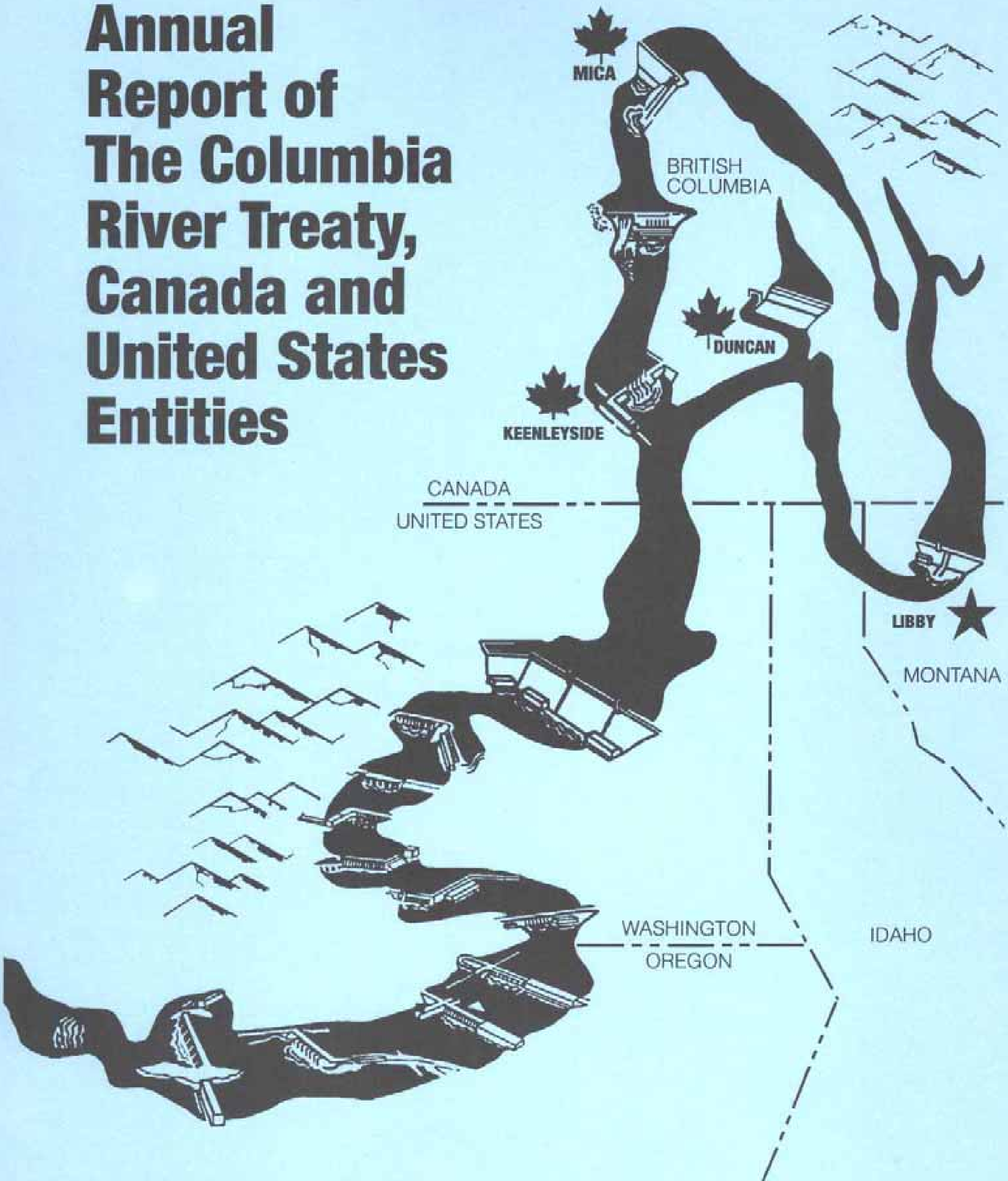
Annual Report of The Columbia River Treaty, Canada and United States Entities



1 October 2002 through
30 September 2003

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

FOR THE PERIOD 1 OCTOBER 2002 – 30 SEPTEMBER 2003

EXECUTIVE SUMMARY

General

The Canadian Treaty projects, Mica, Duncan, and Arrow were operated during the reporting period according to the 2002-2003 and 2003-2004 Detailed Operating Plans (DOP), the 2000 and 2003 Flood Control Operating Plans (FCOP), and several supplemental operating agreements described below. Throughout the year, Libby was operated according to the 2000 and 2003 FCOPs and the Libby Coordination Agreement (LCA) dated February 2000. Through December 2002, Libby was operated for power purposes according to the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER). Libby was also operated according to guidelines set forth in the U.S. Fish and Wildlife Service (USFWS) and the U.S. National Marine Fisheries Service (NMFS) 2000 Biological Opinions (BiOps).

