising the critical rule curves in August-October, lowering loads in August-September with a corresponding increase in load in December

Canadian Treaty storage began the operating year slightly below the DOP levels (by 125.3 hm^3 or 101.6 Kaf) determined in the Treaty Storage Regulation (TSR) study and was operated to forecasted TSR levels during August through December 2004 except for a small provisional draft authorized by the Libby Coordination Agreement. Substantial inadvertent draft occurred in September 2004 with Canadian storage ending the water year 909 hm^3 (737 Kaf) below the TSR. This was due to a large increase in forecasted September inflows from late August to early October, causing the end-of-September TSR level to raise by 1078 hm^3 (874 Kaf). In accordance with two Supplemental Operating Agreements, Canadian storage filled 1360.9 hm^3 (1103.3 Kaf) above the TSR in January 2005, remained above the TSR through June, and returned to the TSR in July, ending the Operating Year at 120.9 hm^3 (98.0 Kaf) below the TSR.

The 1 January 2005 water supply forecast (WSF) for the Columbia River at The Dalles for January through July was 105.6 cubic kilometers (km^3) (85.6 Maf), or

79.8 percent of the 1971-2000 average. The water supply forecast fell to a low of 87.2 km^3 (70.7 Maf) or 60.6% of normal in March, then ended up at 98.4 km^3 (79.8 Maf) or 78.8% of normal in June The seasonal precipitation for the water year was below average above The Dalles at 89 percent of average. The actual January through July volume at The Dalles was 100.35 km^3 (81.35 Maf), 76 percent of the 1971-2000 average. The peak unregulated flow at The Dalles in 2005 was estimated at 12,704 cubic meters per second (m^3/s) (448,672 cfs) on 22-May 2005 and a regulated peak flow of 8,184 m^3/s (286,500 cfs) on 18-May 2005.

The Columbia River was operated to meet chum needs below Bonneville Dam from 8 November 2004 through 5 May 2005. U.S. reservoirs were operated to target the 10 April flood control elevation per the NMFS 2004 BiOp for juvenile fish needs, but low inflow from January through March prevented this from happening. For 2005 Libby Dam released the volume of water requested by the U.S. Fish and Wildlife Service to meet downstream Kootenai River white sturgeon needs. The U.S. storage projects targeted full by 30 June 2005 per the Biological Opinion. Libby, Dworshak, Hungry Horse and Grand Coulee were all within 2.5 feet from full on June 30. Projects were then drafted to the NMFS 2004 BiOp draft limits for 31 August. Libby, Grand Coulee and Hungry Horse all reached their end of August BiOp elevations of 743.9 m (2439 feet), 389.79 m (1278 feet) and 1079.7 m (3540 feet). Dworshak reached the draft limit in September.

Canadian Entitlement

During the reporting period the U.S. Entity delivered the Canadian Entitlement to downstream power benefits from the operation of Mica, Duncan and Arrow reservoirs to the Canadian Entity, at existing points of interconnection on the Canada-U.S. border. The amount returned, not including transmission losses and scheduling adjustments, was 537.3 aMW at rates up to 1,176 MW during 1 August 2004 through 31 July 2005, and 535.1 aMW at rates up to 1,218 MW during 1 August 2005 through 30 September 2005.

During the course of the Operating Year, some curtailment of Canadian Entitlement occurred due to transmission constraints or emergencies on either the U.S. or Canadian side of the border. In all, 5 of the 8,760 hours (or 0.06% of the time) during this time experienced partial curtailment due to forced outages or diversion of power into constrained areas, for a total of 509 MWh out of 4,706,748 MWh scheduled to the border (0.01% of the total energy).

A portion of the Entitlement power was sold directly in the U.S. from 1 July 2004 through 31 October 2004, using the mutual agreement provisions of Section 5 of the 29 March 1999 “Disposals of the Canadian Entitlement within the U.S. for 1 April 1998 through 15 September 2024.” During these four months, 506,000 MWh were sold directly in the U.S. at a maximum agreed rate of 400 MW per hour. Of this amount, 140,800 MWh was delivered in the U.S. within the 2003-2004 Operating Year (in July 2004), and 365,000 MWh was delivered in the 2004-2005 Operating Year (in August, September, and October 2004).

Treaty Project Operation

At the beginning of the 2004-2005 operating year, 1 August 2004, actual Canadian storage was at 16.9 km^3 (13.7 Maf) or 88.5 percent full. Canadian storage ended the operating year on 31 July 2005, at 18.8 km^3 (15.2 Maf) or 98.3 percent full.

The Mica (Kinbasket) basin inflows were above normal during fall and winter 2004 due to rainfall runoff. With above normal inflows combined with low discharge requirements from Mica, the reservoir continued to refill from August through the first half of October to reach a maximum elevation of 748.01 m (2454.1 ft) on 19 October 2004. The reservoir drafted steadily, reaching 740.56 m (2429.7 feet) on 31 December 2004 and a minimum elevation of 724.91m (2378.3 feet) on 21 April 2005, 17.8 m (58.3 feet) above empty. The reservoir refilled to a maximum elevation of 750.57 m (2462.5 feet) on 8 August 2005, 3.81 m (12.5 feet) below full pool.

The Arrow reservoir reached its maximum of 436.24 m (1431.3 feet) on 12 August 2004, 3.9 m (12.7 feet) below full pool. Influenced by this low initial level, Arrow reservoir drafted to below normal level, reaching 426.84 m (1400.4 feet) by 31 December 2004. A minimum elevation of 426.08 m (1397.9 feet) was observed on 25 January 2005, 6.07 m (19.9 ft) above empty. Arrow reservoir refilled to a maximum elevation of 434.63 m (1425.9 feet) on 1 July 2005, 5.5 m (18.1 feet) below full pool. The operation of Arrow Reservoir was modified during the operating year under two Operating Committee Agreements. These agreements helped to enhance the success of whitefish and rainbow trout spawning and emergence downstream of the Arrow project in British Columbia and to provide additional non-power benefits in the United

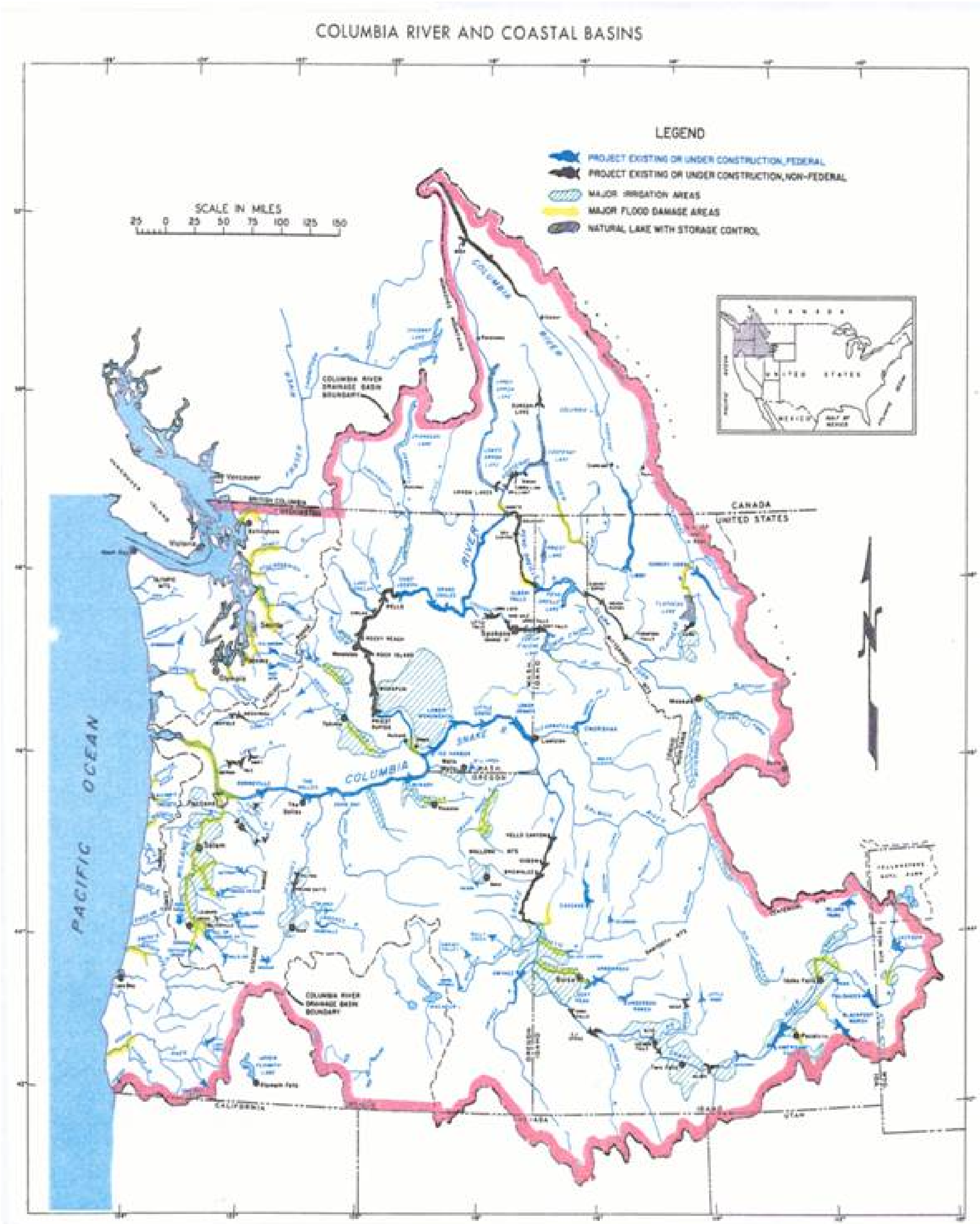
States (U.S.). Through coordinated efforts, B.C. Hydro was able to achieve the best (Tier 1 level) protection for whitefish for the 2004/05 operating year as defined by the Columbia Water Use Plan.

Duncan reservoir reached a maximum elevation of 576.45 m (1891.2 feet) on 17 August 2004, 0.20 m (0.8 feet) below full pool. From September 2003 through April 2004, Duncan discharge was used to supplement inflow into Kootenay Lake and to provide spawning and incubation flows for fish. The reservoir drafted to a minimum elevation of 547.56 m (1796.6 feet) on 21 April 2005, 0.69 m (2.4 feet) above empty. Reservoir discharge was reduced to the minimum of 3 m^3/s (100 cfs) on 25 May to initiate reservoir refill. The reservoir refilled to a maximum elevation of 576.48 m, (1891.4 feet) on 31 July 2005, 0.17 m (0.6 feet) below full pool.

Non-Treaty Storage

Since expiration of storage release provisions of the 1990 Non-Treaty Storage Agreement (NTSA) on 30 June 2004, there have been no operating agreements between the Bonneville Power Administration (BPA) and British Columbia Hydro and Power Authority (B.C. Hydro) relating to NTS. However, during the reporting period there was a small amount of water stored into NTSA accounts, in accordance with the refill provisions of the NTSA. No adverse affects were imposed on the operation of Treaty storage as a result of NTSA activities.

Columbia Basin Map



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Acronyms

AER	Actual Energy Regulation
aMW	Average Megawatts
AOP	Assured Operating Plan
B.C. Hydro	British Columbia Hydro and Power Authority
BiOp	Biological Opinion
BPA	Bonneville Power Administration
CEEA	Canadian Entitlement Exchange Agreement
CEPA	Canadian Entitlement Purchase Agreement
cfs	Cubic feet per second
CRC	Critical Rule Curve
CRT	Columbia River Treaty
CRTOC	Columbia River Treaty Operating Committee
CSPE	Columbia Storage Power Exchange
DDPB	Determinations of Downstream Power Benefits
DOP	Detailed Operating Plan
FCOP	Flood Control Operating Plans
hm^3	Cubic hectometers
ICF	Initial Controlled Flow
IJC	International Joint Commission
km^3	Cubic Kilometers
ksfd	Thousand second-foot-days (=kcfs x days)
LCA	Libby Coordination Agreement
LOP	Libby Operating Plan
m	Meter
m^3/s	Cubic meters per second
Maf	Million acre-feet
MW	Megawatt
NMFS	National Marine Fisheries Service
NOAA F	NOAA Fisheries, formerly NMFS
NTSA	Non-Treaty Storage Agreement
ORC	Operating Rule Curve
OY	Operating Year
PEB	Permanent Engineering Board
PEBCOM	PEB Engineering Committee
PNW	Pacific North West
STS	Summer Treaty Storage Agreement
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
WSF	Water Supply Forecast
VRC	Variable Rule Curve
WY	Water Year

I INTRODUCTION

This annual Columbia River Treaty (CRT) Entity Report provides information on the operation of Mica, Arrow, Duncan and Libby for the 2005 water year (WY), 1 October 2004 through 30 September 2005, with additional information for the Treaty Operating Year from 1 August 2004 through 31 July 2005. The power and flood control effects downstream in Canada and the U.S. are described. This report is the thirty-ninth of a series of annual reports covering the period since the ratification of the Columbia River Treaty (CRT) in September 1964.

Duncan, Arrow, and Mica reservoirs in Canada and Libby reservoir in the U.S. were constructed under the provisions of the CRT of January 1961. Treaty storage in Canada (Canadian storage) is operated for the purposes of flood control and increasing hydroelectric power generation in Canada and the U.S. In 1964, the Canadian and the U.S. governments each designated an Entity to formulate and carry out the operating arrangements necessary to implement the CRT. The Canadian Entity for these purposes is B.C. Hydro. The Canadian Entity for Entitlement Return is the government of the Province of British Columbia. The U.S. Entity is the Administrator/Chief Executive Officer of 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 is to provide 19.12 km^3 (15.5 Maf) of usable storage. This has been accomplished with 8.63 km^3 (7.0 Maf) in Mica, 8.78 km^3 (7.1 Maf) in Arrow and 1.73 km^3 (1.4 Maf) in Duncan.
2. For the purpose of computing downstream power benefits the U.S. base system hydroelectric facilities will be operated in a manner that makes the most effective use of the improved streamflow resulting from operation of the Canadian storage.
3. The U.S. and Canada are to share equally the downstream power benefits 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. 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.) for

each of the first four requests for this "on-call" storage. No requests have occurred 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.
10. In the Canadian Entitlement and Purchase Agreement (CEPA) of 13 August 1964, Canada sold its entitlement to downstream power benefits to the U.S. for 30 years beginning at Duncan on 1 April 1968, at Arrow on 1 April 1969, and at Mica on 1 April 1973. That sale has now expired, and all Canadian Entitlement has reverted to B.C. 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. are each to appoint Entities to implement Treaty provisions and are to jointly appoint a 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 23 February 2005 in Vancouver, British Columbia. The members of the two Entities at the end of the period of this report were:

UNITED STATES ENTITY	CANADIAN ENTITY
Mr. Stephen J. Wright, Chairman Administrator & Chief Executive Officer Bonneville Power Administration Department of Energy Portland, Oregon	Mr. Robert G. Elton, Chair President & Chief Executive Officer British Columbia Hydro and Power Authority Vancouver, British Columbia
Colonel Gregg F. Martin, Member Division Engineer Northwestern Division U.S. Army Corps of Engineers Portland, Oregon	

COL Martin replaced BG Grisoli as Member of the U.S. Entity on 22 July 2005.

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 hydroelectric operating plans and Flood Control Operating Plans (FCOPs) for the use of Canadian storage.

6. Prepare and implement Detailed Operating Plans (DOPs) that may produce results more advantageous to both countries than those that would arise from operation under Assured Operating Plans (AOPs).

Additionally, the CRT provides that the two governments, by an exchange of diplomatic notes, may empower or charge the Entities with any other matter coming within the scope of the CRT.

Entity Coordinators & Secretaries

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

The members are:

UNITED STATES ENTITY COORDINATORS
Stephen R. Oliver
Vice President, Generation Supply
Bonneville Power Administration
Portland, Oregon

Karen Durham-Aguilera
Director, Civil Works & Management
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY COORDINATOR
Kenneth R. Spafford
Technical Strategic Advisor, Generation
B.C. Hydro
Burnaby, British Columbia

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

CANADIAN ENTITY SECRETARY
Douglas A. Robinson
Integrated Operation and Risk Mgmt
Generation
B.C. Hydro
Burnaby, British Columbia

Mr. Oliver replaced Greg Delwiche as BPA U.S. Coordinator on 1 April 2005.

Columbia River Treaty Operating Committee

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

<u>UNITED STATES SECTION</u>	<u>CANADIAN SECTION</u>
Richard M. Pendergrass, BPA, Alt. Chair	Kelvin Ketchum, B.C. Hydro, Chair
James D. Barton, USACE, Alt. Chair	Dr. Thomas K. Siu, B.C. Hydro
Cynthia A. Henriksen, USACE	Gillian Kong, B.C. Hydro
John M. Hyde, BPA	Herbert Louie, B.C. Hydro

Mr. Barton replaced William Branch as Alternate Chair on 3 January 2005.
Ms. Kong replaced Allan Woo as Canadian Section Member on 23 September 2005.

The CRTOC met six times during the reporting period to exchange information, approve work plans, and discuss and agree on operating plans and issues. The meetings were held every other month alternating between Canada and the U.S. During the period covered by this report, the CRTOC:

- Coordinated the operation of the CRT storage in accordance with the current hydroelectric operating plans and FCOPs;
- Reviewed scheduled delivery of the Canadian Entitlement according to the CRT and related agreements;
- Completed studies and documents for the 2009-10 AOP/Determination of Downstream Power Benefits (DDPB);
- Completed the 1 August 2005 through 31 July 2006 DOP;
- Completed three supplemental operating agreements for Canadian storage.
- Implemented the Libby Coordination Agreement and monitored downstream Canadian power effects from Variable Q flood control operation at Libby;
- Updated 70-year flood control rule curves for AOP planning studies; and
- Briefed the Permanent Engineering Board and Engineering Committee on Entity activities.

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.

Columbia River Treaty Operating Committee at the 13 July 2005 Meeting

[Pictured from left to right: (front) Doug Robinson (BC Hydro, Canadian Entity Secretary), Kelvin Ketchum (BC Hydro, Canadian Chair), Tom Siu (B.C. Hydro, Member), Tony White, (BPA, U.S. Entity Secretary), (back) Cindy Henriksen (USACE, Member), Rick Pendergrass (BPA, U.S. Co-Chair), Allan Woo (B.C. Hydro, Member), James Barton (USACE, U.S. Co-Chair, John Hyde (BPA, Member), and Herbert Louie (B.C. Hydro, Member)]

Columbia River Treaty Hydrometeorological Committee

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

UNITED STATES SECTION	CANADIAN SECTION
Nancy L. Stephan, BPA Co-Chair	Stephanie Smith*, B.C. Hydro, Chair
Peter Brooks, USACE Co-Chair	Wuben Luo, B.C. Hydro, Member

*Stephanie Smith became the official B.C. Hydro Chair on 21 October 2004, replacing Eric Weiss.

The Hydrometeorological Committee (CRTHC) was established in September 1968 by the Entities and is responsible for planning and monitoring the operation of data facilities in accord with the Treaty. The CRTHC met twice in the 2004-2005 water year. The mid-year meeting took place on 24 February 2005 at B.C. Hydro's Headquarters in Vancouver, British Columbia and the fall meeting took place on 30 September 2005 at Bonneville Power Administration's Headquarters in Portland, Oregon.

The Columbia River Treaty Hydrometeorologic Committee 2003-2004 Annual Report was completed in May 2005 and distributed to the Columbia River Operating Committee at their meeting in Portland the same month.

Numerous issues arose throughout the year for the Committee varying from streamflow and water supply forecasting, to coordinating observed data, to addressing hydromet station changes.

With the completion of the 2000 Level Modified Flow study in 2003, the Committee dealt with how to apply, if at all, the information from this study to forecasting. Two areas where the Committee discussed the application of the Modified Flow data was in producing forecasts for AER/TSR purposes. The benefits of using a common data set are:

1. Consistency in methodology for computing a longer water supply forecast period from a shorter water supply forecast period.

2. Easier coordination of monthly streamflows for AER/TSR submittals.

One area discussed was the derivation of the January-July volume for Energy Content Curve (ECC – roughly equivalent to a CRT variable refill curve) computations from the volumes and periods produced by forecast equations. In particular, the Libby and Dworshak equations produce a volume forecast for April-August and April-July, respectively. In the past, the 30-year normal was used to convert this to a January-July volume. The CRTHC agreed, in order to align this computation with the monthly distribution factors for Libby and Dworshak to be implemented next year, to use the 71-year <u>mean</u> from the 2000 Level Modified Flow study to compute the January-July volumes. As new modified flow studies are developed and distribution factors updated, the recommendation is to also base the January-July computations on the new period of record.

Coordination of streamflows for the AER/TSR is occasionally a cumbersome and time-consuming process, primarily because the process involves coordination between three organizations, BPA, USACE, and BCH, and because different techniques are used for developing forecasts. In addition, the issue of how to blend an objective approach with a subjective or informed forecast has always been questionable. More specifically, it is not always clear how to blend knowledge of current conditions and the short-term (next 15 to 45 days) forecast with an objective method for the longer-range periods when little is known about the future weather or runoff shape. The USACE and BPA have been working on a methodology to limit the coordination to only the near-term streamflow forecast, with a common methodology to shape the longer-term forecast (based on the 71-year mean). While each organization is still left to develop its own short-term forecast and coordination still needs to occur for this period, once the short-term is agreed to, the remainder of the periods will use distribution factors based on the 71-year record mean from the 2000 Modified Flow study. This approach primarily applies to the water supply season.

A second issue which the Committee worked on throughout 2005 was the resolution of discrepancies in observed streamflow data for Canadian projects. For AER/TSR purposes, BPA submits the observed flows for Mica, Arrow, and Duncan. Traditionally, the observed numbers were taken from the NWRFC runoff processor which computes the observed unregulated flow at various points across the Basin, including the Canadian projects. Intermittently, it was noted that the NWRFC observed runoff for the Canadian projects was not the same as the observed values computed by BC Hydro. This issue was noted in 2004 and still continued to be a problem in 2005. However, steps were taken to move closer to resolving the issue in 2005. BCH began sending the NWRFC daily information on their projects in order to track flows throughout the month and avoid discrepancies at the end of the month. Even at the end of 2005, discrepancies continued to materialize but the Committee, with the help of the NWRFC, is isolating some of the causes and expects to resolve the issue in 2006.

Station issues are an ongoing item for the Committee. This year, three main areas of focus were:

- Marble Canyon (2C05) and Vermilion River No.3 (2C20) snow courses**:** Marble Canyon snow course was used in the 2004 new Libby forecast procedures. However this snow course was destroyed in the 2003 forest fire which completely changed the characteristics of the snow course. The CRTHC initiated studies to look at the impact of substituting the Marble Canyon with another snow course. The Vermilion River No.3 snow course which was inactive at the time was found to have very high correlation with the Marble Canyon snow course with correlation coefficient greater than 0.9. The impact of using Vermilion as an estimator for Marble Canyon in the new Libby equations was also found to be insignificant. The CRTHMC agreed to approach the BC MWLAP to re-activate Vermilion River No.3 and because of the prompt actions the Vermilion snow course was activated on time for the 2004/05 forecasting season.

- Mount Cook (1E02A) and Cook Forks (1E06) snow courses: Due to the observer retiring and the hazardous nature of reaching these snow courses, the BC MWLAP informed BCH of there intent to discontinue these two manual snow courses and replace with the Mount Cook (1E02P) and Cook Creek (1E14P) snow pillows. The CRTHC evaluated the potential closure and concluded that the impact to treaty operations is relatively small.

- Fernie precipitation site: Fernie climate station had not reported to Environment Canada since June 2004. Fernie precipitation data is used in the water supply forecasting procedures for Libby. BCH worked with Environment Canada get observations back again. Environment Canada was in the process of implementing a new online data entry system in April 2005. Data for Fernie began appearing again in April for use at the tail end of the water supply season.

Also of note, both the USACE and BCH were working on updating their water supply forecast procedures for Dworshak and all Canadian Treaty projects, respectively, in 2005. The CRTHC is currently reviewing these procedures.

BCH is taking a novel approach in developing its statistical water supply forecasting equations. The new approach looks at developing forecasting equations for individual monthly runoff volumes as opposed to the traditional approach oif a single equation for the seasonal volume at a given forecast date. The objective is to have a better handle on the forecasts of individual monthly volumes and associated uncertainties. BCH has completed the new procedures for all the treaty projects. The CRTHC is currently reviewing the new Mica procedures and will review others subsequently.

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 are presently:

UNITED STATES SECTION	CANADIAN SECTION
Stephen L. Stockton, Chair Washington, D.C.	Tom Wallace, Chair Ottawa, Ontario
Edward Sienkiewicz, Member-Nominee Newberg, Oregon	Tim Newton, Member Vancouver, British Columbia
Robert A. Pietrowsky, Alternate-Nominee Washington, D.C.	James Mattison, Alternate Victoria, British Columbia
George E. Bell, Alternate Portland, Oregon	David E. Burpee, Alternate & Secretary Ottawa, Ontario
Jerry W. Webb, Secretary Washington, D.C.	

Mr. Sienkiewicz, Member-Nominee, was nominated to replace Ron Wilkerson, following Mr. Wilkerson's death on 14 March 2005 and Mr. Sienkiewicz's appointment was made 8 August 2005. Dr. Pietrowsky, Alternate-Nominee, was nominated to replace Alternate- nominee Earl Eiker. Thomas Wallace's appointment as Chair of the Canadian Section was confirmed 22 March 2005.

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.
- ♦ 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, Operating Committee agreements, updates to hydrometeorological documents, and the annual Entity report to the Board for their review. The annual joint meeting of the PEB and the Entities was held on 23 February 2005 in Vancouver, British Columbia, where the Entities briefed the PEB on the preparation and implementation of operating plans, the delivery of the Canadian Entitlement, and other topics requested by the Board. The Entities also assisted the PEB and PEBCOM with their inspection trip through all four Treaty projects, completed from 30 August – 2 September 2005.

PEB Engineering Committee

The PEB has established a PEB Engineering Committee (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.	Roger S. McLaughlin, Chair Victoria, British Columbia
Michael S. Cowan, Member Lakewood, CO	Eve Jasmin, Member Toronto, Ontario
Kamau B. Sadiki, Member Washington, D.C.	Ivan Harvie, Member Calgary, Alberta
D. James Fodrea, Member Boise, ID	Dr. G. Bala Balachandran, Member Victoria, British Columbia

The PEBCOM met with the Operating Committee on 27 October 2004 in Portland, OR.

International Joint Commission

The International Joint Commission (IJC) was created under the Boundary Waters Treaty of 1909 between Canada and the U.S. Its principal functions are rendering decisions on the use of boundary waters, investigating important problems arising along the common frontier not necessarily connected with waterways, and making recommendations on any question referred to it by either government. If the Entities or the PEB cannot resolve a dispute concerning the CRT, that dispute may be referred to the IJC for resolution.

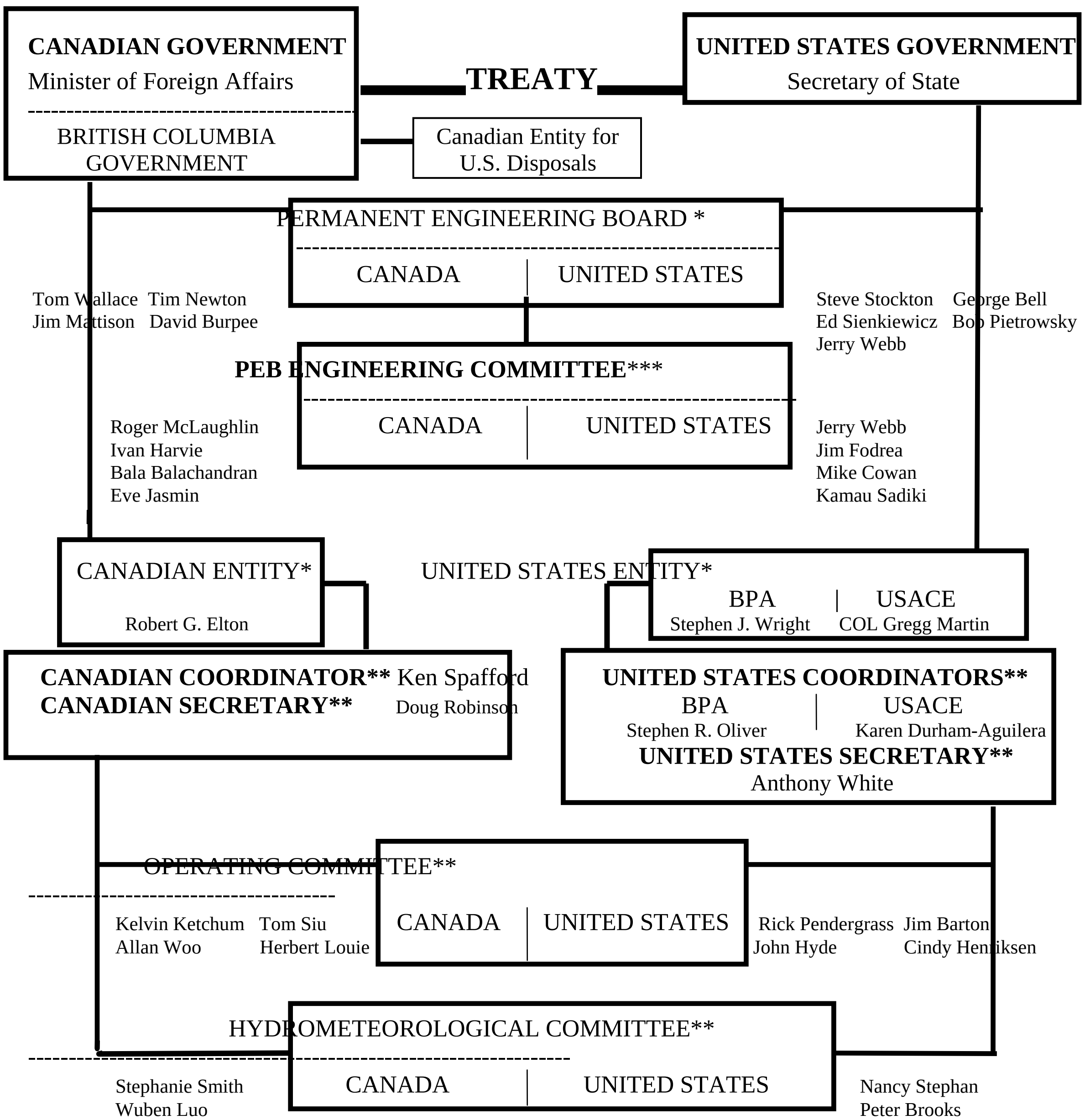
The IJC has appointed local Boards of Control to insure compliance with IJC orders and to keep the IJC informed. There are three such boards west of the continental divide. These are the International Kootenay Lake Board of Control, the International Columbia River Board of Control, and the International Osoyoos Lake Board of Control. The Entities and the 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 Dennis L. Schornack of Williamston, MI. The Canadian Section Chair is The Right Honorable Herb Gray of Ottawa, Canada. Canadian members are Mr. Robert Gourd of Montreal, QUE. and Mr. Jack P. Blaney of Vancouver, B.C. U.S. members are Ms. Irene B. Brooks of Seattle, WA and Mr. Allen I. Olson of Edina, MN.

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 Congressional staff, professional groups, the Northwest Power Planning Council staff, the Columbia Basin Trust staff, U.S. utilities, a State's Ecology Department, and several academic and civic groups. Additionally, an article was published in the September 2005 ***Hydro Review*** magazine outlining the Treaty's history and operating constraints, and describes the international team of organizations which make the Treaty work.

Columbia River Treaty Organization



* ESTABLISHED BY TREATY
** ESTABLISHED BY ENTITY
*** ESTABLISHED BY PEB

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 thereunder. Annex A of the CRT:

(1) Stipulates that the U.S. Entity will submit FCOPs;

(2) States that the Canadian Entity will operate in accordance with flood control storage diagrams or any variation which the Entities agree will not reduce the desired aim of the flood control plan; and

(3) Provides for the development of assured hydroelectric operating plans for Canadian storage for the sixth succeeding year of operation.

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

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

The planning and operation of CRT Storage as discussed on the following pages is for the operating year, 1 August 2004 through 31 July 2005. The operation of Canadian Storage was determined by the 2004-05 DOP and several supplemental operating agreements. The DOP required a semi-monthly Treaty Storage Regulation (TSR) study to determine end-of-month storage obligations prior to any supplemental operating agreements. The TSR included all operating criteria from, and was based on, the Step I Joint Optimum Power Hydroregulation Study from the 2005-2006 AOP, with agreed changes. Most of the hydrographs and reservoir charts in this report are for a 14-month period, August 2004 through September 2005.

Assured Operating Plans

During the reporting period, the Entities completed the 2009-10 AOP/DDPB using the load and resource streamline method developed for the prior AOP/DDPB and the procedures described in the 2003 Principles and Procedures document.

The 2009-10 AOP establishes 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, Upper Rule Curves (Flood Control), Variable Refill Curves and Operating Rule Curve Lower Limits, consistent with flood control requirements, as described in the 2003 Principles and Procedures document. They provide guidelines for draft and refill under a wide range of water conditions. The Flood Control Rule Curves conform to the 2003 FCOP, and are used to define maximum reservoir levels for the operation of Canadian storage. The 2009-10 AOP uses the 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 Treaty storage is made in conjunction with the AOP according to procedures defined in the CRT, Annexes, and Protocol. The total CRT downstream power benefits as a result of the operation of Canadian storage for operating years 2004-2005 and 2005-2006 were determined to be 1,074.6 MW and 1,070.3 MW average annual usable energy and 2,352.9 MW and 2,436.0 MW dependable capacity, respectively.

In conjunction with the 2009-10 AOP, the Entities completed the 2009-10 DDPB which showed a substantial increase in the downstream power benefits compared to the prior DDPB. The total CRT downstream power benefits as a result of the operation of Canadian storage for the 2009-10 operating year was determined to be 1,134.3 MW average annual usable energy and 2,704.5 MW dependable capacity.

Canadian Entitlement

The Canadian Entitlement to downstream power benefits was sold to the Canadian Storage Power Exchange (CSPE), a nonprofit consortium of 41 Northwest public and private utilities, in accordance with the Canadian Entitlement Purchase Agreement (CEPA) dated 13 August 1964. This sale was for a period of thirty years following the CRT-specified required completion date for each Canadian storage project. The purchase of the Canadian Entitlement under CEPA expired 31 March 1998 for Duncan, 31 March 1999 for Arrow, and 31 March 2003 for Mica. The CEPA purchases had fully expired prior to the start of the 2004-05 operating year, such that all of the Canadian Entitlement was deliverable back to Canada over the full operating year. For the period 1 August 2004 through 31 July 2005, this amount, before losses, was 537.3 aMW of energy, scheduled at rates up to 1,176 MW, and from 1 August 2005 through 30 September 2005, the amount, before losses, was 535.1 aMW of energy, scheduled at rates up to 1,218 MW. The Canadian Entitlement obligation was determined by the 2004-2005 and 2005-06 AOP/DDPB's.

During the course of the Operating Year, some curtailment of Canadian Entitlement occurred due to transmission constraints or emergencies on either the U.S. or Canadian side of the border. In all, 5 of the 8760 hours during this period, or 0.06% of the time, experienced full or partial curtailment due to forced outages or diversion of power into constrained areas for a total of 509 MWh out of 4,706,748 MWh scheduled to the border (0.01% of the total energy).

A portion of the Entitlement power was sold directly in the U.S. from 1 July 2004 through 31 October 2004, using the mutual agreement provisions of Section 5 of the 29 March 1999 "Disposals of the Canadian Entitlement within the U.S. for 1 April 1998 through 15 September 2024." During these four months, 506,000 MWh were sold directly in the U.S. at a maximum agreed rate of 400 MW per hour. Of this amount, 140,800 MWh was delivered in the U.S. within the 2003-2004 Operating Year (in July 2004), and 365,000 MWh was delivered in the 2004-2005 Operating Year (in August, September, and October 2004).

Detailed Operating Plans

During the period covered by this report, the Operating Committee used the 1 August 2004 through 31 July 2005 "Detailed Operating Plan for Columbia River Treaty Storage", dated June 2004 and the 1 August 2005 through 31 July 2006 DOP, dated

June 2005, to guide storage operations. These DOPs established criteria for determining the ORCs, proportional draft points, and other operating data for use in actual operations. The 2004-2005 DOP was based on the 2005-2006 AOP instead of the 2004-2005 AOP because of mutually beneficial changes in operating criteria. The respective AOP loads and resources, rule curves, and other operating criteria with agreed changes for both Canadian and U.S. projects, were used to develop the Treaty Storage Regulation (TSR) studies for implementation of operations. The changes were mainly updates to flood control rule curves, hydro-independent data, the operation of the Brownlee project, and raising the critical rule curves in August-October, lowering loads in August-September with a balancing increase in December, and limiting January Arrow outflows to a maximum of 1,841 m^3/s (65 kcfs). The 2005-2006 DOP was also based on the 2005-2006 AOP with changes similar to the 2004-2005 DOP except for the revisions to critical rule curves, system loads, and Arrow January outflows.

The 2005-2006 AOP included a flood control allocation of 6.29 km^3/m (5.1 Maf) in Arrow and 2.57 km^3/m (2.08 Maf) in Mica. B.C. Hydro requested a reallocation of the flood control space to operate to a 5.03/4.44 km^3/m (4.08/3.6 Maf) Mica/Arrow allocation. A process to implement the flood control reallocation was agreed to by the Committee on 28 June 2004 and 13 July 2005.

The TSR studies were updated twice monthly throughout the operating year, and together with supplemental operating agreements, defined the end-of-month draft rights for Canadian storage. The Variable Rule Curves (VRCs) and flood control requirements subsequent to 1 January 2005 were determined on the basis of seasonal volume runoff forecasts during actual operation. The VRC calculations for Canadian reservoirs and Libby for the 2004-2005 operating year are shown in Tables 2 through 5. The tabular calculation in Table 5 for Libby's VRCs were used in the TSR study only and are not used in real time operations.

The Operating Committee directed the regulation of the Canadian storage, on a weekly basis throughout the year, in accordance with the applicable DOPs and supplemental operating agreements made there under.

Libby Coordination Agreement

During the period covered by this report, the Libby Coordination Agreement (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. The Libby Operating Plan (LOP) was not updated during the reporting period.

Entity Agreements

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

Date Agreement Signed by Entities	Description
23 June 2004	Entity Letter Agreement for Temporary Disposal of 414 MW of Canadian Entitlement Capacity and Associated Energy in the United States.
25 June 2004	Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for 1 August 2004 through 31 July 2005.
6 December 2004	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for the 2009-10 Operating Year

Operating Committee Agreements

During the period covered by this report, the Operating Committee approved three joint U.S. - Canadian agreements:

Date Agreement Signed by Committee	Description	Authority
23 December 2004	Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Nonpower Uses for the Period 1 December 2004 through 31 July 2005	Detailed Operating Plan, 1 August 2004 through 31 July 2005, approved June 2004 and dated 24 June 2004
14 February 2005	Columbia River Treaty Operating Committee Agreement on the Operation of Arrow for the Period 29 January through 31 July 2005	Detailed Operating Plan, 1 August 2004 through 31 July 2005, approved June 2004 and dated 24 June 2004
13 July 2005	Columbia River Treaty Operating Committee Agreement on Implementation Procedures for Flood Control Reallocation for the 2005-2006 Operating Year	Detailed Operating Plan, 1 August 2005 through 31 July 2006, approved 24 June 2005 and dated June 2005

Long Term Non-Treaty Storage Contract

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 Operating Committee, in accordance with that agreement, monitored the storage operations made under this agreement throughout the operating year to insure that they did not adversely impact operation of CRT storage. The Entity agreement dated 28 June 2002, gave approval for B.C. Hydro and BPA to extend the expiration date of the contract by one year, from 30 June 2003 to 30 June 2004, which was done. Two Mid-Columbia parties, Eugene Water and Electric Board and Tacoma Utilities, elected to extend their NTSA Agreement with BPA for the same one-year period.

No further extension of the contract was completed, however, and as per contract terms, release rights under the Non-Treaty Storage Agreement terminated effective 30 June 2004. While the parties anticipate negotiating a replacement coordination agreement to make use of the non-Treaty storage space available in the Mica and Arrow reservoirs, low NTSA storage levels, low runoff conditions and high market prices over the last few years have provided little economic incentive to expedite these negotiations. In the absence of a new agreement, the extended Provisions of the 1990 Agreement require that active Non-Treaty Storage Space in Mica be refilled prior to 30 June 2011.

IV WEATHER AND STREAMFLOW

Weather

A warm and dry June and July 2004 transitioned into a wetter and warmer than normal August due to low pressure troughs at the beginning and end of the month, and intermediate high pressure ridging. Wet conditions continued in September, raising hopes of a good start to the water year. An active jet stream within a broad area of low pressure supplied the region with 165 percent of normal precipitation at Columbia above Coulee, and 148 percent of normal at Columbia above The Dalles, and 124 percent of normal in the Snake Basin, above Ice Harbor, for September. This was on the heels of 195 percent, 204 percent, and 192 percent of normal precipitation in the usually dry month of August. August saw a greater temperature swing, from -0.8 °C to 4.1 °C (-1.4 °F to +7.3 °F), and September came in a little narrower, -1.6°C to 1°C (-2.8 °F to 1.8 °F). The active early autumn weather settled down some as October arrived.

A ridge of high pressure started out the month, and carried on toward mid month. In the middle of October, this regime resulted in record high temperatures at Pendleton, 30 °C (86 °F), and at Portland, 27.2 °C (81 °F), and the month’s average temperature departed +0.7 °C (+1.2 °F). Then storms arrived via a jet stream incoming from the northwest. With a much cooler Gulf of Alaska airstream, temperature departures dropped off, and precipitation rose. Precipitation accumulated to 110 percent of normal at Columbia above Coulee, 123 percent of normal at Columbia above The Dalles, and 163 percent of normal at the Snake River above Ice Harbor. The October precipitation boosted streamflows, but a change in course was due to occur in November, ultimately dropping these during the month. In November, the region saw a split develop in the jet stream. As a result, flows trailed off, and precipitation ended up at 72 percent of normal at Columbia above Coulee, 60 percent of normal at Columbia above The Dalles, and 50 percent of normal at the Snake River above Ice Harbor. Were it not for a tropically-fed frontal system about mid month, the precipitation percentages would have been lower. Temperatures were cooler than normal over Oregon and Idaho, and warmer than normal elsewhere during November, a regime typical of a split-flow pattern. Overall, regional temperatures departed +0.6 °C (+1.0 °F) from normal, with absolutes from -1.7 ° C to 3.8 ° C (-2.1 °F to +6.9 °F). The split in the flow continued into December.

Again, this time in the final month of 2004, the region received most of its precipitation from a frontal system that tapped tropical moisture. Overall, the split flow carried above normal precipitation into California and far north along the northern B.C. coast and into the Alaskan Peninsula. Only parts of southern Oregon and far south Idaho caught slightly above normal precipitation. As a result of this split, precipitation was 76 percent of normal at Columbia above Coulee, 75 percent of normal at Columbia above The Dalles, and 80 percent of normal at the Snake River above Ice Harbor. For the second month in a row, the tropical moisture tap offset the threat of abysmal precipitation totals, and also contributed to a large streamflow increase from the 5th through 15th. December was a very mild month, as well, so only higher elevation snow managed to sufficiently accumulate. On the cool side, departures bottomed out at +1°C (+1.8 °F) and topped out at 5.6 °C (+10.1 °F), bringing the average departure to 2.8 °C (+5.1 °F). Some much cooler weather ushered in 2005, as the split flow from November and December pulled a bit to the west, allowing Arctic air to briefly move into the Basin, during January, via a northerly flow.

Even with precipitation in this kind of a pattern, amounts are generally light. And that was the case until about mid month as the southern part of the split in the jet stream once again tapped tropical moisture. This was courtesy of a large Gulf of Alaska low pressure area that really managed to arc the northern part of the split flow in over the Basin. Combined with the delivered precipitation from the tropics, this warming airmass came with a very deep southerly flow. This sent temperatures to record levels in January. Portland, Seattle, Olympia, Bellingham, Quillayute, Medford, Hillsboro, and Corvallis all broke their record high temperatures, with most broken between the 12th and 21st. Basin-wide temperatures departed swung wide due to the extremes of the month: On the cold end, they met -2.2 °C (-4.0 °F), and at the other extreme, +3.3 °C (+5.9 °F). January averaged +0.7°C (+1.2 °F) from normal. January precipitation was 100 percent of normal at Columbia above Coulee, 78 percent of normal at Columbia above The Dalles, and 81 percent of normal at the Snake River above Ice Harbor. Streamflows responded with the precipitation and warming, with a large increase that peaked at the end of the month. So, a month of contrasts to open a new year gave way to a month of one-way extreme as February's weather pattern reverted to a more definitive split flow, and consequently much below normal precipitation.

The Basin realized most of its meager February amounts early on, and the accumulation resulted in 23 percent of normal at Columbia above Coulee, 30 percent of normal at Columbia above The Dalles, and 73 percent of normal at the Snake River above Ice Harbor. February 2005 regional temperatures continued above normal, averaging +0.6 °C (+1.0 °F) from normal, and containing a range from -1.9 °C to +3.4 °C (-3.5 °F to +6.2 °F). In February, we saw both high and low temperature records broken: Olympia reached 18.3 °C (65 °F) and Astoria 20°C (68 °F), while Olympia broke a low temperature record three times during the month. So, the split flow pattern had both temperature and precipitation repercussions, and these held into March. But, by the middle of that month, the weather pattern began to change, perhaps as a consequence of a large change in the pressure pattern across the Equatorial Pacific. As March wore on, precipitation increased due to a series of cold fronts crossed the region, with a notably strong weather system late in the month. Cumulatively, this resulted in a sharp rise in streamflows from the 27th onward, singularly from 115 percent of normal precipitation at Columbia above Coulee, 109 percent of normal at Columbia above The Dalles, and 108 percent of normal at the Snake River above Ice Harbor. With this increase in precipitation, we saw several daily records, including 3.0 cm (1.19") at Portland, 3.8 cm (1.51") at Seattle, 1.1 cm (0.45") at Lewiston, and 2.2 cm (0.88") at Spokane. Many high temperature records were broken, and these occurred early in the month, within the split flow pattern. Some of these included 19.4 °C (67 °F) at Seattle, 24.4 °C (76 °F) at Portland and Redmond, 19.4 °C (67 °F) at Astoria and Olympia, and 26.7°C (80 °F) at Medford. Ironically, Olympia broke its low temperature record on the same day that it broke its high: the capital city started out at -3.9 °C (25 °F) that day! Overall, March was warmer than normal, departing +1.4 °C (+2.5 °F), with mean departures ranging from -1.7 °C to +4.8 °C (-3.1 °F to +8.3 °F). March really began the back and forth temperature swing that would continue through most of the Summer! March's wet pattern continued into the first part of April.