Entity Agreements

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

- U.S. Entity Approval Relating to Amendatory Agreement #1 to the 1997 Pacific Northwest Coordination Agreement, signed 13 June 2003.
- Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for 1 August 2003 through 31 July 2004, signed 7 July 2003.

Operating Committee Agreements

Agreements approved by the Operating Committee include:

- Columbia River Treaty Operating Committee Agreement on the Operation of Canadian Treaty and Libby Storage Reservoirs and Exchanges of Power for the Period 8 August 2002 through 28 February 2003, signed 30 August 2002.
- Columbia River Treaty Operating Committee Agreement on the Operation of Duncan and Kootenay Lake Reservoirs for the Period 18 November 2002 through 20 March 2003, signed 20 November 2002.
- Columbia River Treaty Operating Committee Agreement on the Operation of Arrow and Grand Coulee Storage Reservoirs for the Period 10 December 2002 through 19 January 2003, signed 23 December 2002.

- Columbia River Treaty Operating Committee Agreement on the Operation of Canadian Treaty Storage for the Period 1 January 2003 through 31 July 2003, signed 10 February 2003.
- Columbia River Treaty Operating Committee Agreement on Implementation Procedures for Flood Control Reallocation for the 2003-2004 Operating Year, signed 16 July 2003.

In addition to the Operating Committee agreements listed here, the Bonneville Power Administration (BPA) and British Columbia Hydro and Power Authority (B.C. Hydro) under their Non-Treaty Storage Agreement (NTSA) executed a standardized May-June storage/July-August release agreement to benefit fisheries, and extended the expiry date of a Treaty Special Storage Agreement under the NTSA from 20 December 2002 to 20 March 2003.

System Operation

Under the 2002-2003 DOP, the Coordinated System operated similar to the Assured Operating Plan (AOP) except for flood control. The 2002-2003 AOP included a flood control allocation of 5.1 million acre-feet (Maf) in Arrow and 2.08 Maf in Mica. B.C. Hydro requested a reallocation of the flood control space and the United States (U.S.) agreed on 1 November 2002 to the request to operate to 3.6 Maf in Arrow and 4.08 Maf in Mica. The Canadian storage system began the operating year below its composite Operating Rule Curve (ORC) content and remained well below the ORC through the operating year and through the water year (WY) ending September 2003

The 1 January 2003 water supply forecast (WSF) for the Columbia River at The Dalles for January through July was 99.3 cubic kilometers (km^3) (80.5 Maf), or 75 percent of the 1971-2000 average. This was similar to the January final forecast in 2001, which was a drought year. Precipitation was much below normal through the fall and to the end of the calendar 2002 year. Only March and April of 2003 experienced more normal precipitation and increased streamflow. However this did not significantly influence the overall water supply. The unregulated runoff from January through July was 108.2 km^3 (87.7 Maf) at The Dalles, 82 percent of the 1971-2000 average. The unregulated runoff for 2003 peak unregulated flow at The Dalles was 16,772 cubic meters per second (m^3/s) (592,300 cubic feet per second (cfs)) on 1 June 2003 and a regulated peak flow of 10,944 m^3/s (386,500 cfs) occurred on 31 May 2003.

The Columbia River was operated to meet chum salmon needs below Bonneville Dam from 5 November 2002 through May 2003. U.S. reservoirs were operated to target the 10 April flood control elevation per the NMFS 2000 BiOp for juvenile fish needs. For 2003

Libby Dam conducted an operation that focused on the Kootenai River white sturgeon larvae in conjunction with standard sturgeon pulsing operation to enhance spawning. The U.S. storage projects refilled by 30 June 2003. Projects were then drafted to the NMFS 2000 BiOp draft limits for 31 August, except for Dworshak Dam, which 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 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 293.1 average megawatts (aMW) at rates up to 642 megawatts (MW) during 1 August 2002 through 31 March 2003; 534.5 aMW at rates up to 1171 MW during 1 April through 31 July 2003; and 537.3 aMW at rates up to 1176 MW during 1 August through 30 September 2003. No Entitlement power was disposed directly in the U.S. during 1 August 2002 through 30 September 2003, as was allowed by the 29 March 1999 Agreements on "Aspects of the Delivery of the Canadian Entitlement for April 1, 1998 through September 15, 2024" and "Disposals of the Canadian Entitlement within the U.S. for April 1, 1998 through September 15, 2024."