More storms brought above normal precipitation region wide for the first half of the month, but a return of the split flow regime dried out northern areas, yet kept southern districts wetter than normal. As a result, April precipitation was 86 percent of normal at Columbia above Coulee, 101 percent of normal at Columbia above The Dalles, and 119 percent of normal at the Snake River above Ice Harbor. More precipitation records were broken in April. Astoria broke a daily record by measuring 4.9 cm (1.92”), and another with 2.2 cm (0.86”). Yakima, Redmond, and Pocatello broke daily records, accumulating 1.1-2.3 cm (0.45-0.90”). With temperature swings from -1.4 °C to + 2.8 °C (-2.5 °F to +5.1 °F), April averaged very close to normal, departing 0.4 °C (+0.8 °F). The largely wetter-than-normal Spring continued in May, even with a split in the jet stream. The northern arm of the split forced precipitation into the Canadian Upper Columbia and into the Canadian and U.S. Kootenay, while the southern part of the split brought above normal amounts across the southern tier basins. Above normal precipitation continued through May, as the Columbia above Coulee measured 109 percent of normal, the Columbia above The Dalles at 150 percent of normal, and the Snake River above Ice Harbor totaled a robust 194 percent of normal. Streamflows continued a steep rise, from April, and peaked late in May. Several more daily precipitation records were broken in May, including, Portland, at 1.5 cm (0.59”) and Spokane at 2.2 cm (0.88”). May was warmer than normal, due mainly to milder than normal overnight temperatures, and high pressure ridging toward the latter part of the month. The month averaged +1 °C (+1.8 °F), with mean temperatures departures ranging from -0.7 °C to +4.0 °C (-1.2 to +7.2 °F). This warmth caused Medford to break a daily record at 35 °C (95 °F), as did Portland, with Seattle at 31.7 °C (89 °F). Warm temperatures turned much cooler as June arrived, but it remained wet due to a little more consolidation of the upper air flow.

Relative to what we expect for June, many regions of the Basin notched much above normal precipitation. A series of chilly storms, out of the ordinary for June, kept flows alive for the month, with only a small recession. Precipitation totaled 178 percent of normal at Columbia above Coulee, 141 percent of normal at Columbia above The Dalles, and 133 percent of normal at the Snake River above Ice Harbor. Again, several daily precipitation records fell: at Portland, Sand Point (Idaho), Idaho Falls and Kalispell. Western Montana was particularly hard hit with this weather pattern, thanks to a cool northwesterly flow, a by-product of the consolidation of the upper air flow. Regional temperatures departed -0.7 °C (-1.2 °F), and skewed chilly even on the range: -2.4 °C to only +0.9 °C (-4.4 °F to only +1.7 °F). Cooler than normal weather continued into July, as more cold fronts traversed the region. By mid to late in the month, higher pressure covered the U.S. part of the Basin, pretty much on time for the start of the Pacific Northwest’s Summer. As such, the storm track ended up in Canada. July precipitation ended at 72 percent of normal at Columbia above Coulee, 65 percent of normal at Columbia above The Dalles, and 40 percent of normal at the Snake River above Ice Harbor. July ended warmer than normal, with daily temperature records set at Burns and Boise, at 37.8 °C and 40.6 °C (100 °F and 105 °F), respectively. The warm weather carried over into August, as an upper air high pressure area dominated for most of the month.

With the high in place, the storm track remained across the Canadian Upper Columbia, with even that area receiving below normal precipitation amounts. As such, and collectively, precipitation totaled 63 percent of normal at Columbia above Coulee, 58 percent of normal at Columbia above The Dalles, and 62 percent of normal at the Snake River above Ice Harbor. August's high pressure system largely sat over the western part of the Basin, and this allowed a cooler temperature pattern to maintain over eastern districts, like the Kootenay and Upper Snake. Late in August, a low pressure system managed to drop into the Basin from the northwest, and the resultant unstable airmass produced numerous, and occasionally heavy, regional showers. For example, Troutdale set a 24-hour precipitation record of 3.9 cm (1.55") on the 29th of the month. Although most of the Basin saw above normal temperatures for the month, areas on the eastern edge of the upper high were cooler than normal. Overall, regional temperatures departed +0.8 °C (+1.4 ° F). Cooler weather was on the way, though, as the Basin entered September.

And, although September managed to start quite mild, a springboard from August and thanks to a westerly flow and high pressure aloft, temperatures turned cool and stayed cool from about the 5th through the 25th. As such, the U.S. part of the Basin registered as the 53rd coolest September on record, based on the period, 1895-2004. Combined temperature departures of Spokane, Portland and Seattle came in at -0.8 °C (-1.5 °F). Because of the orientation of the high pressure, precipitation for most of the month was limited to the Canadian Upper Columbia, and over the far southeastern Idaho Upper Snake. The Canadian precipitation totaled slightly below to near normal until the final two days of the month when the weather pattern transitioned so that a potent weather system delivered abundant precipitation to many districts. To the 30th of the month, precipitation averaged 223 percent of normal at Columbia above Coulee, 153 percent of normal at Columbia above The Dalles, and 75 percent of normal at the Snake River above Ice Harbor. Suddenly, then, what could have one of the driest Septembers on record for many U.S. locales, ended up being slightly below to just at normal! In spite of this, and based on the long 1895-2004 period of record, this month ended as being the 23rd driest month on record.

Streamflow

Monthly and Seasonal reservoir inflow at many key locations throughout the Columbia Basin are shown in Chart 4. The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 July 2004 through 31 July 2005 are shown on Charts 5-7. Libby hydrographs are shown in Chart 8. Observed flow as well as computed unregulated flow hydrographs for the same 13-month period for Kootenay Lake, Columbia River at Birchbank, Grand Coulee, and The Dalles are shown on Charts 9-12, respectively. Observed and unregulated flow hydrographs at The Dalles during the April-July 2005 period, including a plot of flows occurring if regulated only by the four Treaty reservoirs, is given in Chart 13. Composite operating year unregulated streamflows in the basin above The Dalles were below normal, but were approximately 12-percent above last year's below average streamflows. Inflows during spring runoff were highest in May at 81-percent of average. The August 2004 through July 2005 runoff for The Dalles was 140.3 km^3 (113.7 Maf), 82 percent of the 1971-2000 average. The peak-unregulated discharge for the Columbia River at The Dalles was 12,705 m^3/s (448,700 cfs) and occurred on 22 May 2005. The 2004-2005 average monthly unregulated streamflows and their percentage of the 1971-2000 average monthly flows are shown in the following tables (metric and English) for the Columbia River at Grand Coulee and The Dalles. These flows have been adjusted to exclude the effects of regulation provided by storage reservoirs.

Columbia River Flow in Metric Units

	Columbia River at Grand Coulee in m^3/s		Columbia River at The Dalles in m^3/s	
Time Period	Natural Flow	Percentage of Average	Natural Flow	Percentage of Average
Aug-04	2671	90	3408	88
Sep-04	2417	137	3383	128
Oct-04	1674	132	2718	116
Nov-04	1509	109	2574	96
Dec-04	1631	134	3023	108
Jan-05	1747	147	3279	113
Feb-05	1549	115	2852	83
Mar-05	1546	88	2786	63
Apr-05	3032	87	5028	75
May-05	6380	85	9951	81
Jun-05	6897	79	8946	67
Jul-05	4368	80	5349	73
Period Average	2952	107	4441	91

Columbia River Flow in English Units

	Columbia River Grand Coulee in cfs		Columbia River at The Dalles in cfs	
Time Period	Natural Flow	Percentage of Average	Natural Flow	Percentage of Average
Aug-04	94312	90	120366	88
Sep-04	85339	137	119471	128
Oct-04	59118	132	95987	116
Nov-04	53274	109	90901	96
Dec-04	57605	134	106753	108
Jan-05	61703	147	115796	113
Feb-05	54702	115	100725	83
Mar-05	54596	88	98378	63
Apr-05	107085	87	177551	75
May-05	225297	85	351420	81
Jun-05	243580	79	315911	67
Jul-05	154259	80	188900	73
Period Average	104239	107	156847	91

Seasonal Runoff Forecasts and Volumes

April-August 2005 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 KAF	Percentage of 1971-2000 Average
Libby Reservoir Inflow	6.9	5563	89
Duncan Reservoir Inflow	2.3	1835	90
Mica Reservoir Inflow	13.0	10572	93
Arrow Reservoir Inflow	25.0	20300	89
Columbia River at Birchbank	44.0	35678	88
Grand Coulee Reservoir Inflow	60.2	48783	81
Snake River at Lower Granite	17.8	14393	63

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2005 for a large number of locations in the Columbia River Basin and updated each month 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 and Libby 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 1 April 2005 forecast of January through July runoff for the Columbia River above The Dalles was 91.0 km^3 (73.8 Maf) and the actual observed runoff was 100.3 km^3 (81.3 Maf).

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

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

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

V RESERVOIR OPERATION

General

The 2004-2005 operating year began with Canadian storage at 89.1 per cent of full. Libby reservoir (Lake Koocanusa) was not full on 1 August 2004 as the dam was releasing water to meet the objectives for flow augmentation for listed salmon species in the U.S.

The September and October project inflows are normally the lowest of the year, but due to rainfall there were high inflows in September and October (192% and 123% of normal at Libby and 105% and 130% at Mica) which caused Canadian reservoirs and Libby reservoir to fill slightly. The January water supply forecast at the Canadian basins was slightly below average and dropped to around 90% in the spring. Canadian storage ended the year at 99.0 per cent full.

Two CRTOC operating agreements enhanced fishery operations at Arrow. Libby Dam operated to meet the needs of both U.S. Fish and Wildlife Service 2000 Biological Opinion, and the NOAA Fisheries 2004 Biological Opinion. Libby operated in accordance with Appendix B (the Libby Operating Plan) of the Libby Coordination Agreement (LCA).

Canadian Treaty Storage Operation

At the beginning of the 2004-2005 operating year on 31 July 2004, actual Canadian Treaty storage (Canadian storage) was at 17.0 km^3 (13.8 Maf) or 89.1 percent full. Canadian storage gradually refilled to 18.1 km^3 (14.7 Maf) or 95 percent full in September 2004 before drafting to a minimum of 4.8 km^3 (3.9 Maf) on 31 March 2005. Substantial inadvertent draft occurred in September 2004 with Canadian storage ending the water year 909 hm^3 (737 Kaf) below the TSR. This was an inadvertent draft below TSR that resulted from large changes in the TSR through the month. The TSR change from the late August TSR that set up operations as we entered the month until the final TSR for September which was run in early October, resulted in a composite Treaty content increase of 2,148 hm^3 (878 ksfd). Unlike the previous year, Canadian storage refilled to near full by the end of the operating year, reaching 18.9 km^3 (15.3 Maf) or 99.0 percent full on 31 July 2005.

As specified in the Detailed Operating Plan (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 Treaty Storage Regulation (TSR) plus supplemental operating agreements so long as this variance does not impact the ability of the Canadian system to deliver the sum of CRT outflows from Arrow and Duncan reservoirs. Variances from the DOP storage operation are accumulated in respective Flex accounts. An overrun in an account occurs when actual project releases are greater (contents are lower) than those specified by the DOP. Conversely, an underrun occurs when actual project releases are less (contents are higher) than those specified by the DOP. Flex accounts for Mica, Revelstoke, Arrow, and Duncan are offset each other at any point in time 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 741.03 m (2431.2 feet) on 31 July 2004. The Mica (Kinbasket) basin inflows were above normal during fall and winter 2004 - 2005 due to rainfall runoff. With above normal inflows combined with low discharge requirements from Mica for August through October 2004, Mica (Kinbasket) reservoir continued to refill to a maximum elevation for 2004 of 748.02 m (2454.1 feet) on 18 Oct, 6.36 m (20.9 feet) below full pool. As inflows gradually receded in November and December 2004 and outflows increased to meet winter load requirements, the reservoir drafted steadily, reaching 740.56 m (2429.7 feet) on 31 December 2004. The reservoir continued to draft January through late April 2005, reaching a minimum elevation of 724.91 m (2378.3 feet) on 21 April 2005, 1.40 m (4.6 feet) below the mean elevation for this date. Mica outflows from May through July 2005 were generally lower than normal. This reduction in outflows was made to maximize generation at the Peace River powerplants in order to minimize the risk of spill at Williston Reservoir (Peace River). This condition combined with above normal seasonal inflows resulted in continued filling of the reservoir to above normal levels, ending July 2005 at elevation 750.39 m (2461.9 feet) 1.77 m (5.8 feet) above the mean elevation for this date. Mica (Kinbasket reservoir) reached a maximum elevation for 2005 of 750.57 m (2462.5 feet) on 8 August, 3.81 m (12.5 feet) below full pool.

Inflow into Mica reservoir was slightly above normal over the period August 2004 to December 2004. Over this same period, Mica outflow varied from a monthly average low of 143 m^3/s (5050 cfs) in September to a monthly average high of 729 m^3/s (25,760 cfs) in December. Inflow into Mica reservoir was near normal over the period January 2005 to

July 2005. Outflow over this same period varied from a monthly average high of 906 m^3/s (32,000 cfs) in January to a monthly average low of 51 m^3/s (1,800 cfs) in June.

The Mica project had an underrun of 1935.6 cubic hectometers (hm^3) (791.2 thousand second-foot-days (ksfd) on 31 July 2004. The underrun was reduced to a minimum of 613.3 hm^3 (250.7 ksfd) on 25 February 2005 before reaching a maximum of 3679.2 hm^3 (1503.9 ksfd) on 3 August 2005. The Mica underrun as of 31 July 2005 was 3643.8 hm^3 (1489.4 ksfd).

The B.C. Hydro Non-Treaty Storage Agreement (NTSA) active storage account was at 814.7 hm^3 (333.0 ksfd) on 31 July 2004 and 912.53 hm^3 (373 ksfd) on 31 July 2005. The corresponding U.S. NTSA account was at 13.9 hm^3 (5.7 ksfd) and 234.1 hm^3 (95.7 ksfd), respectively. The NTSA Agreement terminated, with respect to release rights, on 30 June 2004. Under the NTSA Extended Provisions, active storage accounts must be refilled prior to 30 June 2011.

Revelstoke Reservoir

During the 2004-2005 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 feet) of its normal full pool elevation of 573.02 m (1,880.0 feet). During the spring freshet, March through July, the reservoir operated as low as elevation 571.65 m (1,875.5 feet), or 1.37 m (4.5 feet) below full pool, to provide additional operational space to control high local inflows. Changes in Revelstoke storage levels did not affect CRT storage operations.

Arrow Reservoir

As shown in Chart 6, the Arrow reservoir was at elevation 436.02 m (1430.5 feet) on 31 July 2004, 4.12 m (13.5 feet) below full pool. The reservoir reached its maximum of 436.24 m (1431.3 feet) on 12 August 2004, 3.9 m (12.7 feet) below full pool. Influenced by a low initial level, Arrow reservoir drafted to a below normal level, reaching 426.84 m (1400.4 feet) by 31 December 2004, 5.61 m (18.4 feet) below the mean elevation for this date. The reservoir reached its minimum level of the year at elevation 426.09 m (1397.9 feet) on 25 January 2005. The reservoir refilled from late January through July, reaching a maximum level of 434.63 m (1425.9 feet) on 1 July 2005, 5.5 m (18.1 feet) below full pool.

Local inflow into Arrow reservoir was slightly above normal over the period August to December 2004. Arrow outflow varied from a monthly average low of 818 m^3/s (28,900 cfs) in October to a monthly average high of 1515 m^3/s (53,500 cfs) in August. Daily outflows in December reached a peak of 1543 m^3/s (54,500 cfs) on 19 December before ramping down to 1293 m^3/s (45,700 cfs) by the end of the month, in preparation for the start of whitefish spawning. Local inflow into Arrow reservoir was 97 percent of normal over the period January to July 2005. Outflow over this same period varied from a monthly average high of 1679 m^3/s (59,300 cfs) in July to a monthly average low of 572 m^3/s (20,200 cfs) in April.

BCH has committed to DFO under the 22 September 2004 letter, to make efforts to continuing the historical winter flow reductions for whitefish protection. In this letter, developed as part of the Columbia Water Use Plan (WUP) process, BC Hydro promised to make efforts to protect whitefish over the 5-year period (2005-09) as follows: Tier 1 (0 to 20 percent egg mortality) in 3 out of 5 years, Tier 2 (20 to 40 percent egg mortality) in 2 out of 5 years, and 0 years with egg mortality greater than 40 percent. In order to achieve both U.S. and Canada nonpower needs, Arrow Reservoir operation was modified during the operating year under two Operating Committee Agreements. These agreements helped to enhance the success of whitefish and rainbow trout spawning and emergence downstream of the Arrow project in British Columbia and to provide additional non-power benefits in the U.S. From 1 January 2005 to 19 January 2005, Arrow outflow was held near 1416 m^3/s (50,000 cfs) to maintain low river levels during the whitefish peak spawning period. This operation reduced the number of eggs being dewatered during the incubation period in February and March 2005. Arrow outflow, from February through March 2005, was held above 736 m^3/s (26,000 cfs) to help protect deposited eggs. These flow changes resulted in the best (Tier 1 level) protection for whitefish for the 2004/2005 operating year. During April and May 2005, Arrow outflows were maintained at or above 566 m^3/s (20,000 cfs) to ensure successful rainbow trout spawning below Arrow, at water levels that could be maintained until hatch.

Duncan Reservoir

Operation of the Duncan reservoir in 2004 attempted to implement most of the operational constraints agreed upon in the recently completed Water Use Plan (WUP). As shown in Chart 7, the Duncan reservoir refilled late during 2004, reaching only 574.24 m

(1884.0 feet), 2.41 m (8.0 feet) below full pool on 1 August 2004. The reservoir continued to fill and recorded a maximum elevation of 576.45 m (1891.24 feet), 0.20 m (0.76 feet) below full pool on 17 August 2004. The reservoir was maintained within about 0.3 m (1.0 feet) below full pool through August as a flood buffer and to support recreation on the reservoir, as stipulated in the Duncan WUP.

The project passed inflows until 1 September 2004 when the reservoir started to draft. Discharges were increased to 227 m^3/s (8,000 cfs) through the first ten days of September to augment inflow into Kootenay Lake before reducing to 198 m^3/s (7,000 cfs) for the balance of September. There were a number of ramping tests conducted during the month when flows were dropped at various rates from 7 to 3 kcfs for a couple of hours per day to assess potential impact on fish. For the first 3 weeks of October discharges were reduced to maintain a 73 m^3/s (2,600 cfs) flow at the DRL (Duncan River below the Lardeau confluence) gauging station. Discharges were increased in the last week of October to bring DRL to a maximum flow of 110 m^3/s (3900 cfs) and maintained until 21 December 2004, when Duncan discharges were increased to 170 m^3/s (6,000 cfs) until the end of the year. For the first three weeks of January 2005, Duncan discharge was kept at 283 m^3/s (10,000 cfs) since the reservoir level was quite high at the beginning of the year, and to help reduce Arrow flows in aid of whitefish spawning. Given a low forecast for the 2005 freshet, BC Hydro requested a variance to the Duncan Flood Control Curve for 28 February 2005 from 551.0 m (1807.7 ft) to 552.4 m (1,812.5 ft), which was subsequently approved. The additional storage on 28 February increases the ability to maintain a minimum river flow at DRL of 73 m^3/s (2,600 cfs) for incubation of fish eggs during the March-April period as agreed to under the Duncan Water Use Plan. Flows were reduced to 200 m^3/s (7,000 cfs) in the last week of Jan and then gradually dropped to 160 m^3/s (5,600 cfs) by the end of Feb as the reservoir level dropped to 552.33 m (1,812.2 ft) on Feb 28, 2005. Discharges in March through the last week of May 2005 ranged from 40 m^3/s to 76 m^3/s (1,400 to 2,700 cfs) to provide a minimum flow of 73 m^3/s (2,600 cfs) at the DRL and to empty the reservoir prior to the freshet. The reservoir drafted to a minimum elevation of 547.56 m (1796.56 feet) on 21 April 2005, 0.69 m (2.4 feet) above empty.

Reservoir discharge was reduced to the minimum of 3 m^3/s (100 cfs) on 25 May 2005 to initiate refill. The observed seasonal water supply at Duncan for the February through September period was 91 percent of normal. The reservoir refilled to an elevation of 576.48

m, (1891.4 feet) on 31 July 2005, 0.17 m (0.6 feet) below full pool. Through the balance of August, the reservoir was maintained within 0.15 m (0.5 feet) range around the target elevation of 576.36 m (1,891.0 ft), to provide a flood buffer and to support recreation on the reservoir, as stipulated in the Duncan WUP.

In September 2005, Duncan discharge was increased to 200 m^3/s (7,000 cfs) to draft the reservoir prior to the start of kokanee and whitefish spawning. Discharges were reduced to 73 m^3/s (2,600 cfs) in October to facilitate spawning at lower flows to limit the risk of over-winter dewatering of redds.

Libby Reservoir

Lake Koocanusa began July near elevation 745.73 m (2446 ft). Inflow ranged from 679 m^3/s (24 kcfs) near the beginning of the month to a low of 170 m^3/s (6 kcfs) at the end of the month. Outflow was held at 354 m^3/s (12.5 kcfs) through the month of July per a Technical Management Team (TMT) recommendation on 23 June 2004 to maintain constant flows at Libby and draft to 743.6 m (2439 ft) by 31 August. Libby reached a peak elevation of 747.04 m (2450.3 ft) on 22 July 2004 . Inflow averaged near 283 m^3/s (10 kcfs) for the month of August, 105 percent of average. As August progressed, it became evident that Libby would not draft to elevation 743.6 m (2439 ft) by 31 August with flat outflows of 354 m^3/s (12.5 kcfs). TMT agreed to maintain the flat flows through August and into September until elevation 743.6 m (2439 ft) was reached. Above normal precipitation near the end of August caused an increase in inflows and the project filled .3 m (1 ft) across the last week of the month, reaching elevation 745.4 m (2445.0 ft) on 31 August 2004.

Due to heavy precipitation in August, Lake Koocanusa began September near elevation 745.4 m (2445.0 feet). Inflows remained high into September, and it became clear that the project would not reach elevation 743.6 m (2439 ft) at the end of September with 354 m^3/s (12.5 kcfs) outflow. This was a goal expressed at TMT in August. At the 15 September 2004 TMT meeting, the group decided to keep weekly average flows between 255 m^3/s (9 kcfs) and 354 m^3/s (12.5 kcfs) while allowing weekly shaping for power needs. Project outflow was maintained at 354 m^3/s (12.5 kcfs) until 12 September 2004 when the project began weekly shaping. Flows were increased to 396 m^3/s (14 kcfs) on 13 September 2004 and held there for a few days, then ramped down to 272 m^3/s (9.6 kcfs) by 18 September 2004. Flows were then maintained at 272 m^3/s (9.6 kcfs) for the remainder of the month. September inflow averaged

357 m^3/s (12.6 kcfs), 192 % of average. Outflow averaged 317 m^3/s (11.2 kcfs) through the month, and the project reached elevation 746.0 m (2446.8 feet) by the end of September. Inflow averaged 190 m^3/s (6.7 kcfs), 123% of average, for the month of October. Outflows were maintained at 272 m^3/s (9.6 kcfs) for the first week of October and then reduced to 133 m^3/s (4.7 kcfs), or one small unit for the remainder of the month. Outflow averaged 175 m^3/s (6.2 kcfs) and the project ended October at elevation 746.2 m (2447.5 ft).

Lake Koocanusa began November near elevation 746 m (2447.5 ft). Outflow in November was increased and was shaped on a weekly basis to meet power needs for the first half of the month with higher flows weekdays (nearly 538 m^3/s or 19 kcfs) and lower flows on weekends (near 368 m^3/s or 13 kcfs). Flow was ramped down over the week of Thanksgiving and stayed down for most of the remainder of the month. The project ended the month of November at elevation 742.5 m (2435.5 ft). The Salmon Managers submitted a System Operational Request (SOR) to the action agencies on 5 November, requesting the coolest water available using Libby's selective withdrawal system to meet burbot needs. A flow request for burbot was not specified in the SOR. The December Final water supply forecast (WSF) at Libby was 7.62 km^3 (6.18 MAF), or 99 % of the 30-year average, which required an end of December elevation of 735.06 m (2411 ft). In order to draft Libby down to elevation 735.06 m (2411 ft), outflows from Libby were ramped up to full load (near 707 m^3/s or 25 kcfs) over several days beginning on 30 November. The outflows followed a weekly load shape with higher flows on weekdays and lower flows on weekends. Flows were held flat at near 566 m^3/s (20 kcfs) during Christmas week and increased back up to 707 m^3/s (25 kcfs) for one day (28 Dec) after the holiday and then ramped down to minimum flow, following BiOp ramping rates, by 8 January 2005.

Lake Koocanusa began January near elevation 734.8 m (2410 ft). Outflows during most of the month were at a minimum of 113 m^3/s (4 kcfs). The project ended the month of January at elevation 735.2 m (2411.5 ft). The January Final WSF at Libby was 7.14 km^3 (5.786 MAF), or 92.6 % of the 30-year average, which required an end of the month VARQ flood control elevation of 738.1 m (2420.9 ft). Elevations were more than 3.05 m (10 ft) below Flood Control at the end of January. The same trends were seen in the Month of February. The project ended at an elevation of 735.5 m (2412.6 ft) and outflows were held at 113 m^3/s (4 kcfs) for the entire month. The February Final WSF at Libby was 6.94 km^3 (5.63 MAF), or 90% of the 30-year average. This required an end of February VARQ flood control elevation of 741.7 m (2432.9 ft). Elevations at Libby were close to 6.1 m (20 ft) below Flood Control at the end of the month.

Lake Koocanusa began March near elevation 735.5 m (2412.6 ft). Outflows in during the month were at a minimum of 113 m^3/s (4 kcfs). The project ended the month of March at elevation 735.7 m (2413.2 ft). The March Final WSF at Libby was 6.62 km^3 (5.37 MAF), or 86.0% of the 30 year average, which required an end of the month VARQ flood control elevation of 744.5 m (2442.0 ft). Elevations were more than 8.5 m (28 ft) below Flood ZControl at the end of March. During the month of April, outflows were held at 113 m^3/s (4 kcfs). The project ended the month at an elevation of 737.5 m (2419 ft). The April Final WSF at Libby was 6.66 km^3 (5.40 MAF), or 86.4% of the 30-year average. This would require an end of April VARQ flood control elevation of 744.6 m (2442.3 ft). Elevations at Libby were around 7 m (23 ft) below Flood Control at the end of April.

Lake Koocanusa began May at elevation 737.5 m (2419 ft). The May Final WSF at Libby was 6.29 km^3 (5.096 MAF), or 81.7% of the 30 year average. This volume forecast level requires a .984 km^3 (800 kaf) volume for a sturgeon pulse in the May – June time frame. Flows continued at 113 m^3/s (4 kcfs) until 19 May when the USFWS sturgeon pulse operation was started. Flows were raised to 707 m^3/s (25 kcfs) through 26 May. After that time, flows were lowered and held at various levels through 2 June. This operation provided flows sufficient to allow the U.S. Geological Survey to gather basic field measurements necessary to expand their flow and sediment transport modeling throughout the “braided reach” of the Kootenai River. The findings of this work were important for defining both the evolving habitat strategies, and spill tests to provide for sturgeon needs. The project ended the month of May at elevation 743.3 m (2438.0 ft). The June Final WSF at Libby was 5.821 km^3 (4.72 MAF), or 75.6 % of the 30-year average. Starting 3 June, a flat flow of 396 m^3/s (14 kcfs) was chosen to draft the reservoir 6.1 m (20 ft) from full by the end of August. However, unseasonable rainfall in the basin caused inflow to spike above 1132 m^3/s (40 kcfs) on 7-8 and 19-20 June. The project responded by increasing to full load discharge (about 685 m^3/s or 24.2 kcfs) on 15 June and operated at this level through 4 July.

Lake Koocanusa began July near elevation 749.1 m (2457 ft). The project started the month with outflows of 685 m^3/s (24.2 kcfs) and on 5 July outflows were reduced to about 546 m^3/s (19.3 kcfs). This flow was the flat flow needed, based on the 28 June forecast, to reach 743.6 m (2439 ft) by the end of August. Until about mid -month flow was kept between 538

m^3/s (19 kcfs) and full powerhouse, 679 m^3/s (24 kcfs), in order to control rate of fill and to provide space for late season rain events and snowmelt. Inflow ranged from 821 m^3/s (29 kcfs) near the beginning of the month to a low of 283 m^3/s (10 kcfs) at the end of the month. Outflow for the month averaged 611 m^3/s (21.6 kcfs). Libby reached a peak elevation of 749.5 m (2458.4 ft) (.18 m or 0.6 ft from full) on 10 July 2005. The state of Montana submitted draft and final SORs (SOR 2005-MT-1) to the TMT on 29 June and 6 July 2005 asking the TMT implement the Northwest Planning and Conservation Council (NWPCC) Mainstem Amendments. The request was to draft to 743.6 m (2439 ft) (6.1 m or 20 ft from full) by the end of September rather than the end of August as specified in the BiOp. On 28 June USFWS and Columbia River Intertribal Fish Commission (CRITFC) submitted SOR-2005-16 requesting the BiOp-specified draft to 743.6 m (2439 ft). The final decision was to draft to elevation 743.6 m (2439 ft) by the end of August. Actual ending August elevation was 743.8 m (2439.5 ft). For August, the operational goal was to gradually ramp down flows while meeting the agreed elevation target. Outflow was near 537.6 m^3/s (19 kcfs) at the end of the July and was gradually reduced to 339.6 m^3/s (12 kcfs) near the end of August.

Kootenay Lake

As shown in Chart 9, the level of Kootenay Lake at Queens Bay was at elevation 531.38 m (1743.4 ft) on 31 July 2004. By 2 November 2004, Kootenay Lake was drafted to 531.06 m (1742.4 ft), 0.89 m (2.9 feet) below the maximum IJC level. The lake refilled in November due to increased discharges from Libby and was operated to within 0.8 ft of the IJC in December.

Kootenay Lake was drafted during January to April 2005 to remain below the maximum IJC level and to meet generation requirements. Discharges from the lake were kept to the maximum possible through Grohman Narrows (a hydraulic restriction on lake discharges) until 17 May 2005. On 20 April 2005, Kootenay Lake was at its minimum elevation for the year of 529.9 m (1738.6 ft).

The Kootenay Lake Board of Control declared the commencement of the spring rise for the regulation of Kootenay Lake on 25 April 2005 when Brilliant began to spill. Following the declaration of spring freshet, Kootenay Lake was operated in accordance to the IJC lowering formula.

Kootenay Lake discharge was increased in accordance with the IJC order for Kootenay Lake. Inflow peaked at 1838 m^3/s (64,900 cfs) on 18 June 2005. Discharge from the lake peaked at 1433 m^3/s (50,600 cfs) on 24 June 2005. Kootenay Lake reached a peak elevation of 532.56 m (1747.33 ft) on 23 June 2005.

As runoff receded during July, Kootenay Lake reservoir began to draft and discharges were adjusted to control reservoir levels slightly below the IJC limits. When the Kootenay Lake level measured at Nelson was drafted below the trigger elevation of 531.36 m (1743.32 ft) on 6 August 2005, discharges were adjusted to keep the lake level at or below the control level until the end of August. On 31 August 2005, the Kootenay Lake level measured at Queens Bay was at elevation 531.48 m (1743.7 ft).

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. Consistent with all DOP's prepared since the installation of generation at Mica, the 2004-2005 and 2005-2006 DOP's 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 are developed through Critical Rule Curves (CRC), Assured Refill Curves (ARC) and Variable Refill Curves (VRC). The VRCs 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 calculation for Mica, Arrow and Duncan are shown in Tables 2 – 4 and 2M – 4M.

The calculation for Libby VRCs is shown in Tables 5 and 5M. Libby VRCs are used in preparation of the Treaty Storage Regulation (TSR).

During the period covered by this report, Libby power operations in the TSRs were developed in accordance with the CRT and the 2003 CRT FCOP (with slight modifications and typographic corrections made on 14 February 2005). Libby operated to Principal Component Methodology flood control in December. This new methodology develops early season forecasts in November and December and allows for Libby to not draft as heavily in December if the December forecast is less than 85% of normal. Libby operated to VARQ (Variable flow) flood control in the January – spring period. During the fall period from September through December 2004, Libby operated for power purposes according to the PNCA AER. From mid-January through 17 May 2005 the outflow from Libby Dam was at minimum that enhanced refill and in the early part of the period, enhanced burbot movement in the Kootenai River. The USFWS-requested sturgeon pulse took place 18 May – 2 June 2005. From June 2 through August, Libby operated for flood control and as recommended by TMT for flow augmentation per the 2000 U.S. Fish and Wildlife Service (USFWS) and 2004 National Marine Fisheries Service (NMFS now called NOAA Fisheries) Biological Opinions (BiOps).

Flood Control

While the 2005 water supply forecasts averaged below normal across the Columbia River Basin, the reservoir system, including the Columbia River Treaty projects were still required to draft for flood control in preparation for the spring freshet. Inflow forecasts and reservoir regulation modeling were done weekly throughout the winter and spring. Projects were operated according to the 2003 Flood Control Operating Plan. The unregulated peak flow at The Dalles, Oregon, shown on Chart 13, is estimated at 12,704 m^3/s (448,672 cfs) on 22 May 2005 and a regulated peak flow of 8,113 m^3/s (286,500 cfs) occurred on 18 May 2005. The unregulated peak stage at Vancouver, Washington was calculated to be 4.62 m (15.1 ft) on 23 May 2005 and the highest-observed stage was 2.94 m (9.7 ft) on 22 May 2005.

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. Low runoff conditions last year and slightly below normal runoff conditions this year caused Mica to be drafted very deeply for power. There were no daily operations specified for Arrow, and the projects were able to meet both fish flow and flood control objectives. In operating year 2003-2004 Mica and Arrow operated to “shifted” flood control as defined in the 2003 FCOP.

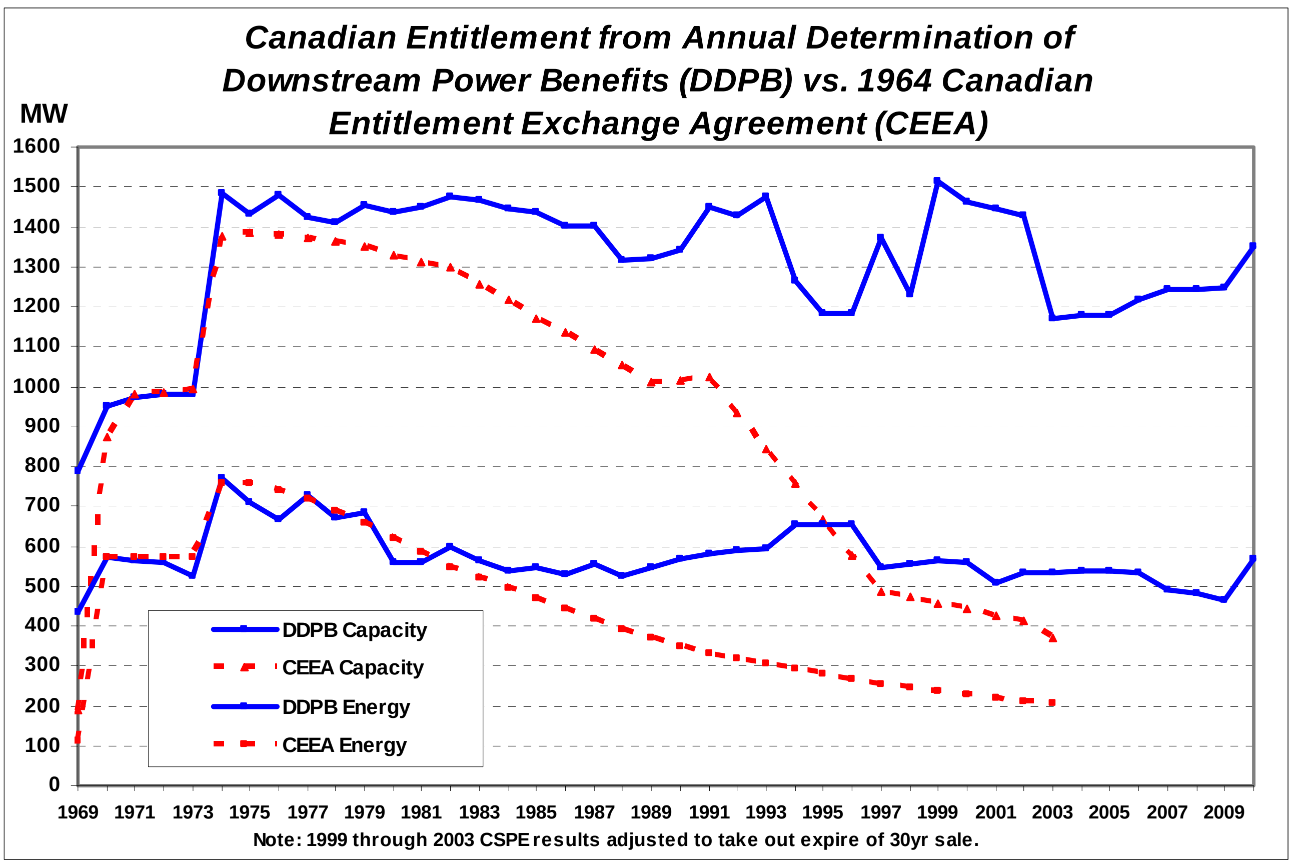
The Canadian Entity has selected to operate Mica and Arrow to the flood control storage allocations of 4.44 km^3 (3.6 Maf) maximum draft at Arrow and 5.03 km^3 (4.08 Maf) maximum draft at Mica, and the operating committee agreed on 16 July 2003.

Computations of the Initial Controlled Flow (ICF) for system flood control operation were made in accordance with the Treaty Flood Control Operating Plan. The computed ICF at The Dalles was 7,963 m^3/s (281,223 cfs) on 1 January 2005; 7,158 m^3/s (252,796 cfs) on 1 February 2005; 5,663 m^3/s (200,000 cfs) on 1 March; 5,663 m^3/s (200,000 cfs) on 1 April 2005; and 5,663 m^3/s (200,000 cfs) on 1 May 2005. As mentioned earlier, the observed peak flow at The Dalles was 8,113 m^3/s (286,500 cfs) on 18 May 2005. Data for the 1 May ICF computation is given in Table 6.

Canadian Entitlement

From 1 August 2004 through 30 September 2005, the U.S. Entity delivered the Canadian Entitlement to downstream power benefits from the operation of Canadian Treaty storage to the Canadian Entity, at existing points of interconnection on the Canada-U.S. border. The amounts returned, not including transmission losses and scheduling adjustments, are listed in Section III of this report under the heading Canadian Entitlement. During 1 July 2004 through 31 October 2004, the Entitlement's owner, the Province of British Columbia, entered into a short-term disposal in the United States of up to 400 MW, using specific provisions of the 29 March 1999 Agreement on "Disposals of the Canadian Entitlement Within the U.S. for 1 April 1998 through 15 September 2024. When the agreement expired at the end of October, the power delivery obligation reverted to the U.S.-Canada border.

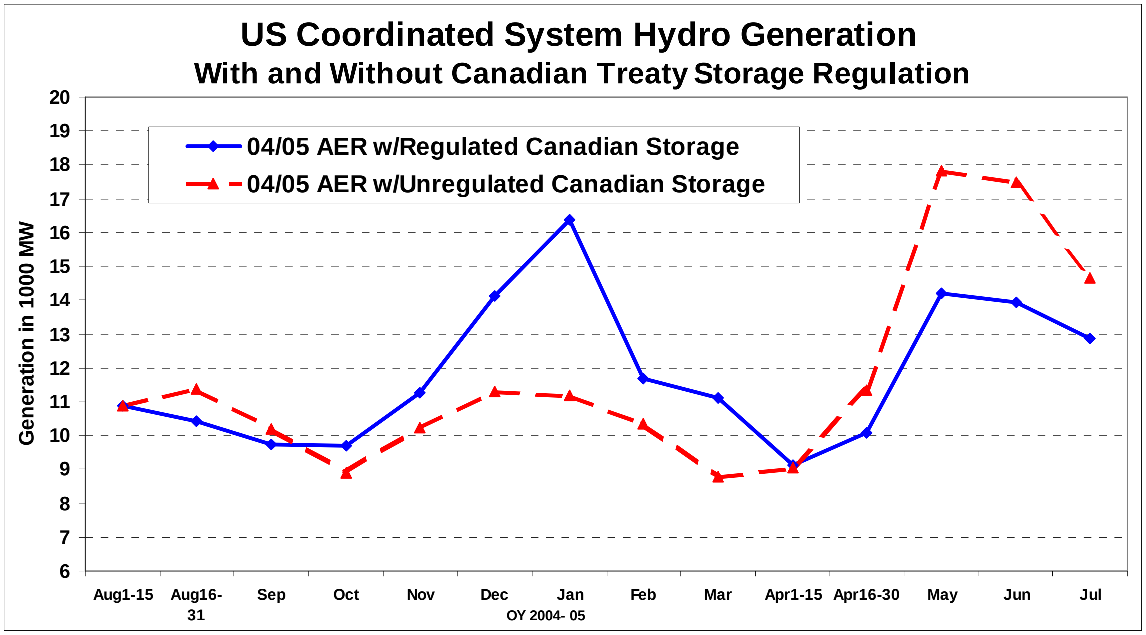
The following graph shows the historic Canadian Entitlement computation from the DDPB studies together with the amount sold under the CEPA.



In accordance with the Canadian Entitlement Allocation Extension Agreement, dated April 1997, 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).

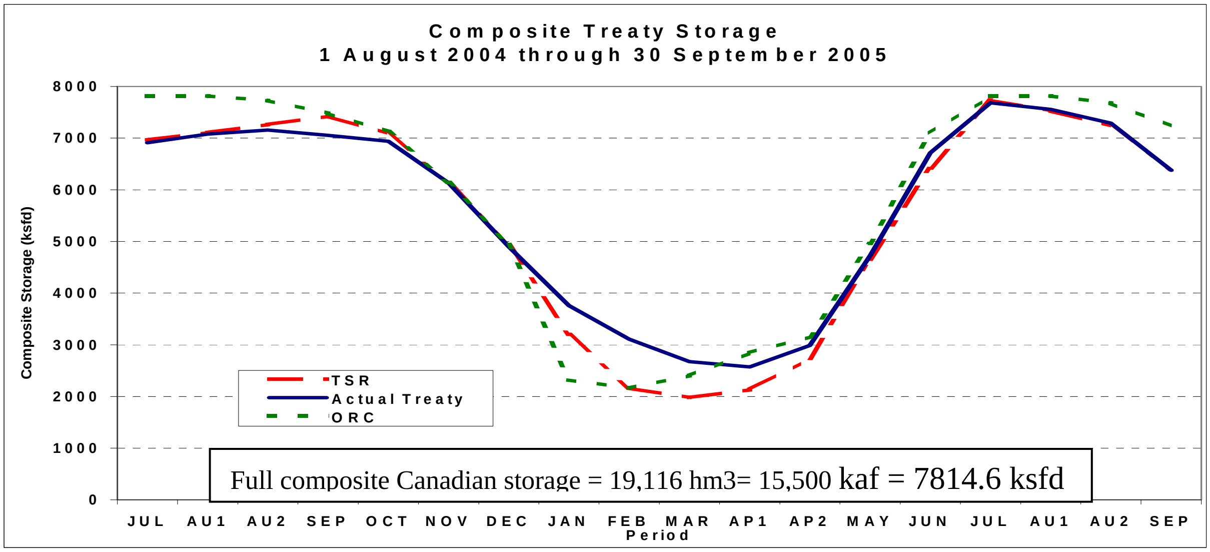
Power Generation and other Accomplishments

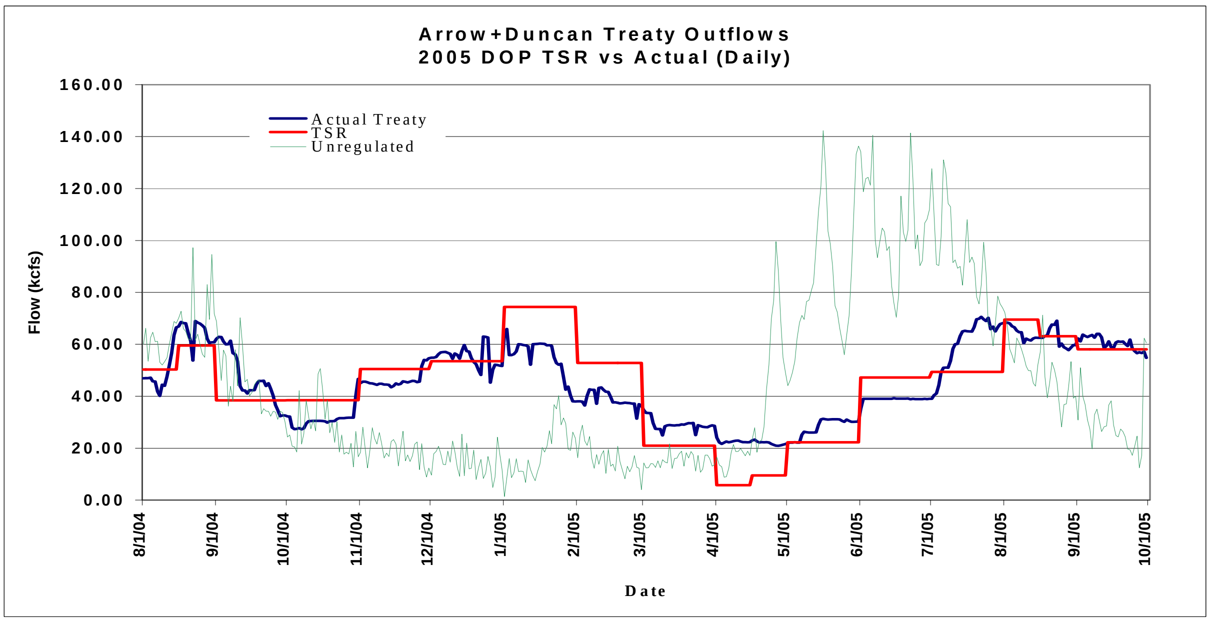
Actual U.S. power benefits from the operation of CRT storage are unknown and can only be roughly estimated. Treaty storage has such a large impact on the U.S. system operation that its absence would significantly affect operating procedures, non-power requirements, loads and resources, and market conditions, thus making any benefit analysis highly speculative. The following graph shows a rough estimate of the average monthly impact on downstream U.S. power generation during the 2004-2005 operating year, with and without the regulation of Canadian storage, based on the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER) that includes minimum flow and spill requirements for U.S. fishery objectives. The increase in average annual U.S. power generation due to the operation of Canadian storage, as measured by the PNCA AER, was 252 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.



Based on the authority from the 2004-2005 and 2005-2006 DOPs, the Operating Committee completed several supplemental operating agreements, described in Section III, which resulted in power and other benefits both in Canada and the U.S. Other benefits include changes to streamflows below Arrow that enhanced trout and mountain whitefish spawning in Canada and the downstream migration of salmon in the U.S.

The following chart compares the actual operation of the composite Canadian Treaty Storage to the results of the DOP TSR study, and the subsequent graph shows the difference in Arrow plus Duncan regulated outflows in the DOP TSR and the actual daily CRT outflows due to these agreements. The daily unregulated streamflow is also shown for comparison purposes.





At the beginning of the 2003-2004 operating year, the TSR storage level for Canadian storage was only 89.1 percent full, and the actual Canadian storage was slightly below 88.5 percent full.

In September, under terms of the LCA, Canada returned LCA provisional draft and the parties targeted the TSR content at the end of the month. However, as of 30 September 2004, Composite Canadian Treaty storage content was approximately 905 hm^3 (370 ksfd) below the DOP TSR as a result of inadvertent draft caused when the end-of-September TSR storage target increased by almost 470 ksfd late in the month. A similar situation occurred in October when the Canadian Treaty storage content of about 347 hm^3 (142 ksfd) below the TSR was reached, again the result of a large change in the TSR late in the month. By the end of November, Composite Canadian Treaty storage was on the TSR target.