Up to 31 March 2003, the Canadian Entitlement resulting from the operation of Mica Reservoir was sold to Columbia Storage Power Exchange (CSPE), a consortium of 41 Pacific Northwest utilities, in accordance with the Canadian Entitlement Purchase Agreement (CEPA), dated 13 August 1964, through 2400 hours on 31 March 2003. Under the terms of the Canadian Entitlement Exchange Agreement (CEEA), also dated 13 August 1964, the U.S. Entity delivered capacity and energy to the CSPE participants based on the 1964 estimates of the Canadian Entitlement. Delivery under the CEEA was 93 aMW at rates up to 167 MW during 1 August 2002 through 31 March 2003. The CEPA and CEEA expired on 31 March 2003.

Treaty Project Operation

At the beginning of the 2002-2003 operating year, 31 July 2002, actual Canadian Treaty storage (Canadian storage) was at 17.4 km^3 (14.1 Maf) or 91.3 percent full. Canadian storage continued to refill marginally through August 2002 before beginning to draft in September, reaching 2.3 km^3 (1.9 Maf) on 31 March 2003. Canadian storage did not refill fully during the operating year, reaching 17.0 km^3 (13.7 Maf) or 88.7 percent full on 31 July 2003.

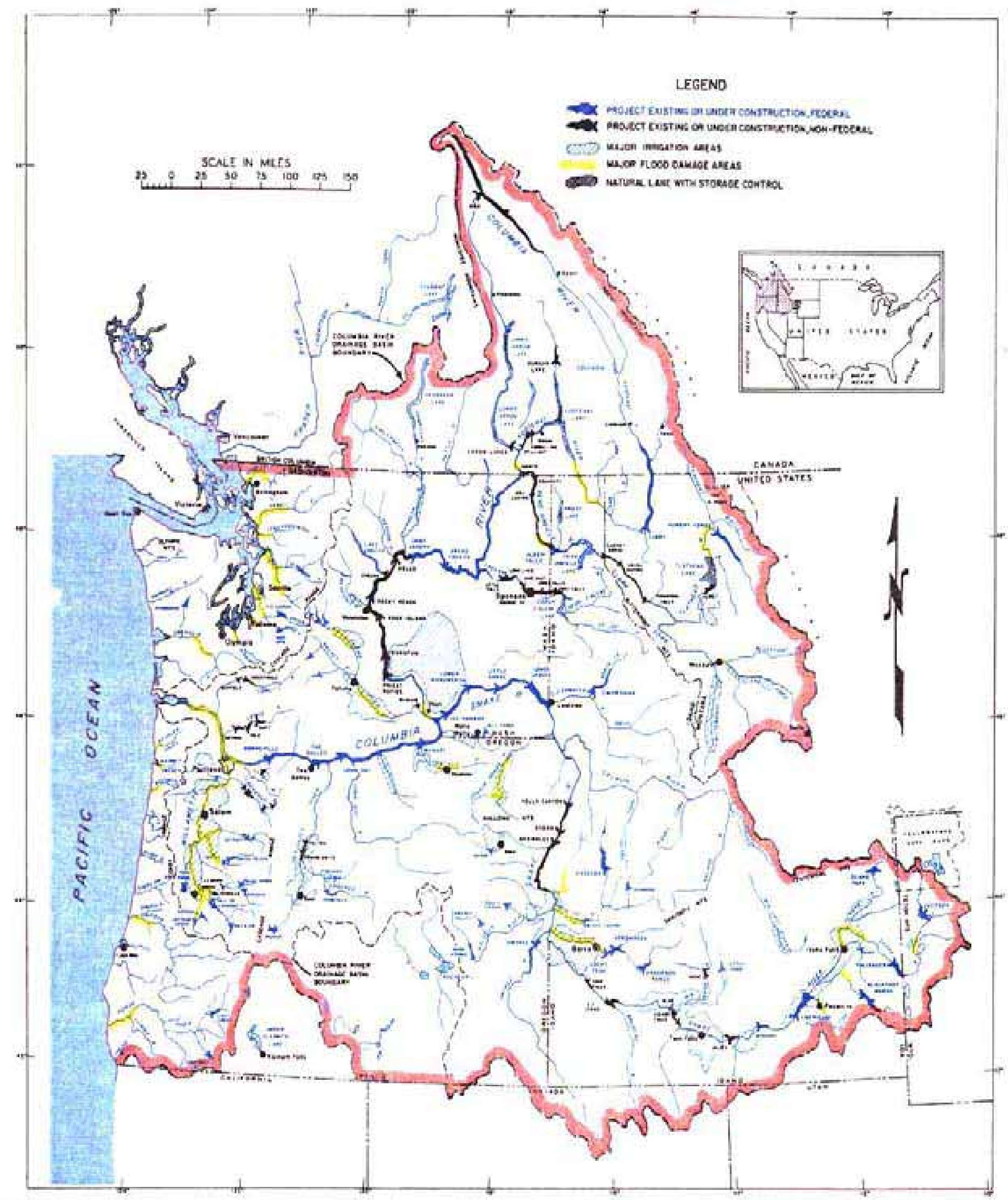
Mica (Kinbasket) Reservoir reached its maximum elevation of 751.37 meters (m) (2465.1 feet) on 3 September 2002, 3.02 m (9.9 feet) below full pool. The reservoir drafted rapidly during October through December, reaching 733.23 m (2,405.6 feet) by 31 December, 2.62 m (8.6 feet) above the historical minimum elevation for that date. The reservoir continued to draft January through March, reaching a minimum elevation of 714.09 m (2,342.8 feet), on 8 April 2003. With a low initial level and below normal seasonal inflows, the reservoir refill level during the operating year was much below normal, reaching a maximum elevation of 744.32 m (2442.0 feet), 10.1 m (33.0 feet) below full pool on 23 August 2003.