In December 2004, The Canadian Entity again exercised provisional draft rights under the LCA, drafting 171 hm^3 (70 ksfd) below TSR levels by month-end. Also in December, the U.S. and Canada reached agreement to shape flows from December through July to meet multiple system requirements and fishery needs.

In January and early February 2005, the U.S. stored water for flow augmentation in Mica resulting in an Arrow discharge of about 1415 m^3/s (50 kcfs) for whitefish spawning. In February, water was stored for release in March to provide more suitable flows for whitefish. The maximum level above TSR was reached in February when composite Canadian Treaty Storage reached about 2300 hm^3 (940 ksfd) above the TSR storage content. All LCA provisional draft was returned by early March.

In April, Arrow actual outflows were reduced to about 566 m^3/s (20 kcfs) to balance the needs of B.C. trout spawning, U.S. fisheries needs, and system load requirements, ending April with composite Treaty storage about 611 hm^3 (250 ksfd) above the DOP TSR. Arrow outflows were increased in late May and June to meet U.S. fishery needs and flood control requirements. The balance of flow augmentation storage was released in July resulting in relatively high Arrow outflows to help meet U.S. fisheries' flows. The sum of Canadian Treaty storage ended July slightly below DOP TSR levels. Treaty projects remained near TSR levels until late September when the Canadian Entity exercised provisional draft totaling 68.5 hm^3 (28 ksfd) under the LCA.

TABLES

Table 1: Unregulated Runoff Volume Forecasts

Million Acre-feet
2005

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

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.00	23.00	10.88	5.79	74.3
February	2.01	22.79	11.00	5.78	69.2
March	1.97	22.27	10.45	5.51	57.2
April	1.97	21.53	10.35	5.52	60.8
May	1.88	20.31	10.14	5.24	61.9
June	1.89	20.26	10.18	4.72	67.3
Actual	1.84	20.30	10.53	5.58	68.4

NOTE: These data were used in actual operations. Subsequent revisions have been made in some cases.

Table 1M: Unregulated Runoff Volume Forecasts

Cubic Kilometers
2005

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	2.47	28.37	13.41	7.14	91.65
February	2.48	28.11	13.57	7.13	85.36
March	2.43	27.47	12.88	6.79	70.56
April	2.43	26.56	12.77	6.81	75.00
May	2.31	25.06	12.50	6.46	76.35
June	2.33	24.98	12.56	5.83	83.01
Actual	2.26	25.04	12.98	6.88	84.43

NOTE: These data were used in actual operations. Subsequent revisions have been made in some cases.

Table 2: 2005 Variable Refill Curve

Mica Reservoir

		Initial	1-Jan	1-Feb	1-Mar	1-Apr	1-May	1-Jun
PROBABLE DATE 31JULY INFLOW,KAF			9005.1	9108.2	8435.8	8108.5	7355.8	5292
PROBABLE DATE 31JULY INFLOW,KSFD	**		4540	4592	4253	4088	3708.5	2668
95% FORECAST ERROR FOR DATE, IN KSFD			653	510.4	465.4	444.5	360.5	360.5
95% CONF.DATE-31JULY INFLOW, KSFD	1/		3887	4081.6	3787.6	3643.5	3348	2307.5
ASSUMED FEB1-JUL31 INFLOW, % OF VOL			100					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		3887					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4300					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		2262.7					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1904.9					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2439.7					
JAN31 ORC, FT	7/		2431.3					
BASE ECC, FT	8/	2431.3						
LOWER LIMIT, FT		2401.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.6	97.6				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		3793.7	3983.6				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4300	4700				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		2143.7	2163.3				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1879.2	1708.9				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2438.7	2433.5				
FEB28 ORC, FT	7/		2427.7	2427.7				
BASE ECC, FT	8/	2427.7						
LOWER LIMIT, FT		2395.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.1	95.1	97.4			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		3696.5	3881.6	3689.1			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4300	4700	5000			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		2011.8	2018.2	2023			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1844.5	1665.8	1863.1			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2436.4	2432.6	2436.8			
MAR31 ORC, FT	7/		2427.8	2427.8	2427.8			
BASE ECC, FT	8/	2427.8						
LOWER LIMIT, FT		2394.1						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90	90	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		3498.3	3673.4	3492.2	3450.4		
MAY MINIMUM FLOW REQUIREMENT, CFS	3.		5000	5000	5000	5000		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1873	1873	1873	1873		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1903.9	1728.8	1910	1951.8		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2437.6	2433.9	2439.9	2438.6		

APR30 ORC, FT	7/		2428.3	2428.3	2428.3	2428.3		
BASE ECC, FT	8/	2428.3						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		2783.1	2922.4	2776.3	2743.5	2661.7	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		18000	18000	18000	18000	18000	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		1718	1718	1718	1718	1718	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2464.1	2324.8	2470.9	2503.7	2585.5	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2449.2	2446.4	2449.4	2450	2451.7	
MAY31 ORC, FT	7/		2444.8	2444.8	2444.8	2444.8	2444.8	
BASE ECC, FT	8/	2444.8						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			35.5	35.5	36.3	37.3	39.4	49.5
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1379.9	1449	1374.9	1359	1319.1	1142.2
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		38000	38000	38000	38000	38000	38000
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		1178	1178	1178	1178	1178	1178
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3327.3	3258.2	3332.3	3348.2	3388.1	3529.2
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2466.2	2464.9	2466.3	2466.6	2467.4	2470.1
JUN30 ORC, FT	7/		2466.2	2464.9	2466.3	2466.3	2466.3	2466.3
BASE ECC, FT	8/	2466.3						
JUL 31 ECC, FT			2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

<u>Notes</u>:
** Forecast start date is 1 Feb. or Later. Observed inflow from 1 Jan. – Date is subtracted. .
1/ Probable inflow minus (95% error & Jan.1-Dateinflow).
2/ Preceding line times 1/.
3/ Power Discharge Requirement.
4/ Cumulate minimum outflow from 3/, Date to July
5/ Full Content (3529.2 ksfd) plus 4/ minus /2.
6/ Elevation from 5/, interpolated from Storage/Elev. Table
7/ Lower of elevation from 6/ or Base ECC (Initial), not less than ORC Lower Limit, not more than Flood Control
8/ Higher of ARC or CRC1 in DOP

Table 2M: 2005 Variable Refill Curve

Mica Reservoir

		INITIAL	1-Jan	1-Feb	1-Mar	1-Apr	1-May	1-Jun
PROBABLE DATE-31JULY INFLOW, KM^3			11.11	11.23	10.41	10.00	9.07	6.53
PROBABLE DATE-31JULY INFLOW, HM^3	**		11107.6	11234.8	10405.4	10001.7	9073.2	6527.5
95% FORECAST ERROR FOR DATE, HM^3			1597.6	1248.7	1138.6	1087.5	882.0	882.0
95% CONF.DATE-31JULY INFLOW, HM^3	1/		9509.9	9986.0	9266.7	8914.2	8191.2	5645.5
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		9509.9					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		121.8					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/		5535.9					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		4660.5					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		743.6					
JAN31 ORC, M	7/		741.1					
BASE ECC, M	8/	741.1						
LOWER LIMIT, M		732.0						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.6	97.6				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		9281.7	9746.3				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		121.8	133.1				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		5244.8	5292.7				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		4597.7	4181.0				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		743.3	741.7				
FEB28 ORC, M	7/		740.0	740.0				
BASE ECC, M	8/	740.0						
LOWER LIMIT, M		730.1						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.1	95.1	97.4			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		9043.9	9496.7	9025.8			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		121.8	133.1	141.6			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		4922.1	4937.7	4949.5			
VRC Mar31 Reservoir Content, hm^3	5/		4512.8	4075.5	4558.3			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		742.6	741.5	742.7			
MAR31 ORC, M	7/		740.0	740.0	740.0			
BASE ECC, M	8/	740.0						
LOWER LIMIT, M		729.7						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90	90	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		8558.9	8987.3	8544.0	8441.7		

MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		141.6	141.6	141.6	141.6		
MIN MAY1-JUL31 OUTFLOW, HM^3	4/		4582.5	4582.5	4582.5	4582.5		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		4658.1	4229.7	4673.0	4775.3		
VRC APR30 RESERVOIR CONTENT, METERS	6/		743.0	741.9	743.7	743.3		
APR30 ORC, M	7/		740.1	740.1	740.1	740.1		
BASE ECC, M	8/	740.1						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		6809.1	7149.9	6792.5	6712.2	6512.1	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		509.7	509.7	509.7	509.7	509.7	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		4203.3	4203.3	4203.3	4203.3	4203.3	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		6028.7	5687.9	6045.3	6125.6	6325.7	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		746.5	745.7	746.6	746.8	747.3	
MAY31 ORC, M	7/		745.2	745.2	745.2	745.2	745.2	
BASE ECC, M	8/	745.2						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			35.5	35.5	36.3	37.3	39.4	49.5
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		3376.1	3545.1	3363.8	3324.9	3227.3	2794.5
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		1076.0	1076.0	1076.0	1076.0	1076.0	1076.0
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		2882.1	2882.1	2882.1	2882.1	2882.1	2882.1
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		8140.6	7971.5	8152.8	8191.7	8289.3	8634.5
VRC JUN30 RESERVOIR CONTENT, METERS	6/		751.7	751.3	751.7	751.8	752.1	752.9
JUN30 ORC, M	7/		751.7	751.3	751.7	751.7	751.7	751.7
BASE ECC, M	8/	751.7						
JUL 31 ORC, M			752.9	752.9	752.9	752.9	752.9	752.9

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (8634.5 HM^3) 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 3: 2005 Variable Refill Curve

Arrow Reservoir

		INITIAL	1-Jan Total	1-Feb Total	1-Mar Total	1-Apr Total	1-May Total	1-Jun Total
PROBABLE DATE 31JULY INFLOW,KAF			20176.2	19973.8	19007.9	17694.8	14967.8	10018.7
& IN KSFD	**		10172	10070	9583	8921	7546.2	5051
95% FORECAST ERROR FOR DATE, IN KSFD			1233.4	987.3	825.2	715.6	501.7	501.7
95% CONF.DATE-31JULY INFLOW, KSFD	1/		8938.6	9082.7	8757.8	8205.4	7044.5	4549.3
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		8938.6					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		3956					
UPSTREAM DISCHARGE, KSFD	4/		1922.6					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		519.6					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1389.9					
JAN31 ORC, FT	7/		1389.9					
BASE ECC, FT	8/	1409.5						
LOWER LIMIT, FT		1384.4						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.5	97.5				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		8715.1	8855.7				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		3816	3816				
UPSTREAM DISCHARGE, KSFD	4/		2089.9	2089.9				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		770.4	629.8				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1395.1	1392.2				
FEB28 ORC, FT	7/		1395.1	1392.2				
BASE ECC, FT	8/	1411.2						
LOWER LIMIT, FT		1379						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.4	94.4	96.9			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		8438	8574.1	8486.3			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		3661	3661	3661			
UPSTREAM DISCHARGE, KSFD	4/		2083.2	2083.2	2083.2			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		885.8	749.7	837.5			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1397.5	1394.7	1396.5			
MAR31 ORC, FT	7/		1397.5	1394.7	1396.5			
BASE ECC, FT	8/	1411.4						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.5	87.5	89.8	92.6		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		7821.3	7947.4	7864.5	7598.2		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		3511	3511	3511	3511		
UPSTREAM DISCHARGE, KSFD	4/		2060.6	2060.6	2060.6	2060.6		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1329.9	1203.8	1286.7	1553		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1406.1	1403.7	1405.3	1410.3		
APR30 ORC, FT	7/		1406.1	1403.7	1405.3	1410.3		
BASE ECC, FT	8/	1413.7						

ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.5	65.5	67.2	69.3	74.9	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		5854.8	5949.2	5885.2	5686.4	5276.3	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		3356	3356	3356	3356	3356	
UPSTREAM DISCHARGE, KSFD	4/		1283.9	1283.9	1283.9	1283.9	1283.9	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2364.7	2270.3	2334.3	2533.1	2943.2	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1424.6	1423	1424	1427.4	1434.1	
MAY31 ORC, FT	7/		1424.6	1423	1424	1425.6	1425.6	
BASE ECC, FT	8/	1425.4						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.3	30.3	31.1	32.1	34.7	46.3
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		2708.4	2752.1	2723.7	2633.9	2444.4	2106.3
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		1736	1736	1736	1736	1736	1736
UPSTREAM DISCHARGE, KSFD	4/		201.9	271	199.1	199.1	199.1	199.1
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3007.5	3025.8	3039.6	3039.6	3070.3	3408.4
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1431.9	1432.3	1431.6	1433.1	1436.1	1441.4
JUN30 ORC, FT	7/		1435.1	1435.4	1435.6	1435.6	1436.1	1438.2
BASE ECC, FT	8/	1438.2						
JUL 31 ECC, FT			1444	1444	1444	1444	1444	1444

** 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 3M: 2005 Variable Refill Curve

Arrow Reservoir

		INITIAL	1-Jan Total	1-Feb Total	1-Mar Total	1-Apr Total	1-May Total	1-Jun Total
PROBABLE DATE-31JULY INFLOW, KM^3			24.9	24.6	23.4	21.8	18.5	12.4
& IN HM^3	**		24886.8	24637.3	23445.8	21826.1	18462.5	12357.8
95% FORECAST ERROR FOR DATE, IN HM^3			3017.6	2415.5	2018.9	1750.8	1227.5	1227.5
95% CONF.DATE-31JULY INFLOW, HM^3	1/		21869.2	22221.7	21426.8	20075.3	17235.1	11130.3
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		21869.2					
MIN FEB1-JUL31 OUTFLOW, HM^3	3/		9678.7					
UPSTREAM DISCHARGE, HM^3	4/		4703.8					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		1271.3					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		423.64					
JAN31 ORC, M	7/		423.64					
BASE ECC, M	8/	429.62						
LOWER LIMIT, M		421.97						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.5	97.5				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		21322.4	21666.4				
MIN MAR1-JUL31 OUTFLOW, HM^3	3/		9336.2	9336.2				
UPSTREAM DISCHARGE, HM^3	4/		5113.1	5113.1				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		1884.9	1540.9				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		425.23					
FEB28 ORC, M	7/		425.23					
BASE ECC, M	8/	430.13						
LOWER LIMIT, M		420.32						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.4	94.4	96.9			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		20644.4	20977.4	20762.6			
MIN APR1-JUL31 OUTFLOW, HM^3	3/		8957.0	8957.0	8957.0			
UPSTREAM DISCHARGE, HM^3	4/		5096.8	5096.8	5096.8			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		2167.2	1834.2	2049.0			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		425.96					
MAR31 ORC, M	7/		425.96					
BASE ECC, M	8/	430.19						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.5	87.5	89.8	92.6		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		19135.6	19444.1	19241.3	18589.8		

MIN MAY1-JUL31 OUTFLOW, HM^3	3/		8590.0	8590.0	8590.0	8590.0		
UPSTREAM DISCHARGE, HM^3	4/		5041.5	5041.5	5041.5	5041.5		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		3253.7	2945.2	3148.0	3799.6		
VRC APR30 RESERVOIR CONTENT, METERS	6/		428.58					
APR30 ORC, M	7/		428.58					
BASE ECC, M	8/	430.90						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			65.5	65.5	67.2	69.3	74.9	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		14324.4	14555.3	14398.7	13912.3	12909.0	
MIN JUN1-JUL31 OUTFLOW, HM^3	3/		8210.8	8210.8	8210.8	8210.8	8210.8	
UPSTREAM DISCHARGE, HM^3	4/		3141.2	3141.2	3141.2	3141.2	3141.2	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		5785.5	5554.5	5711.1	6197.5	7200.8	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		434.22					
MAY31 ORC, M	7/		434.22					
BASE ECC, M	8/	434.46						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.3	30.3	31.1	32.1	34.7	46.3
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		6626.4	6733.3	6663.8	6444.1	5980.5	5153.3
MIN JUL1-JUL31 OUTFLOW, HM^3	3/		4247.3	4247.3	4247.3	4247.3	4247.3	4247.3
UPSTREAM DISCHARGE, HM^3	4/		494.0	663.0	487.1	487.1	487.1	487.1
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		7358.1	7402.9	7436.7	7436.7	7511.8	8339.0
VRC JUN30 RESERVOIR CONTENT, METERS	6/		436.44					
JUN30 ORC, M	7/		437.42					
BASE ECC, M	8/	438.36						
JUL 31 ORC, M			440.13	440.13	440.13	440.13	440.13	440.13

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/PRECEEDING LINE TIMES 1/.
3/ CUMMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS
4/ UPSTREAM DISCHARGE REQUIREMENT.
5/ MAXIMUM(FULL CONTENT (8757.8 HM^3) 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 4: 2005 Variable Refill Curve

Duncan Reservoir

		INITIAL	1-Jan	1-Feb	1-Mar	1-Apr	1-May	1-Jun
PROBABLE DATE 31JULY INFLOW,KAF			1717.7	1727.6	1652.3	1602.7	1386.1	954.1
& IN KSFD	**		866	871	833	808	698.8	481
95% FORECAST ERROR FOR DATE, IN KSFD			118.4	108.9	97.5	88.1	73.3	73.3
95% CONF.DATE-31JULY INFLOW, KSFD	1/		747.6	762.1	735.5	719.9	625.5	407.7
ASSUMED FEB1-JUL31 INFLOW, % OF VOL			100					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		747.6					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		100					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		233.2					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		191.4					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1827.8					
JAN31 ORC, FT	7/		1827.8					
BASE ECC, FT	8/	1856.3						
LOWER LIMIT, FT		1802.2						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		731.2	745.3				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		100	100				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		230.4	230.4				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		205	190.9				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1829.8	1827.7				
FEB28 ORC, FT	7/		1807.8	1807.8				
BASE ECC, FT	8/	1833.8						
LOWER LIMIT, FT		1795.3						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		712.5	726.2	716.4			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		100	100	100			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		227.3	227.3	227.3			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		220.6	206.9	216.7			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1832	1830	1831.4			
MAR31 ORC, FT	7/		1807.8	1807.8	1810.3			
BASE ECC, FT	8/	1828.2						
LOWER LIMIT, FT		1795.1						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.2	89.2	91.1	93.5		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		666.9	679.7	670	673.1		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		1800	1800	1800	1800		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		224.3	224.3	224.3	224.3		

VRC APR30 RESERVOIR CONTENT, KSFD	5/		263.2	250.4	260.1	257		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1837.9	1836.1	1837.5	1837.1		
APR30 ORC, FT	7/		1807.8	1807.8	1810.3	1810.7		
BASE ECC, FT	8/	1831.3						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		505.4	515.1	508.2	510.4	474.2	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		2000	2000	2000	2000	2000	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		168.5	168.5	168.5	168.5	168.5	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		368.9	359.2	366.1	363.9	400.1	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1851.8	1850.6	1851.7	1851.2	1855.8	
MAY31 ORC, FT	7/		1846.7	1846.7	1846.7	1846.7	1846.7	
BASE ECC, FT	8/	1846.5						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			31.7	31.7	32.4	33.3	35.6	46.9
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		237	241.6	238.2	239.7	222.7	191.2
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		3500	3500	3500	3500	3500	3500
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		108.5	108.5	108.5	108.5	108.5	108.5
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		577.3	572.7	576.1	574.6	591.6	623.1
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1877.3	1876.7	1877.2	1877	1878.9	1882.6
JUN30 ORC, FT	7/		1875.7	1875.7	1875.7	1875.7	1875.7	1875.7
BASE ECC, FT	8/	1875.7						
JUL 31 ECC, FT			1892	1892	1892	1892	1892	1892

** 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 4M: 2005 Variable Refill Curve

Duncan Reservoir

		INITIAL	1-Jan	1-Feb	1-Mar	1-Apr	1-May	1-Jun
PROBABLE DATE-31JULY INFLOW, KM^3			2.12	2.13	2.04	1.98	1.71	1.18
& IN HM^3	**		2118.8	2131.0	2038.0	1976.9	1709.7	1176.8
95% FORECAST ERROR FOR DATE, IN HM^3			289.7	266.4	238.5	215.5	179.3	179.3
95% CONF.DATE-31JULY INFLOW, HM^3	1/		1829.1	1864.6	1799.5	1761.3	1530.3	997.5
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		1829.1					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		2.83					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/		570.5					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		468.3					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		557.1					
JAN31 ORC, M	7/		557.1					
BASE ECC, M	8/	565.8						
LOWER LIMIT, M		549.3						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		1789.0	1823.5				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		2.83	2.83				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		563.7	563.7				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		501.6	467.1				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		557.7					
FEB28 ORC, M	7/		551.0					
BASE ECC, M	8/	558.9						
LOWER LIMIT, M		547.2						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		1743.2	1776.7	1752.7			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		2.83	2.83	2.83			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		556.1	556.1	556.1			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		539.7	506.2	530.2			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		558.4					
MAR31 ORC, M	7/		551.0					
BASE ECC, M	8/	557.2						
LOWER LIMIT, M		547.1						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.2	89.2	91.1	93.5		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		1631.6	1663.0	1639.2	1646.8		
MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		50.97	50.97	50.97	50.97		

MIN MAY1-JUL31 OUTFLOW, HM^3	4/		548.8	548.8	548.8	548.8		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		643.9	612.6	636.4	628.8		
VRC APR30 RESERVOIR CONTENT, METERS	6/		560.2					
APR30 ORC, M	7/		551.0					
BASE ECC, M	8/	558.2						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		1236.5	1260.2	1243.4	1248.7	1160.2	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		56.63	56.63	56.63	56.63	56.63	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		412.3	412.3	412.3	412.3	412.3	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		902.6	878.8	895.7	890.3	978.9	
VRC MAY31 RESERVOIR CONTENT, METERS	6/							
MAY31 ORC, M	7/							
BASE ECC, M	8/	562.8						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			31.7	31.7	32.4	33.3	35.6	46.9
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		579.8	591.1	582.8	586.5	544.9	467.8
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		99.11	99.11	99.11	99.11	99.11	99.11
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		265.5	265.5	265.5	265.5	265.5	265.5
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		1412.4	1401.2	1409.5	1405.8	1447.4	1524.5
VRC JUN30 RESERVOIR CONTENT, METERS	6/		572.2					
JUN30 ORC, M	7/		571.7					
BASE ECC, M	8/	571.7						
JUL 31 ORC, M			576.7	576.7	576.7	576.7	576.7	576.7

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (1726.8 HM^3) 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 5: 2005 Variable Refill Curve

Libby Reservoir

		INITIAL	1-Jan	1-Feb	1-Mar	1-Apr	1-May	1-Jun
PROBABLE DATE 31JULY INFLOW,KAF			5840	5805	5755	5774	5510	5156
PROBABLE DATE 31JULY INFLOW,KSFD			2944.3	2926.7	2901.5	2911.1	2778	2599.5
95% FORECAST ERROR FOR DATE, KSFD			637.8	478.5	447.7	433.6	392.2	376.6
OBSERVED JAN1-DATE INFLOW, IN KSFD			0	163.4	296.5	431.1	661.5	1388
95% CONF.DATE-31JULY INFLOW, KSFD	1/		2306.6	2284.9	2157.3	2046.4	1724.2	834.9
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		2235.3					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4000					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1337					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1612.2					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2416.8					
JAN31 ORC, FT	7/		2413.9					
BASE ECC, FT	9/	2413.9						
LOWER LIMIT, FT		2371.2						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		2170.7	2218.9				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1225	1225				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1564.8	1516.6				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2414.3	2411.8				
FEB28 ORC, FT	7/		2411.1	2411.1				
BASE ECC, FT	9/	2411.1						
LOWER LIMIT, FT		2320.8						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.7	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		2090.9	2137.3	2077.9			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4000	4000	4000			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1101	1101	1101			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1520.6	1474.2	1533.6			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2412	2409.5	2412.6			
MAR31 ORC, FT	7/		2408.2	2408.2	2408.2			
BASE ECC, FT	9/	2408.2						
LOWER LIMIT, FT		2288.5						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.4	85	87.6	93.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		1901.1	1943.1	1889.4	1919.3		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		10000	10000	10000	10000		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		981	981	981	981		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1590.4	1548.4	1602.1	1572.2		