The Arrow Reservoir reached its maximum elevation of 439.92 m (1443.3 feet), 0.21 m (0.7 feet) below full pool on 17 July 2002. The coordinated hydro system was on proportional draft from August 2002 through January 2003. This contributed to the Arrow Reservoir being drafted to its minimum elevation much earlier than normal, reaching 424.68 m (1393.3 feet) by 3 February 2003. The reservoir refilled to a maximum elevation of 439.09 m (1440.6 feet) on 4 July 2003, 1.04 m (3.4 feet) below full pool. The operation of Arrow Reservoir was modified during the operating year under three Operating Committee Agreements to enhance whitefish and rainbow trout spawning and emergence downstream of the Arrow project in British Columbia and to provide additional power and non-power benefits in the United States.

Duncan Reservoir reached a maximum elevation of 576.78 m (1,892.3 feet) on 16 July 2003, 0.09 m (0.3 feet) above full pool. From September 2002 through December 2002, Duncan discharge was used to supplement inflow into Kootenay Lake. By mid-January 2003, the reservoir had drafted to minimum pool and was passing inflow. Reservoir discharge was reduced to the minimum of 3 m^3/s (100 cfs) on 11 May to initiate reservoir refill. The reservoir reached 576.38 m (1891.0 feet), 0.31 m (1.0 feet) below full pool on 1 August 2003.

Columbia Basin Map

COLUMBIA RIVER AND COASTAL BASINS



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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
NTSA	Non-Treaty Storage Agreement
ORC	Operating Rule Curve
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 is for the 2003 WY, 1 October 2002 through 30 September 2003. It includes information on the operation of Mica, Arrow, Duncan, and Libby Reservoirs during that period with additional information covering the reservoir system operating year, 1 August 2002 through 31 July 2003. The power and flood control effects downstream in Canada and the U.S. are described. This report is the thirty-seventh of a series of annual reports covering the period since the ratification of the 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 Treaty. The Canadian Entity is B.C. Hydro. 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 Treaty 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 the \$64.4 million (U.S.) for one half of the present worth of expected future flood control benefits in the U.S. 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 Treaty, for a payment of \$1.875 million (U.S.) for each of the first four requests for this "on-call" storage.

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 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.
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 Treaty.

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 13 March 2002 in Portland, OR. 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. Larry I. Bell, Chair Chair & Chief Executive Officer British Columbia Hydro and Power Authority Vancouver, British Columbia
Brigadier General William T. Grisoli, Member Division Engineer Northwestern Division U.S. Army Corps of Engineers Portland, Oregon	

BG Grisoli replaced BG David Fastabend as Member of the U.S. Entity on 8 July 2003.