VRC APR30 RESERVOIR CONTENT, FEET	6/		2415.7	2413.4	2416.3	2414.7		
APR30 ORC, FT	7/		2399.5	2399.5	2399.5	2399.5		
BASE ECC, FT	9/	2399.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.7	57.4	59.2	63.4	67.5	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		1284.1	1312.4	1276.1	1296.4	1164.6	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		11000	11000	11000	11000	1000	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		671	671	671	671	671	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		1897.4	1869.1	1905.4	1885.1	2016.9	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2431.2	2429.9	2431.6	2430.6	2436.9	
MAY31 ORC, FT	7/		2424.2	2424.2	2424.2	2424.2	2424.2	
BASE ECC, FT	9/	2424.2						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			20.3	20.9	21.6	23.1	24.6	36.45
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		468	478.5	465.1	472.5	424.5	304.3
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		11000	11000	11000	11000	1000	11000
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		341	341	341	341	341	341
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2383.5	2373	2386.4	2379	2427	2510.5
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2453.5	2453	2453.6	2453.3	2455.4	2459
JUN30 ORC, FT	7/		2453.5	2453	2453.6	2453.3	2458.5	2459
BASE ECC, FT	9/	2459						
JUL 31 ORC, FT			2459	2459	2459	2459	2459	2459
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		85.6	82.4	70.7	73.8	80.2	79.8

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

Table 5M: 2005 Variable Refill Curve

Libby Reservoir

		INIT IAL	1-Jan	1-Feb	1-Mar	1-Apr	1-May	1-Jun
PROBABLE DATE-31JULY INFLOW, KM^3			7.20	7.16	7.10	7.12	6.80	6.36
PROBABLE DATE-31JULY INFLOW, HM^3			7203.5	7160.5	7098.8	7122.3	6796.7	6359.9
95% FORECAST ERROR FOR DATE, HM^3			1560.4	1170.7	1095.3	1060.8	959.6	921.4
OBSERVED JAN1-DATE INFLOW, IN HM^3			0.0	399.8	725.4	1054.7	1618.4	3395.9
95% CONF.DATE-31JULY INFLOW, HM^3	1/		5643.3	5590.2	5278.1	5006.7	4218.4	2042.7
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		5468.9					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.27					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/		3271.1					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		3944.4					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		736.6					
JAN31 ORC, M	7/		735.8					
BASE ECC, M	9/	735.8						
LOWER LIMIT, M		722.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		5310.8	5428.8				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.27	113.27				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		2997.1	2997.1				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		3828.4	3710.5				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		735.9	735.1				
FEB28 ORC, M	7/		734.9	734.9				
BASE ECC, M	9/	734.9						
LOWER LIMIT, M		707.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.7	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		5115.6	5229.1	5083.8			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.27	113.27	113.27			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		2693.7	2693.7	2693.7			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		3720.3	3606.8	3752.1			
VRC Mar31 Reservoir Content Meters	6/		735.2	734.4	735.4			
MAR31 ORC, M	7/		734.0	734.0	734.0			
BASE ECC, M	9/	734.0						
LOWER LIMIT, M		697.5						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.4	85	87.6	93.8		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		4651.2	4754.0	4622.6	4695.8		
MAY MINIMUM FLOW REQUIREMENT, m^3/S	3/		283.17	283.17	283.17	283.17		

MIN MAY1-JUL31 OUTFLOW, HM^3	4/		2400.1	2400.1	2400.1	2400.1		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		3891.1	3788.3	3919.7	3846.5		
VRC APR30 RESERVOIR CONTENT, METERS	6/		736.3	735.6	736.5	736.0		
APR30 ORC, M	7/		731.4	731.4	731.4	731.4		
BASE ECC, M	9/	731.4						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.7	57.4	59.2	63.4	67.5	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		3141.7	3210.9	3122.1	3171.8	2849.3	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		311.49	311.49	311.49	311.49	28.32	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		1641.7	1641.7	1641.7	1641.7	1641.7	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		4642.2	4572.9	4661.8	4612.1	4934.5	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		741.0	740.6	741.2	740.8	742.8	
MAY31 ORC, M	7/		738.9	738.9	738.9	738.9	738.9	
BASE ECC, M	9/	738.9						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			20.3	20.9	21.6	23.1	24.6	36.45
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		1145.0	1170.7	1137.9	1156.0	1038.6	744.5
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		311.49	311.49	311.49	311.49	28.32	311.49
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		834.3	834.3	834.3	834.3	834.3	834.3
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		5831.5	5805.8	5838.6	5820.5	5937.9	6142.2
VRC JUN30 RESERVOIR CONTENT, METERS	6/		747.8	747.7	747.9	747.8	748.4	749.5
JUN30 ORC, M	7/		747.8	747.7	747.9	747.8	749.4	749.5
BASE ECC, M	9/	749.5						
JUL 31 ORC, M			749.5	749.5	749.5	749.5	749.5	749.5
JAN1-JUL31 FORECAST,-EARLYBIRD, KM^3	8/		105.59	101.64	87.21	91.03	98.93	98.43

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 (6412.6 HM^3) 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
English Units
1-May 2005

1-May Forecast of May – August Unregulated Runoff Volume, Maf		52.081
Less Estimated Depletions, Maf		1.500
Less Upstream Storage Corrections, Maf		16.326
Mica	5.464	
Arrow	3.600	
Duncan	1.293	
Libby	1.703	
Libby + Duncan Under Draft	0	
Hungry Horse	0.312	
Flathead Lake	0.500	
Noxon Rapids	0	
Pend Oreille Lake	0.500	
Grand Coulee	2.535	
Brownlee	0.028	
Dworshak	0.141	
John Day	0.250	
Total	16.326	
Forecast of Adjusted Residual Runoff Volume, Maf		34.255
Computed Initial Controlled Flow from Chart 1 of the Flood Control Operating Plan, 1000-cfs		200

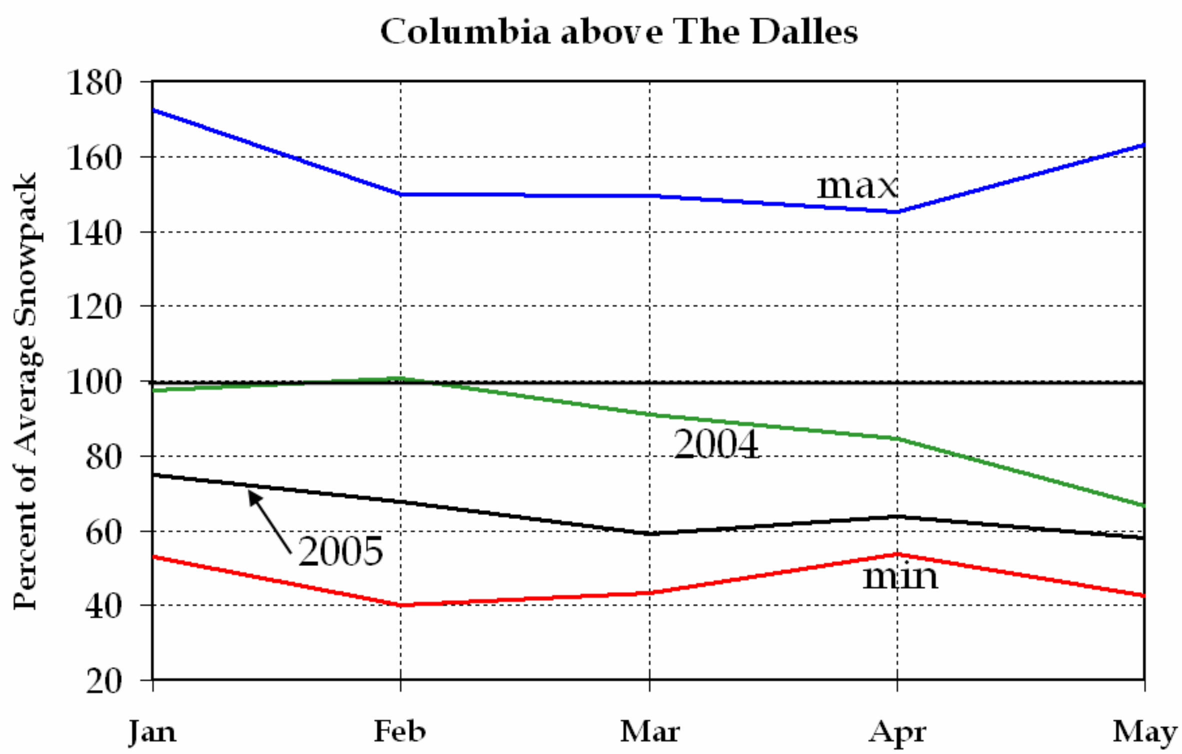
Table 6M: Computation of Initial Controlled Flow

Columbia River at The Dalles, OR
Metric Units
1-May 2005

1-May Forecast of May – August Unregulated Runoff Volume, km^3		64.241
Less Estimated Depletions, km^3		1.850
Less Upstream Storage Corrections, km^3		20.138
Mica	6.740	
Arrow	4.441	
Duncan	1.595	
Libby	2.101	
Libby + Duncan Under Draft	0	
Hungry Horse	0.385	
Flathead Lake	0.617	
Noxon Rapids	0	
Pend Oreille Lake	0.617	
Grand Coulee	3.127	
Brownlee	0.035	
Dworshak	0.174	
John Day	0.308	
Total	20.138	
Forecast of Adjusted Residual Runoff Volume, km^3		42.253
Computed Initial Controlled Flow from Chart 1 of the Flood Control Operating Plan, m^3/s		5,663.369

CHARTS

Chart 1: Columbia Basin Snowpack



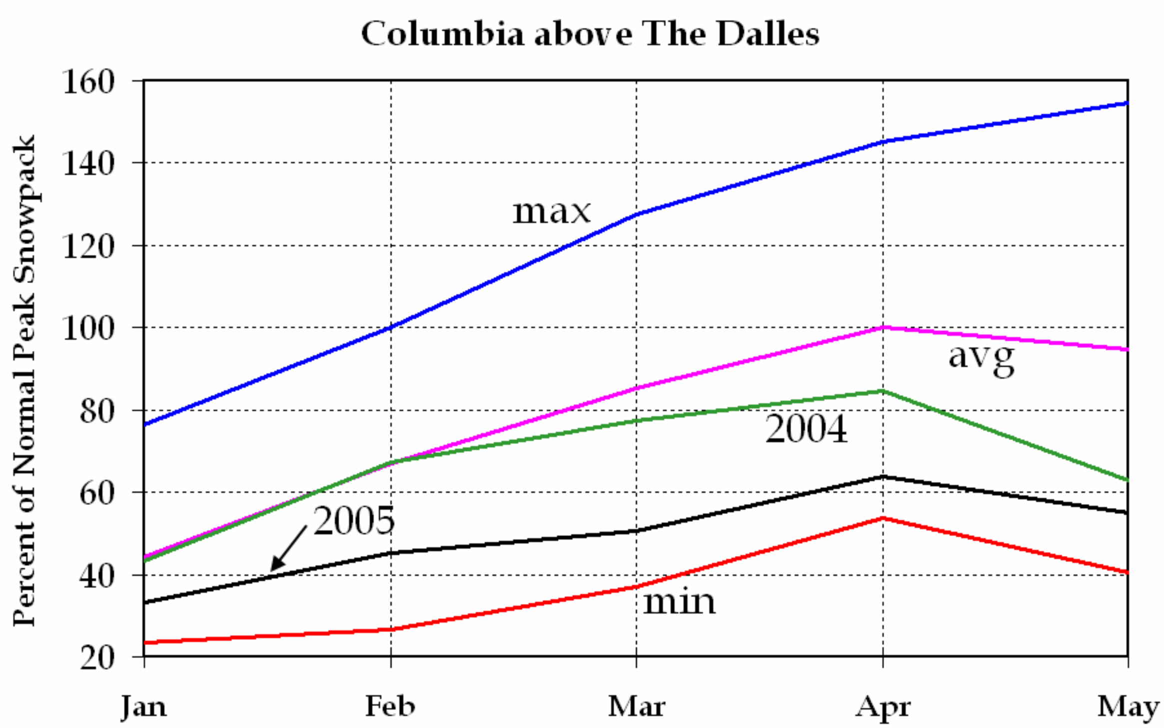


Chart 2: Seasonal Precipitation

Columbia River Basin
October 2004 – September 2005

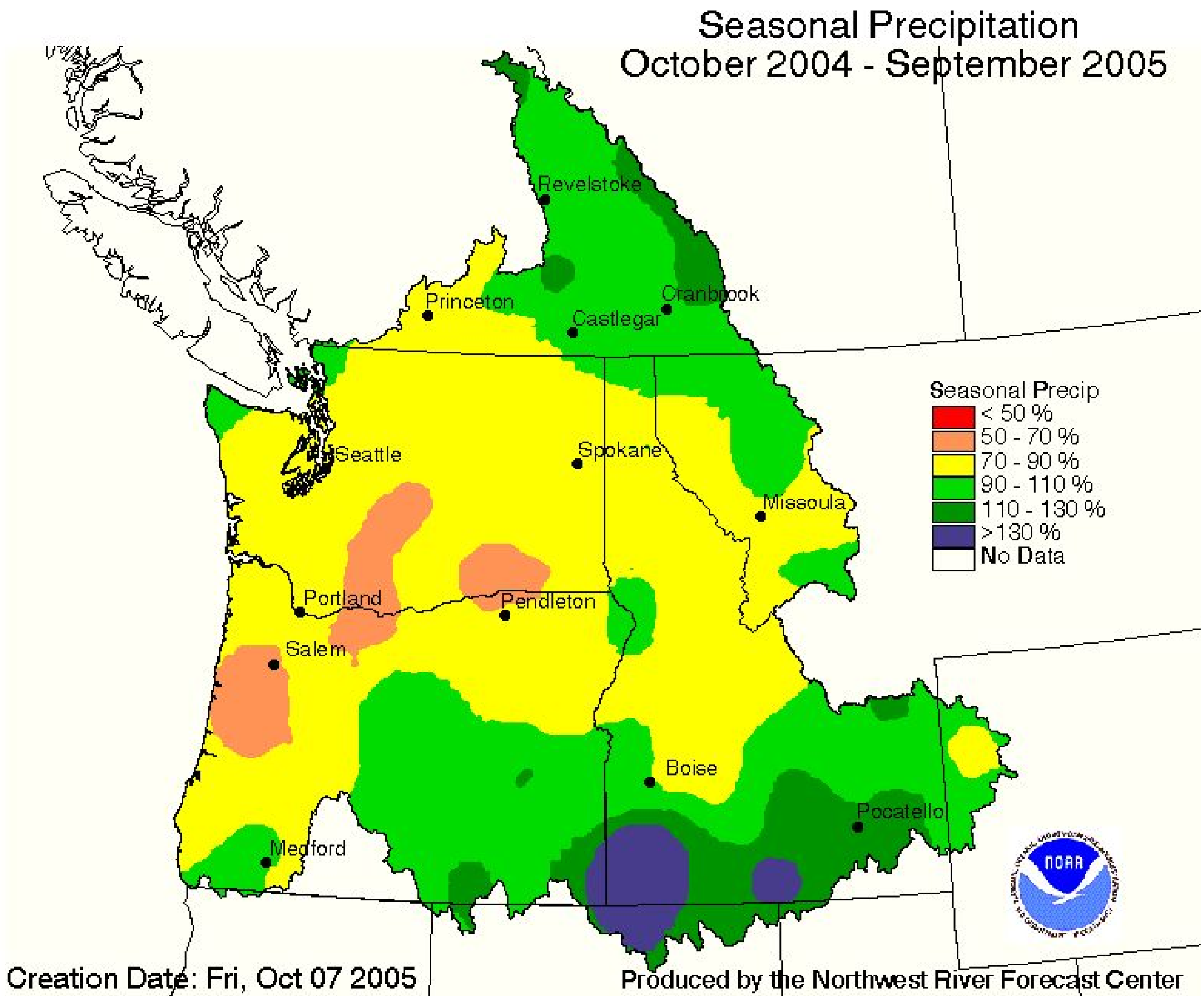


Chart 3: Accumulated Precipitation for WY 2005

At Primary Columbia River Basins

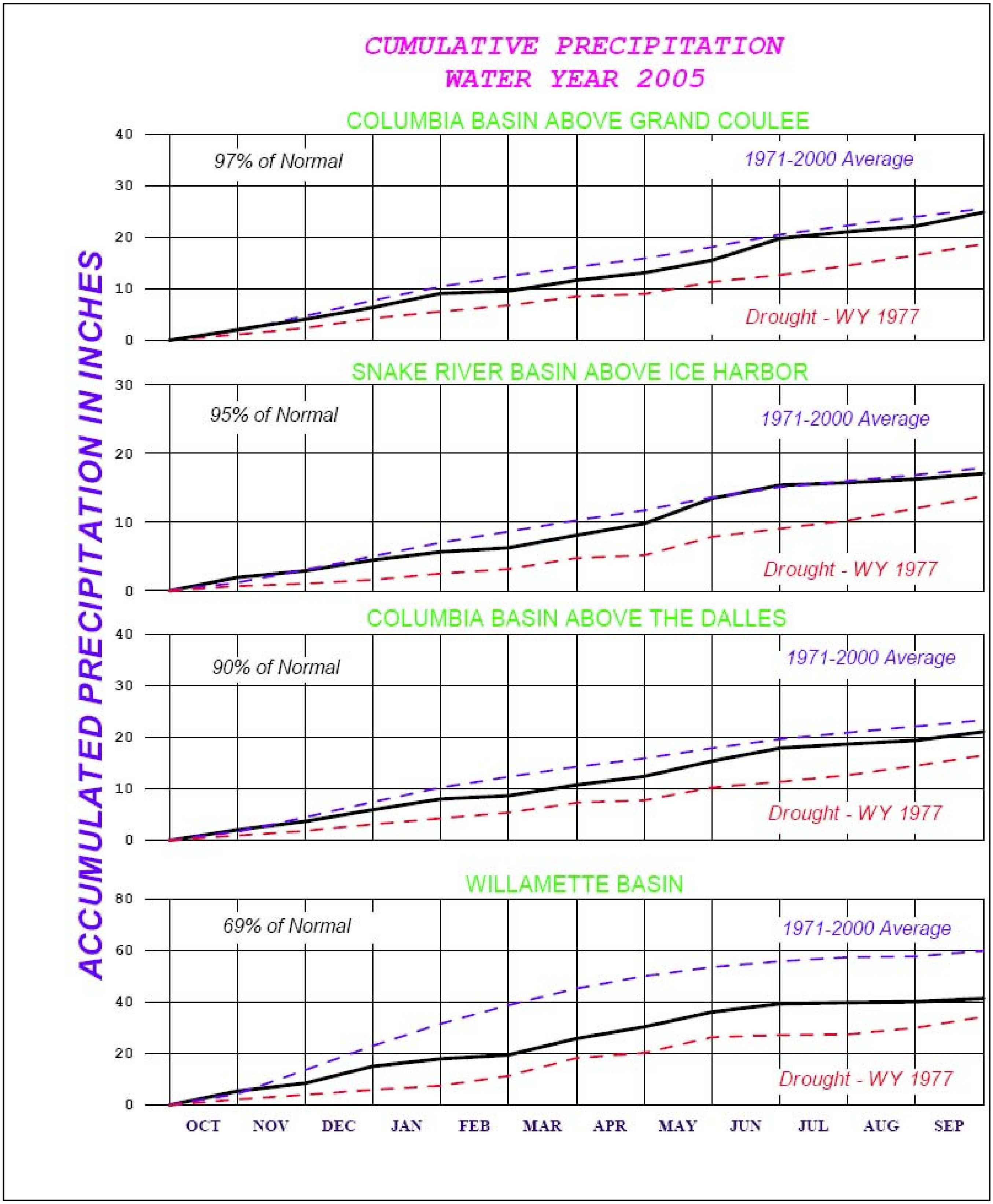
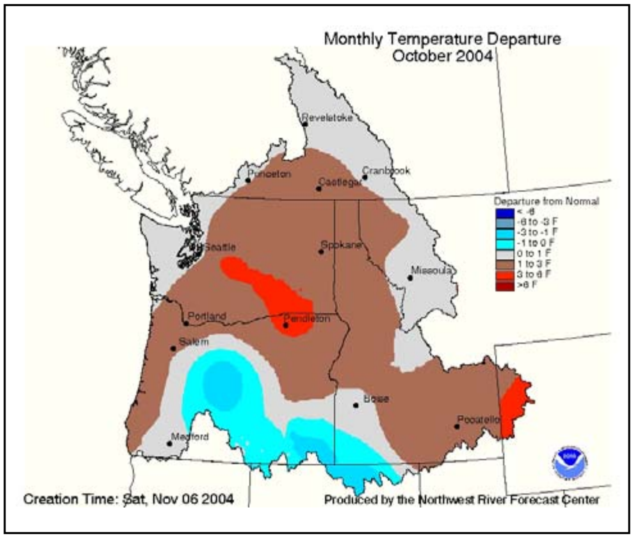
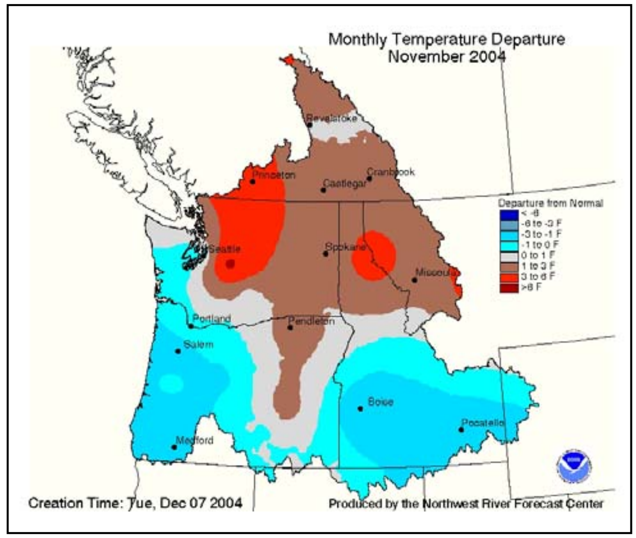
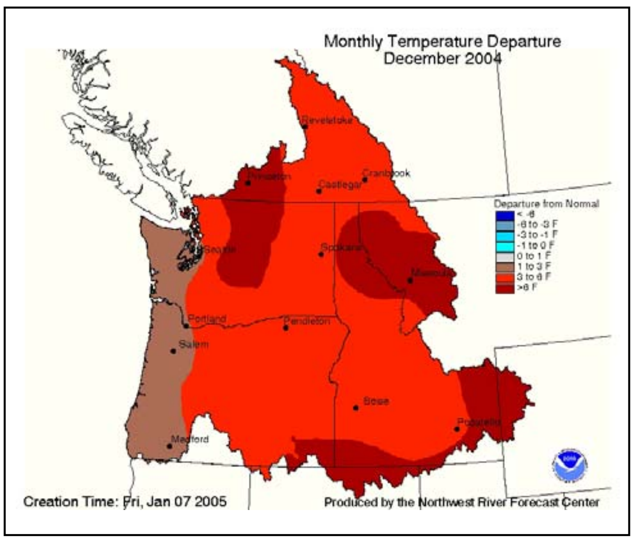
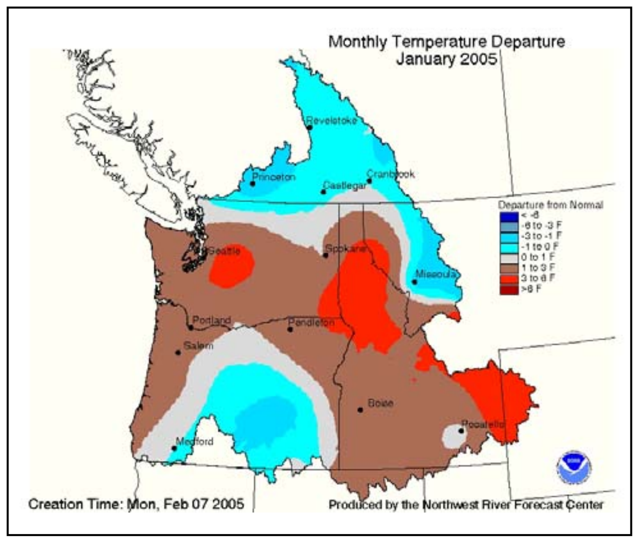