The Entities have appointed Coordinators, Secretaries, and two joint standing committees to assist in Treaty implementation activities that are described in subsequent paragraphs. The primary duties and responsibilities of the Entities as specified in the Treaty and related documents are to:

1. Plan and exchange information relating to facilities used to obtain the benefits contemplated by the Treaty.

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 (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 and FCOPs for the use of Canadian storage.

6. Prepare and implement DOPs that may produce results more advantageous to both countries than those that would arise from operation under AOPs.

Additionally, the Treaty 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 Treaty. The Canadian Entity for arranging disposals of Canadian Entitlement within the United States is the government of the Province of British Columbia.

Entity Coordinators & Secretaries

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

The members are:

UNITED STATES ENTITY COORDINATORS

Gregory K. Delwiche
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
Principal Engineer, Resource Management,
Resource Management, 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
Resource Management
Power Supply
B.C. Hydro and Power Authority
Burnaby, British Columbia

Ms. Durham-Aguilera replaced Mike White as USACE Coordinator on 11 June 2003.

Columbia River Treaty Operating Committee

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

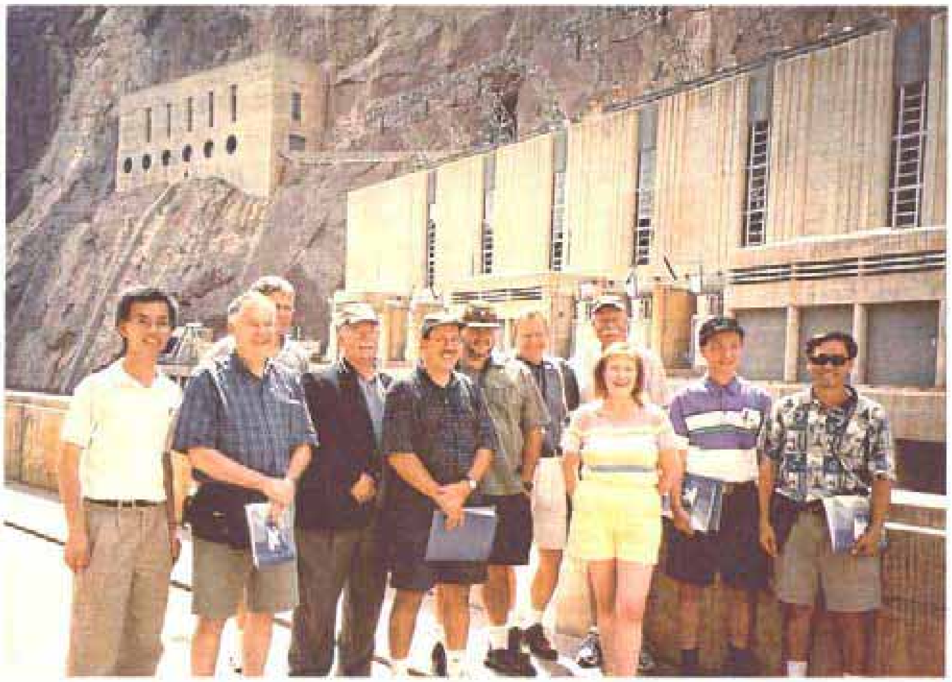
UNITED STATES SECTION	CANADIAN SECTION
Richard M. Pendergrass, BPA, Co-Chair	Kelvin Ketchum, B.C. Hydro, Chair
William E. Branch, USACE, Co-Chair	Dr. Thomas K. Siu, B.C. Hydro
Cynthia A. Henriksen, USACE	Allan Woo, B.C. Hydro
John M. Hyde, BPA	Herbert Louie, B.C. Hydro

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 Treaty storage in accordance with the current hydroelectric and FCOPs.
- Scheduled delivery of the Canadian Entitlement according to the Treaty and related agreements.
- Continued studies for the 2006-07, 2007-08 and 2008-09 AOPs/Determinations of Downstream Power Benefits (DDPB).
- Completed the 1 August 2003 through 31 July 2004 DOP.
- Updated the Libby Operating Plan (LOP) component of the LCA.
- Completed several supplemental operating agreements.
- Continued efforts to complete the Principles and Procedures for "Columbia River Treaty Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans" (POP)

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.

In addition to the above tasks, the CRTOC continued its efforts to develop a streamline method for simplifying the extensive procedures and studies currently used to prepare the AOP/DDPB. The CRTOC also continued its efforts to develop updated irrigation depletion estimates used to adjust historic streamflows for the AOP/DDPB studies.



Columbia River Treaty Operating Committee at the 17 July 2003 Meeting

Pictured from left to right: Herbert Louie (B.C. Hydro, Member), John Hyde (BPA, Member), Doug Robinson (B.C. Hydro, Canadian Entity Secretary), Tony White (BPA U.S. Entity Secretary), Kelvin Ketchum (B.C. Hydro, Chair), Rick Pendergrass (BPA, Co-chair), Eric Weiss (B.C. Hydro, Chair, Hydromet Committee), Bill Branch (USACE, Co-chair), Cindy Henriksen (USACE, Member), Tom Siu (B.C. Hydro, Member), Allan Woo (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	Eric Weiss, B.C. Hydro, Chair
Peter Brooks, USACE Co-Chair	Wuben Luo, B.C. Hydro, Member

The primary focus of the Committee this year was to implement its strategy with regards to Treaty Hydromet station definition and station monitoring. That strategy was summarized as follows:

- Consider a hydrometeorological station as Treaty/Support if the station is used to monitor, plan, and operate Treaty projects.
- Communicate with data collection agencies each year to remind them of the Committee's desire to be informed about changes in network status associated with the Columbia River basin.

- Take steps to ensure that monitoring, planning, and operations of Treaty facilities would not be detrimentally affected by proposed changes to the hydrometeorological network.
- Document changes to the hydrometeorological network.
- Regularly review existing and proposed models used for CRT planning studies and operations to assess hydrometeorological data requirements.

Another key milestone this year was the Annual Report the Committee produced, summarizing many of the important decisions that were made and creating a formalized format for reporting annual changes and committee activity. The revised format included documentation of the following:

- Committee activity during the operating year.
- Changes to the operation of Treaty/Support stations proposed within the Committee's operating year.
- Committee response to the proposed changes to the hydrometeorological network.
- Resolution of proposed changes to the hydrometeorological network.
- Processes to communicate and exchange hydrometeorological data.

The Committee was also presented with several new issues toward the close of the operating year. These issues included assessing and evaluating the use of Extended Streamflow Prediction (ESP) forecasting for Treaty purposes and developing a policy statement regarding data distribution and sensitivity. These issues will be pursued during the coming year.

Permanent Engineering Board

Provisions for the establishment of the PEB and its duties and responsibilities are included in the Treaty and related documents. The members of the PEB are presently:

UNITED STATES SECTION	CANADIAN SECTION
Stephen L. Stockton, Chair San Francisco, California	Nominee pending, Chair
Ronald H. Wilkerson, Member Missoula, Montana	Nominee pending, Member
Earl E. Eiker, Alternate nominee pending Washington, D.C.	James Mattison, Alternate Victoria, British Columbia
George E. Bell, Alternate Portland, Oregon	David E. Burpee, Alternate Ottawa, Ontario

Robert A. Bank, Secretary
Washington, D.C.

David E. Burpee, Secretary
Ottawa, Ontario

The Canadian Section ended the year with vacancies in both of the primary Board positions.

Under the Treaty, 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 deviation from the hydroelectric or FCOPs, 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 Treaty 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 Treaty related matter 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 5 February 2003 in Vancouver, B.C., 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.

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
Robert A. Bank, Chair
Washington, D.C.
Michael S. Cowan, Member
Lakewood, CO
Kamau B. Sadiki, Member
Portland, OR
D. James Fodrea, Member
Boise, ID
Earl Eiker, Member
Ellicott City, MD

CANADIAN SECTION
Roger S. McLaughlin, Chair
Victoria, British Columbia
David E. Burpee, Member
Ottawa, Ontario
Dr. G. Bala Balachandran, Member
Victoria, British Columbia
Ivan Harvie, Member
Calgary, Alberta

The PEBCOM met with the Operating Committee on 9 October 2002 in Portland, OR.