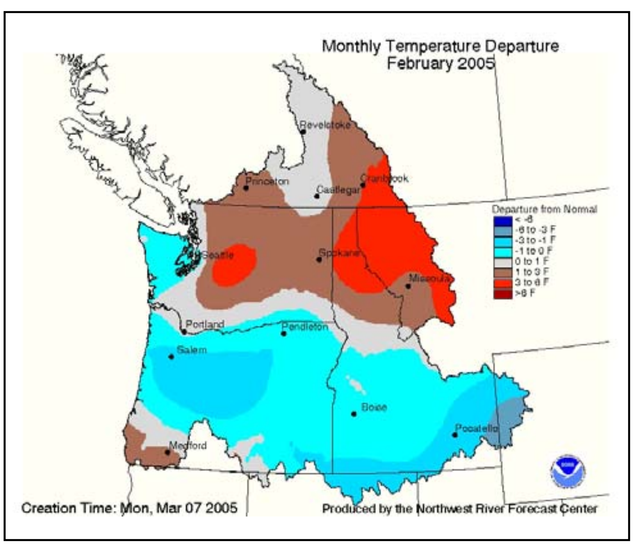
Chart 4: Pacific Northwest Monthly Temperature Departures From Normal October 2004 – March 2005











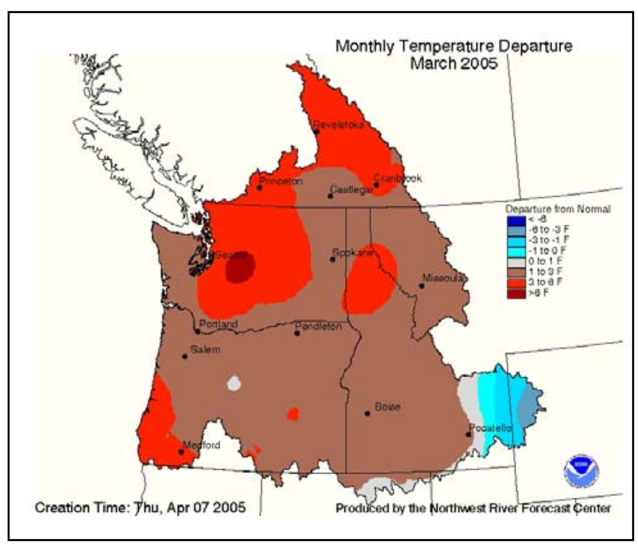
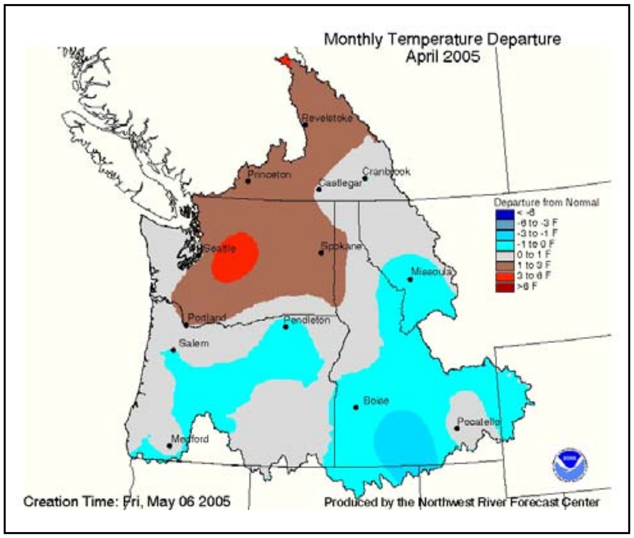
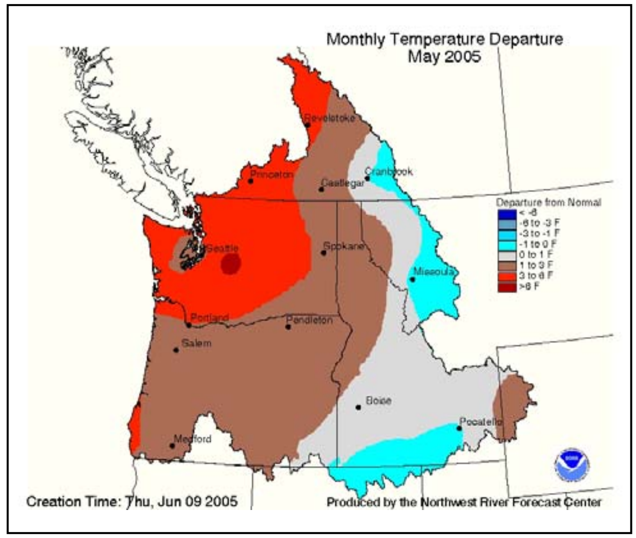
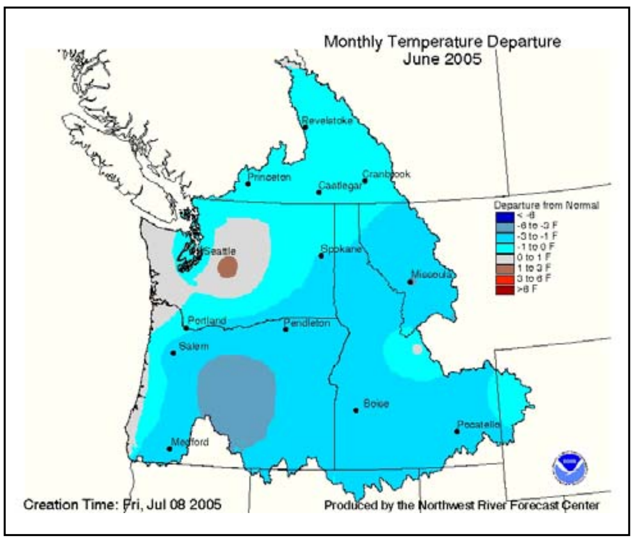


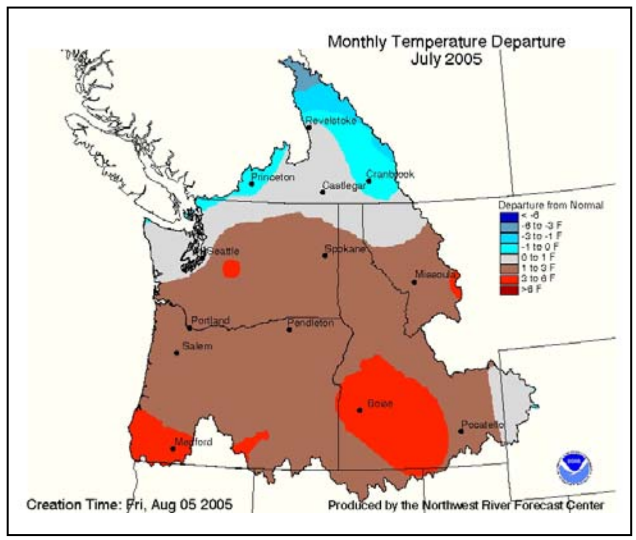
Chart 4 Continued: Pacific Northwest Monthly Temperature

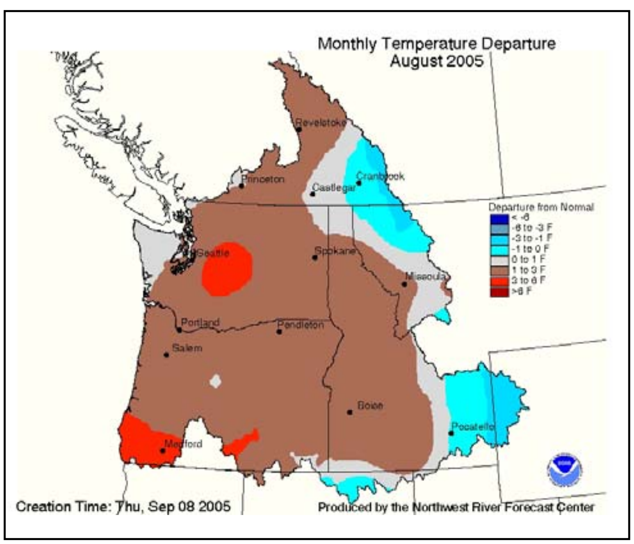
Departures From Normal April 2005 – September 2005











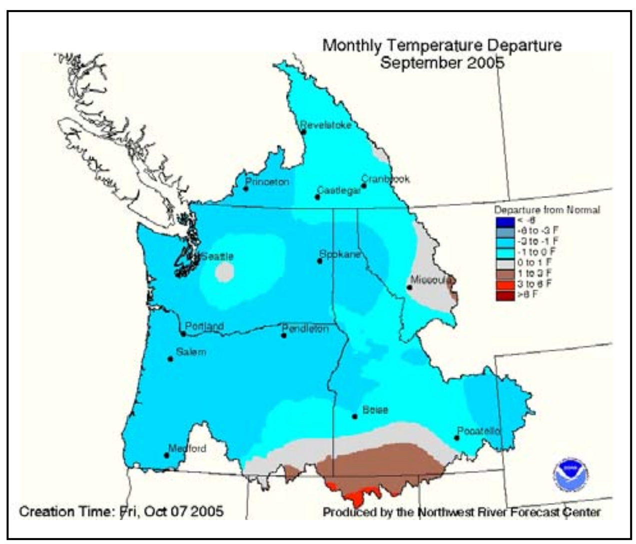
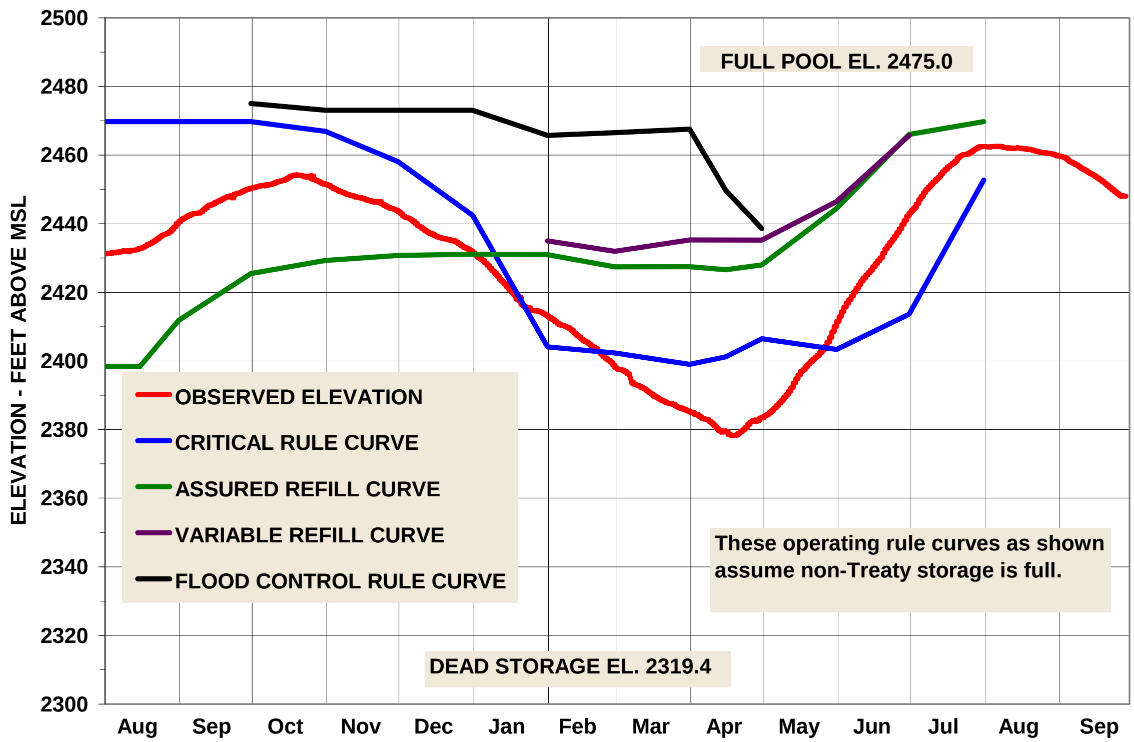


Chart 5: Regulation of Mica

1 August 2004 – September 2005



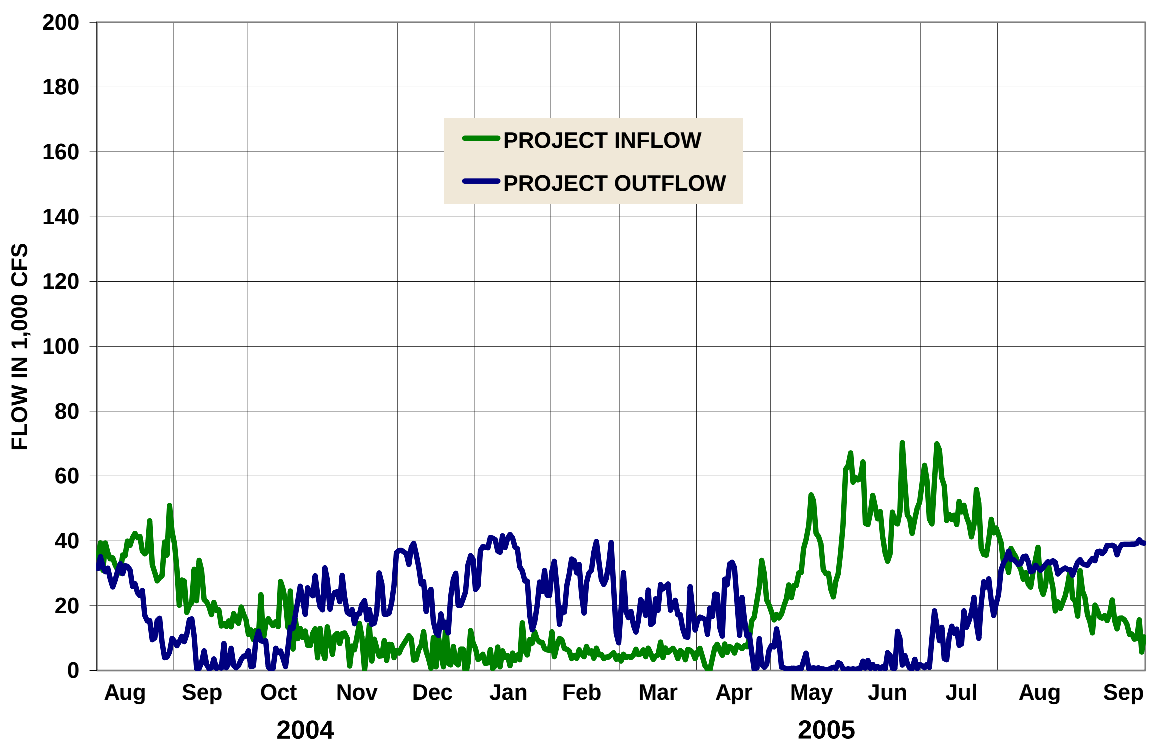
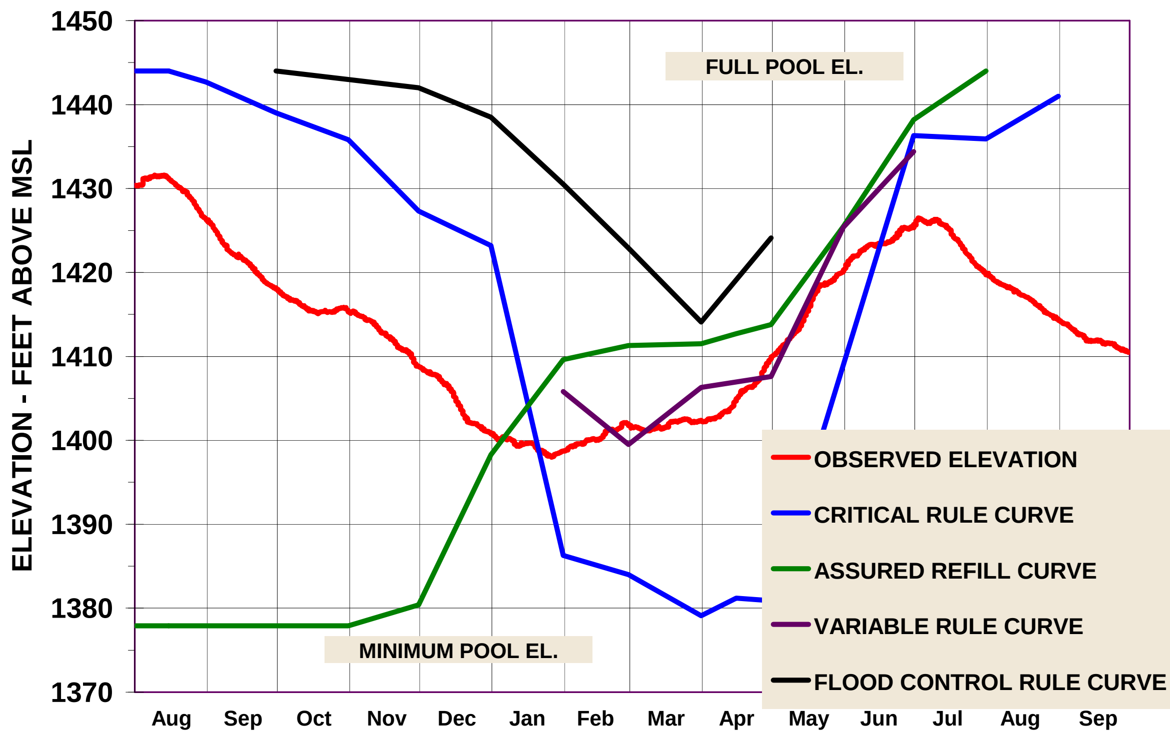


Chart 6: Regulation of Arrow

1 August 2004 – September 2005



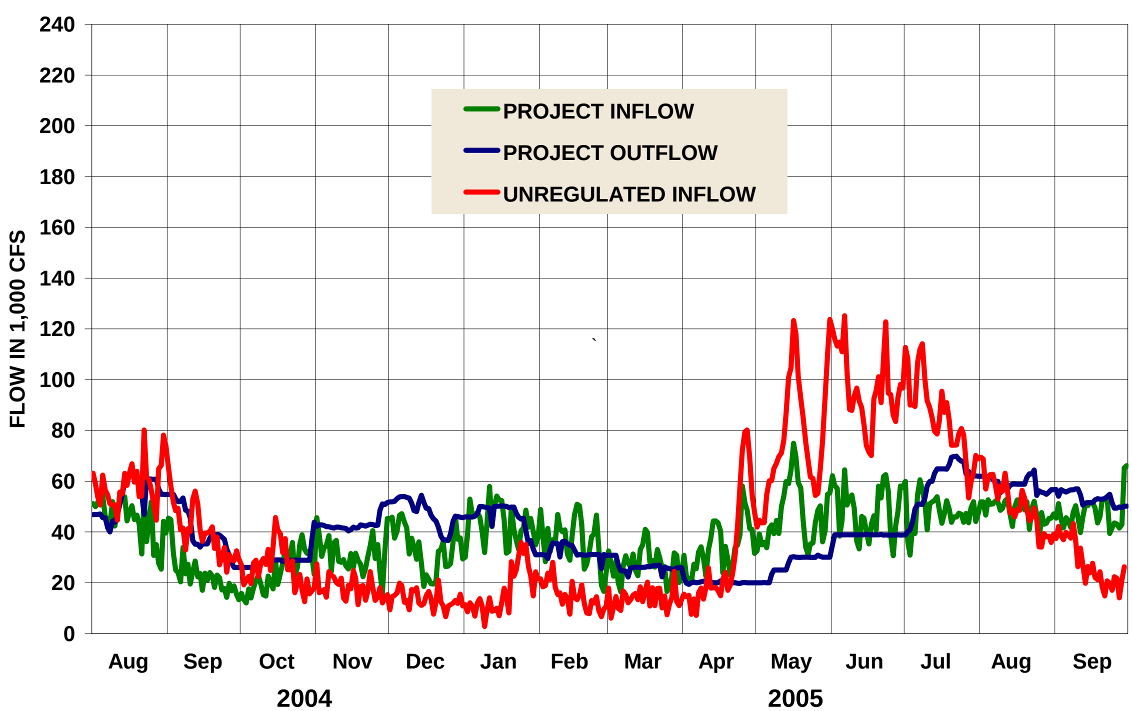
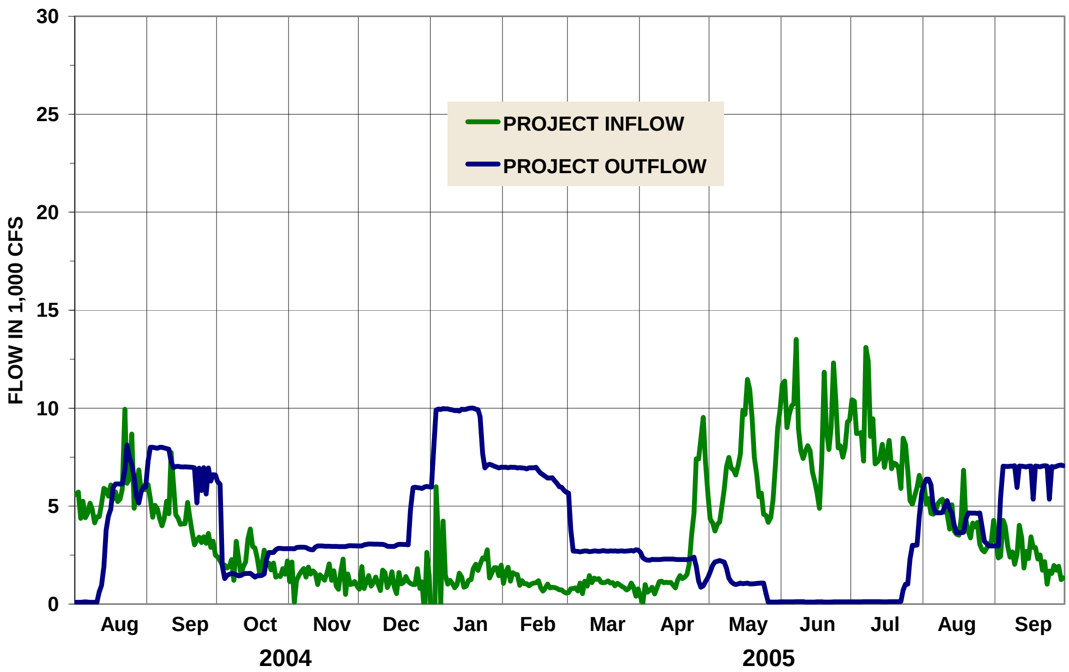