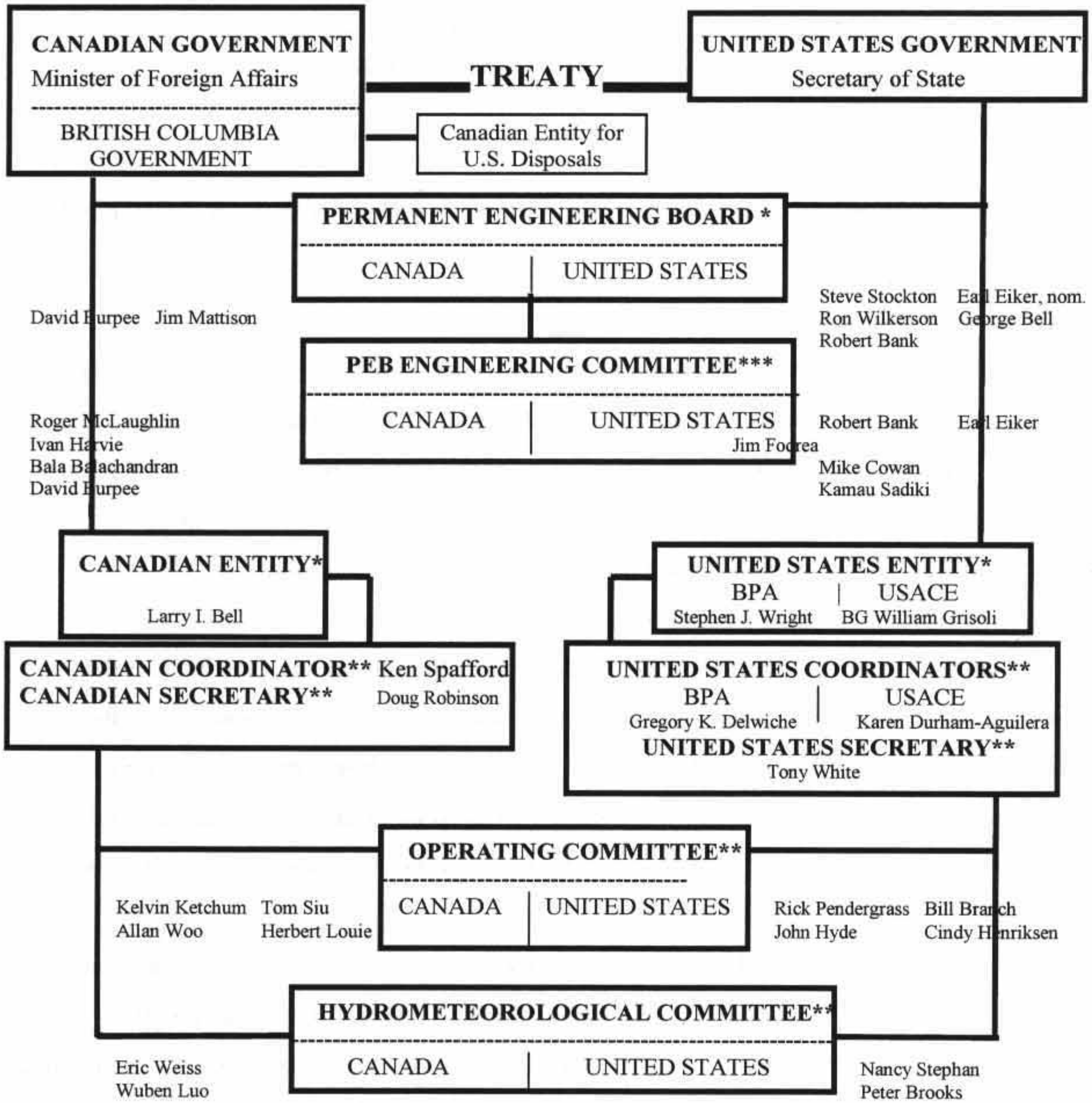
International Joint Commission

The 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 Treaty 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.