Chart 7: Regulation of Duncan

1 August 2004 – September 2005



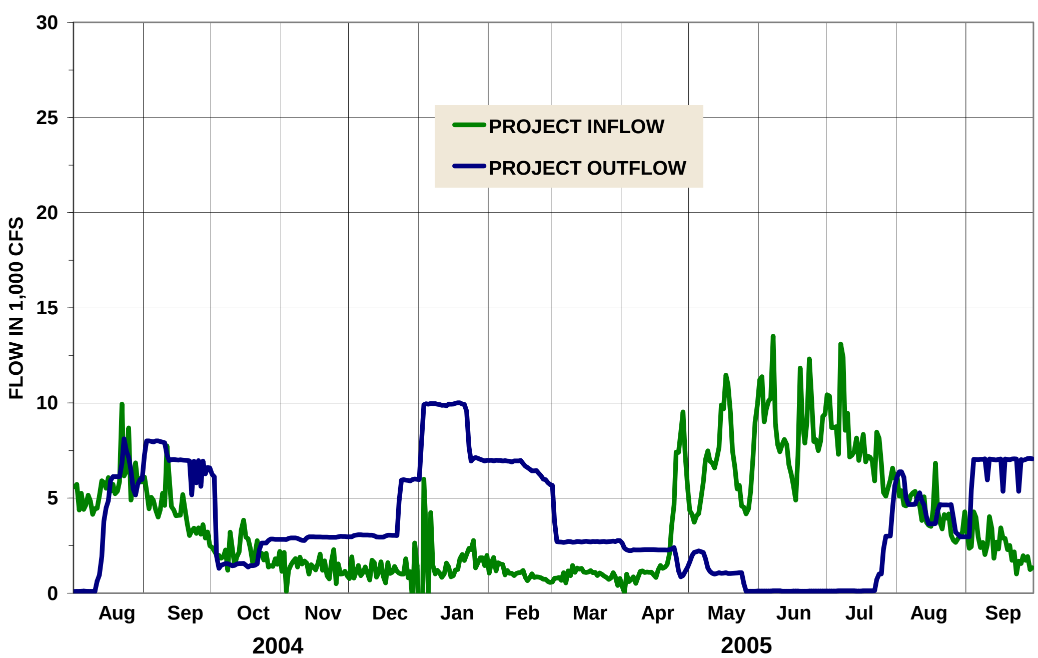
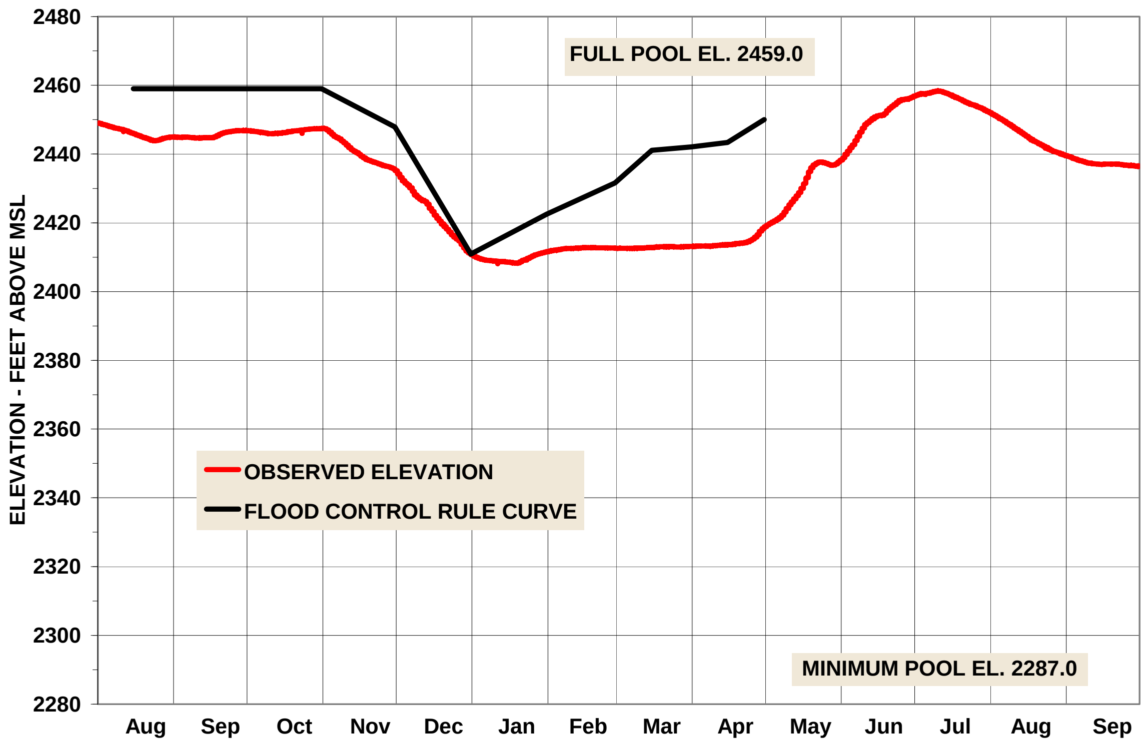


Chart 8: Regulation of Libby

1 August 2004 – September 2005



PROJECT INFLOW
PROJECT OUTFLOW
FLOW IN 1,000 CFS
0
10
20
30
40
50
60
70
80
90
Aug
Sep
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
2004
2005

Chart 9: Regulation of Kootenay Lake
1 August 2004 – September 2005

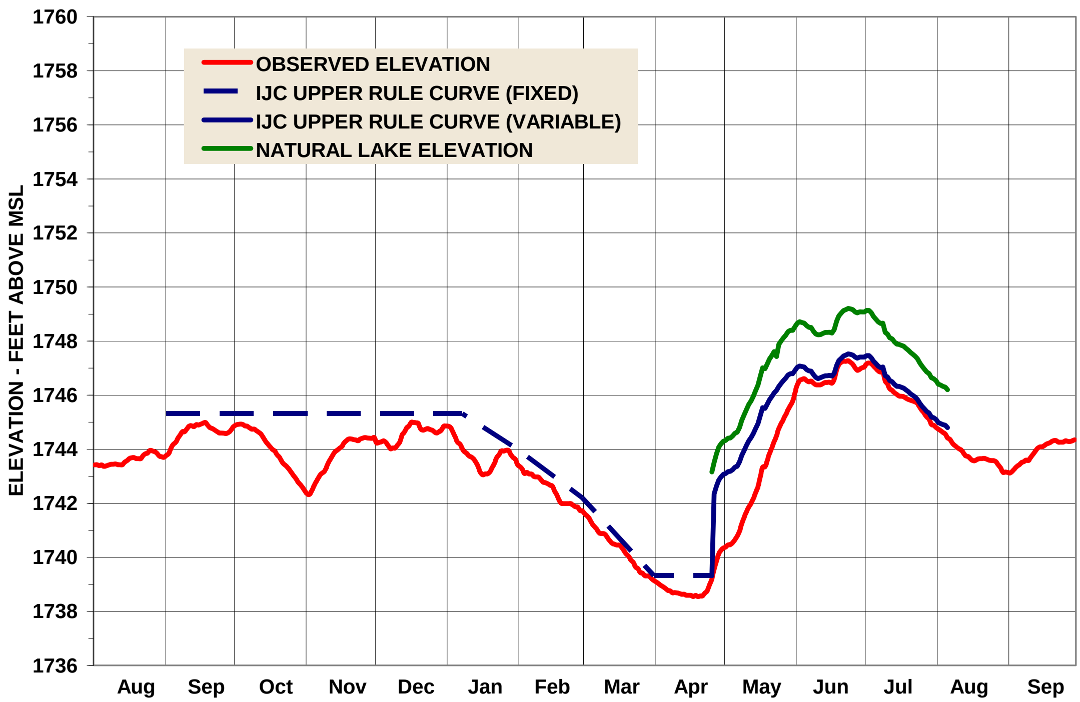


Chart 10: Columbia River At Birchbank

1 August 2004 – September 2005

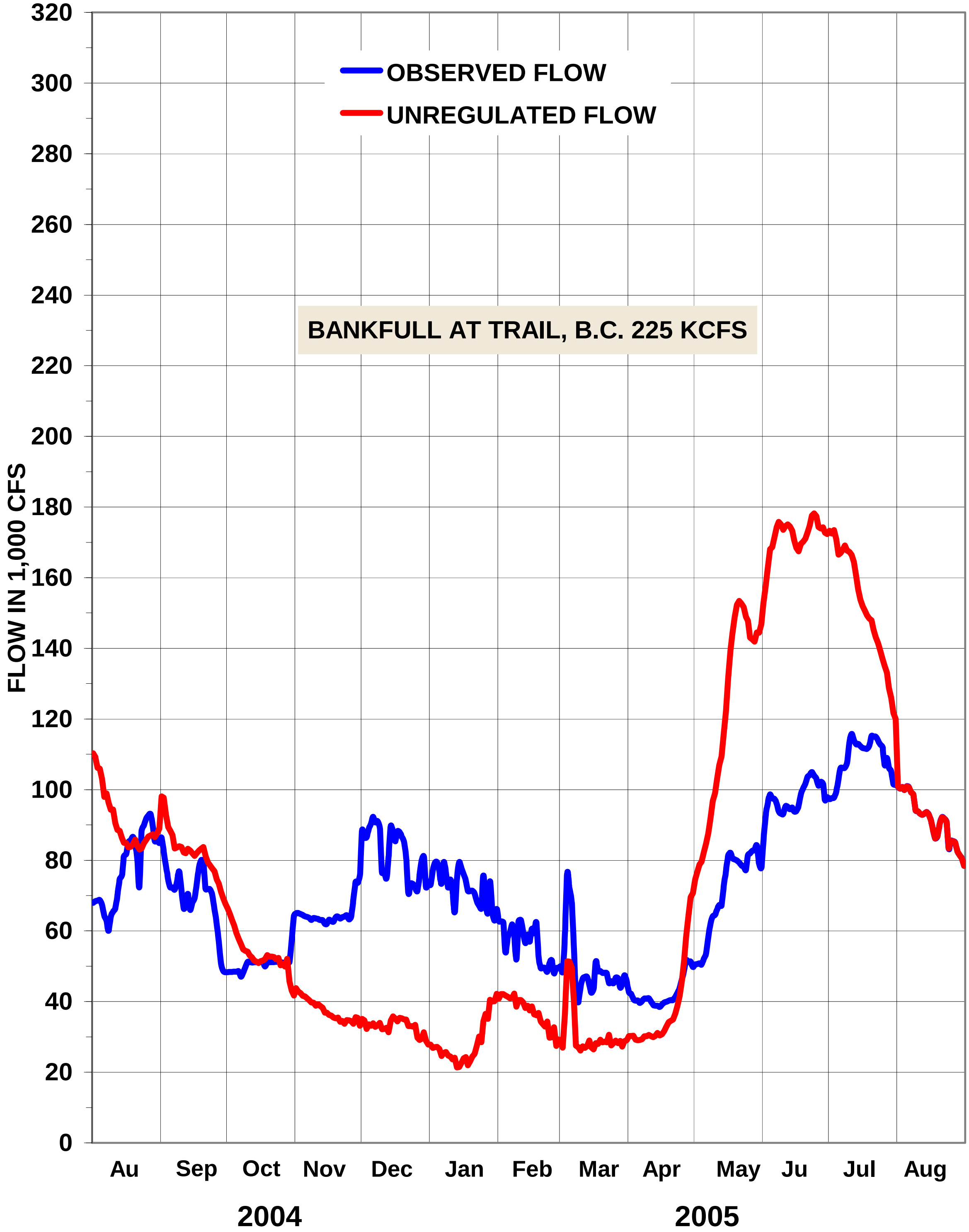
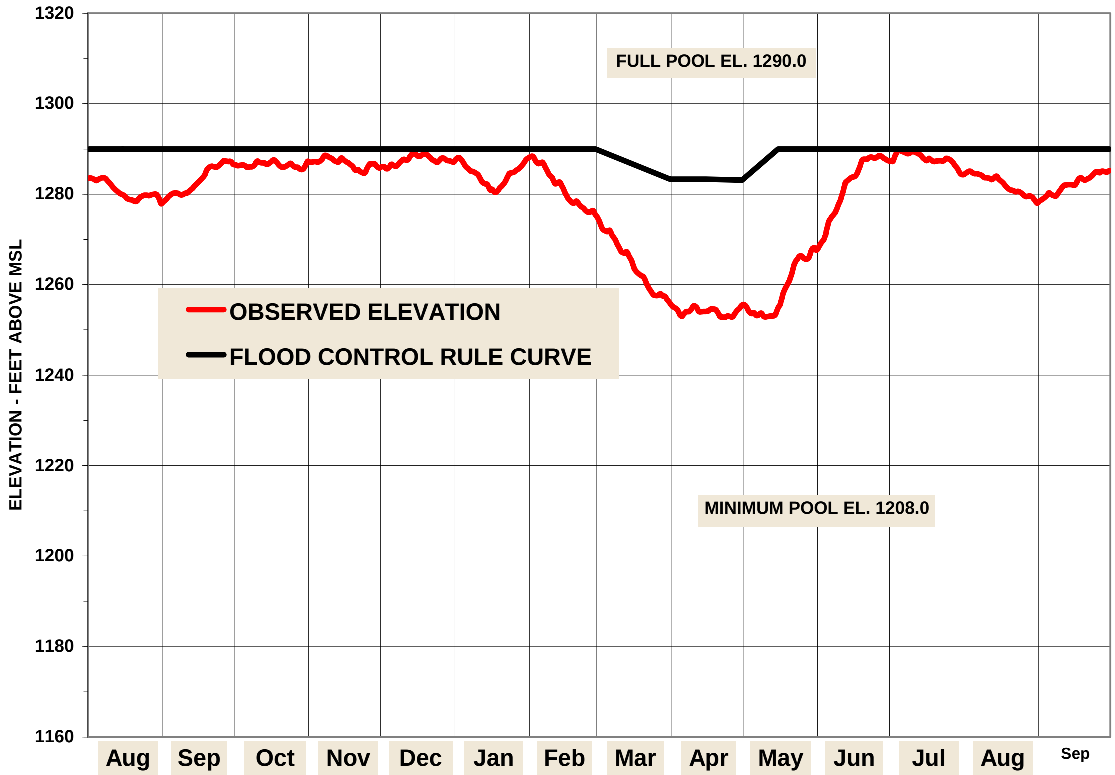


Chart 11: Regulation Of Grand Coulee

1 August 2004 – September 2005



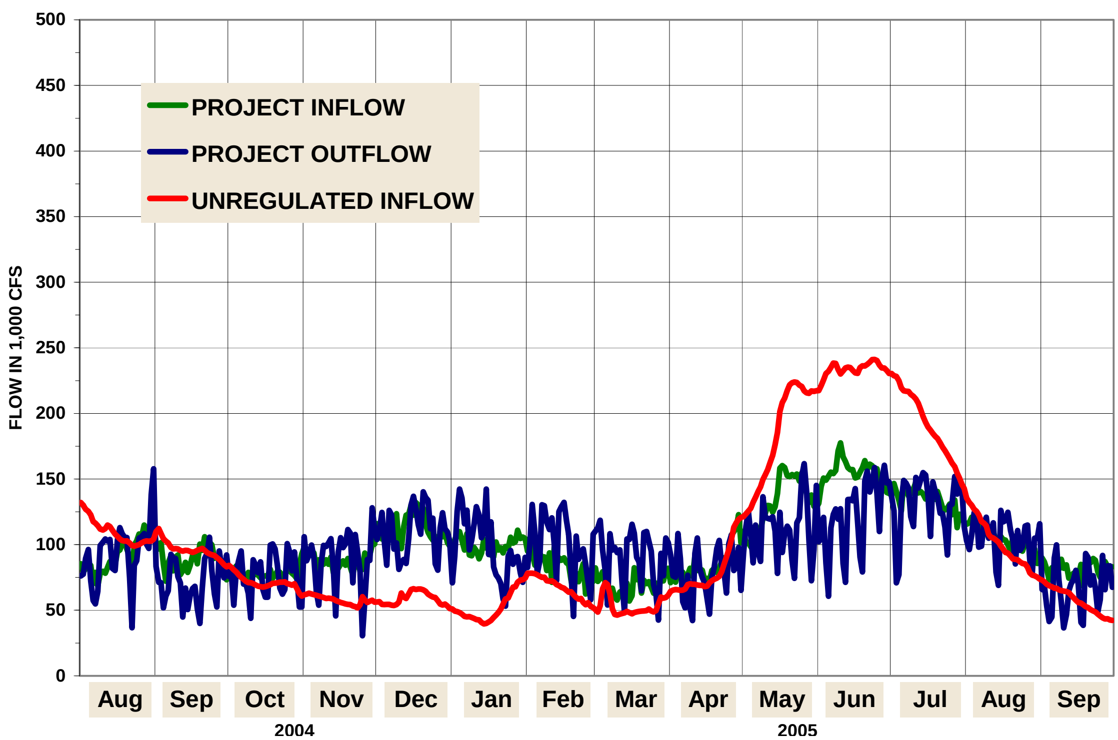


Chart 12: Columbia River At The Dalles

(Summary Hydrograph)
1 August 2004 – 30 September 2004)

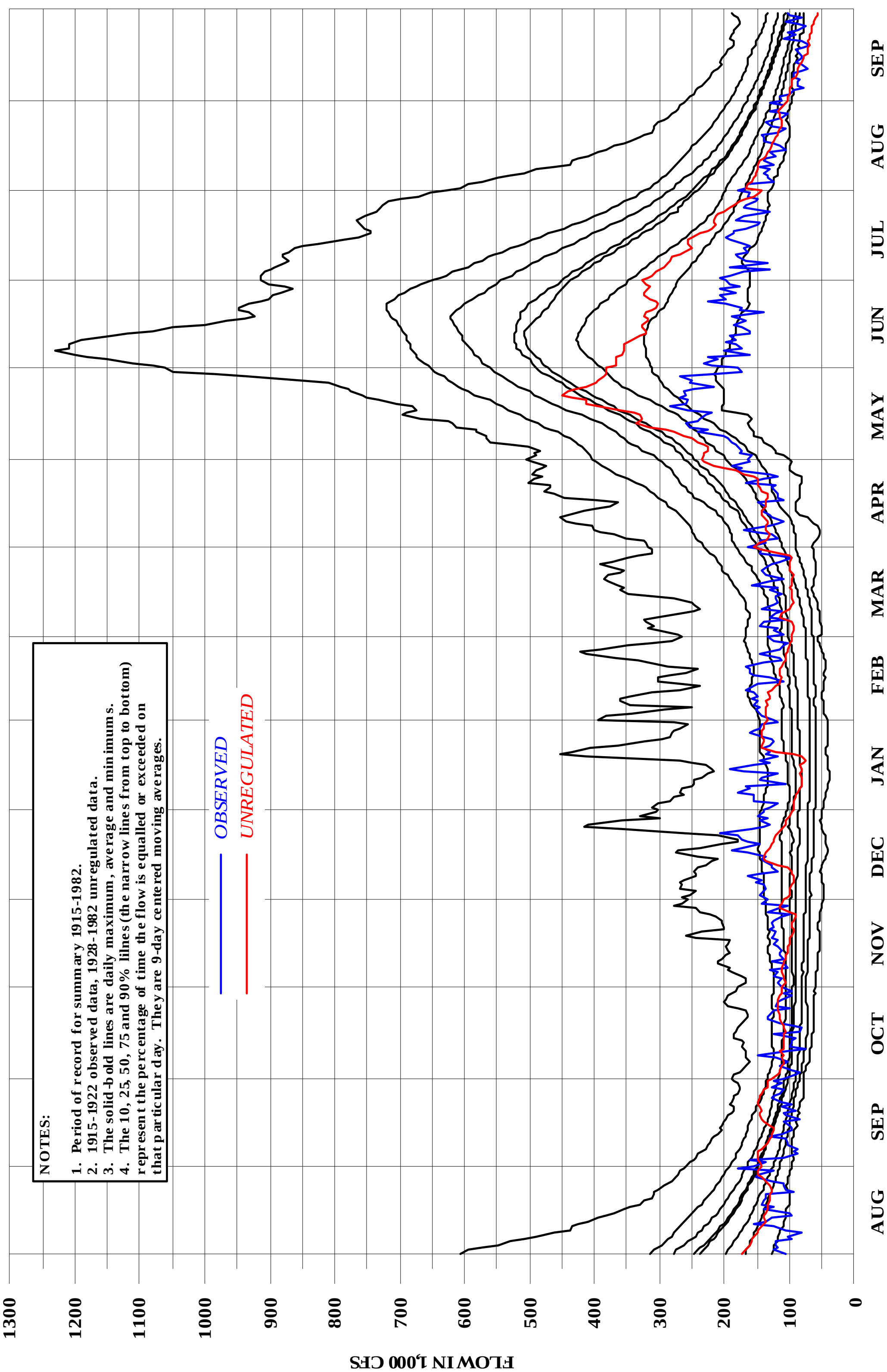


Chart 13: Columbia River at The Dalles

(Re-Regulation Plot)
1 April 2005 – 31 July 2005

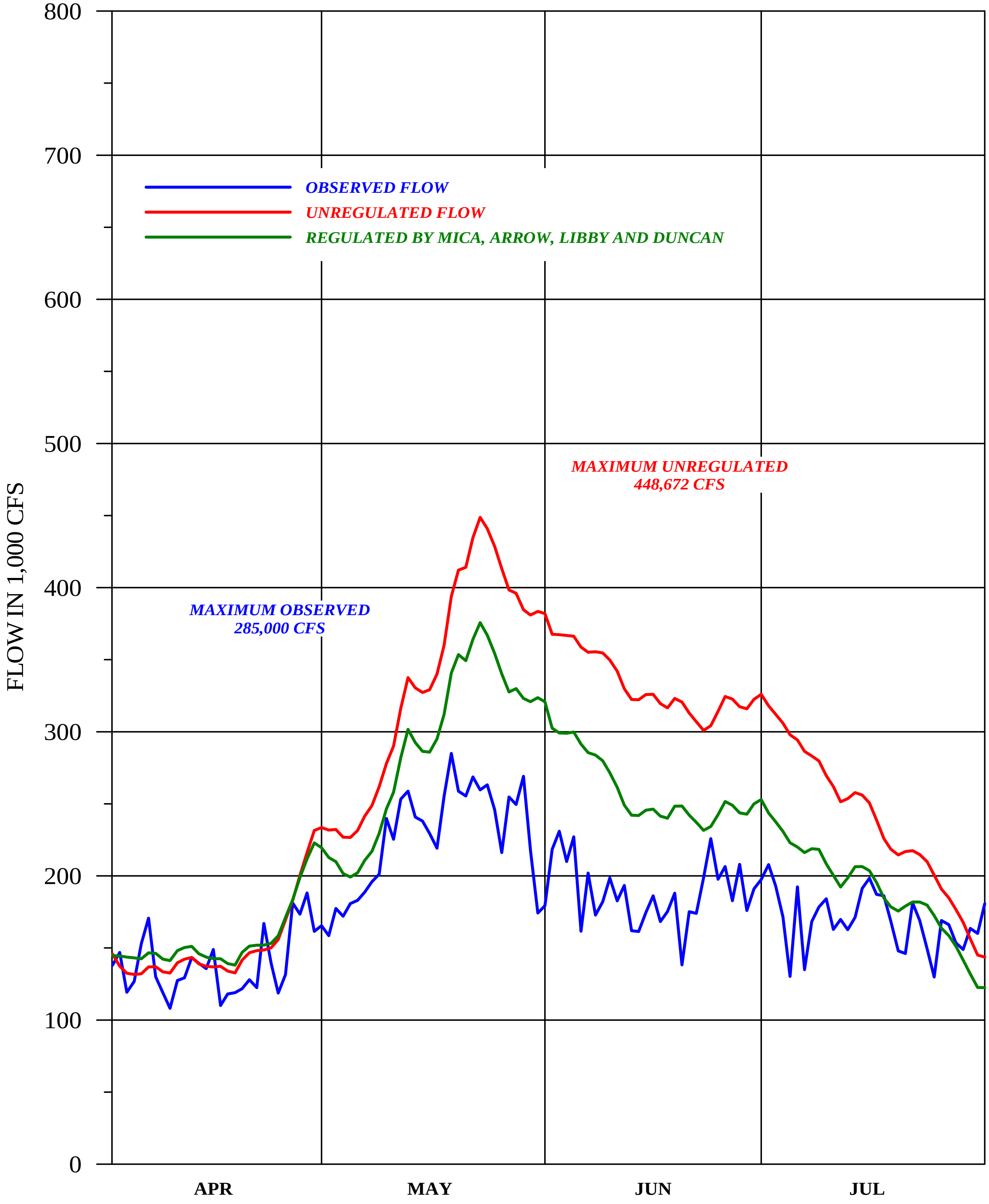


Chart 14: 2005 Relative Filling

Arrow and Grand Coulee