Columbia River Treaty Organization



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

III OPERATING ARRANGEMENTS

Power and Flood Control Operating Plans

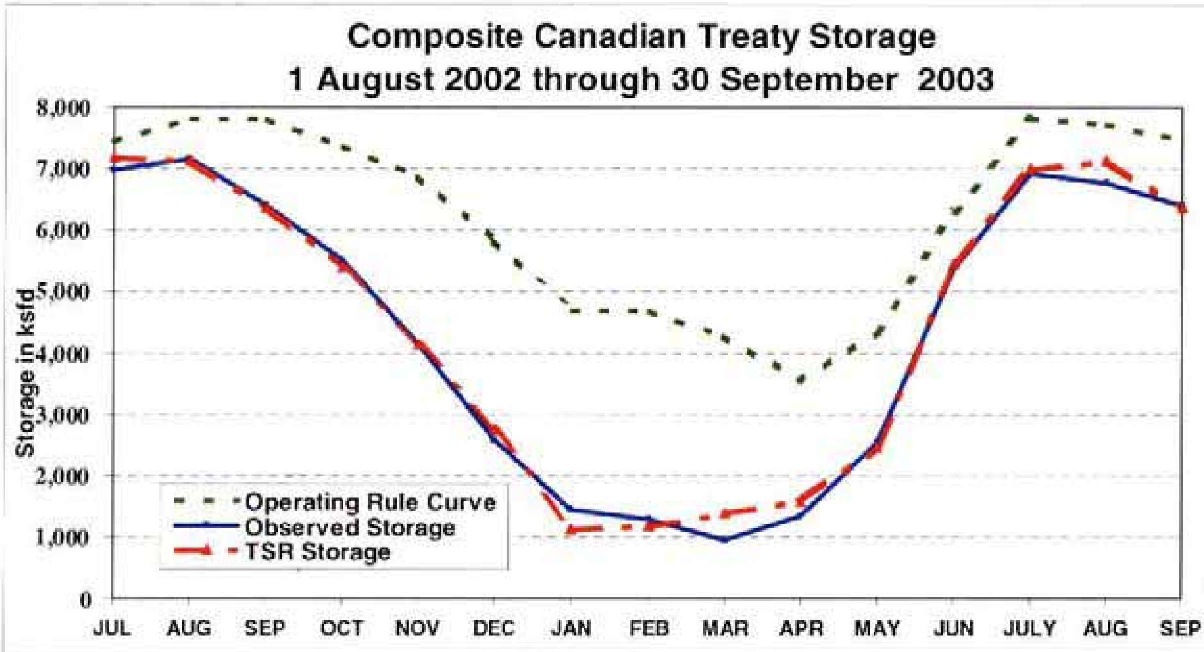
The CRT requires that the reservoirs constructed in Canada be operated pursuant to flood control and hydroelectric operating plans developed thereunder. Annex A of the Treaty: (1) stipulates that the U.S. Entity will submit FCOPs; (2) states that the Canadian Entity will operate in accordance with flood 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 hydroelectric operating plans six years in advance to furnish the Entities with an AOP for Canadian Storage. Article XIV.2.k of the Treaty provides that a DOP be developed that may produce results more advantageous than the AOP. The Protocol to the Treaty provides further detail and clarification of the principles and requirements of the Treaty.

The "Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans" dated December 1991 together with the "Columbia River Treaty Flood Control Operating Plan" dated October 1999 (updated in May 2003), establish and explain the general criteria used to develop the AOP and DOP and operate Treaty storage during the period covered by this report.

The planning and operation of Treaty Storage as discussed on the following pages is for the operating year, 1 August 2002 through 31 July 2003. The operation of Canadian Storage was determined by the 2003 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 2002-2003 AOP, with agreed changes. The changes were minor and were mainly updates to flood control rule curves, hydro-independent data, and the operation of the Brownlee project. Most of the hydrographs and reservoir charts in this report are for a 14-month period, August 2002 through September 2003.

The following chart compares the actual operation of the composite Canadian Treaty Storage to the results of the DOP TSR study. Because of very low reservoir levels at the beginning of the operating year, the TSR was regulated to draft well below the ORC during the entire operating year. Although the Coordinated System operation in the TSR recovered to the

ORC in February 2003, the TSR continued to show substantial Canadian Storage drafts below the ORC during March through July due to target and minimum flow requirements at Mica.



Assured Operating Plans

The 2002-2003 AOP dated January 2000, established ORCs, Critical Rule Curves (CRCs), Mica Operating Criteria, and other operating criteria included in the Step I Joint Optimum Power hydroregulation study that were used to develop the DOP that guided the operation of Canadian storage during the 2002-2003 operating year. The ORCs were derived from CRCs, Assured Refill Curves, Upper Rule Curves, Variable Refill Curves and Lower Limit Rule Curves, consistent with flood control requirements, as described in the 1991 Principles and Procedures document. They provide guidelines for draft and refill under a wide range of water conditions. The Flood Control Storage Reservation Curves were established to conform to the 2001 FCOP, and are used to define an upper limit to the operation of Canadian storage. The 2002-2003 AOP was developed with a 2:5 flood control split requiring 2.08 Maf of flood control space at Mica and 5.1 Maf at Arrow. Actual operations for 2002-2003 used a 4:3 flood control split, which provided 4.08 Maf at Mica and 3.6 Maf at Arrow. 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.

During the reporting period, the Entities continued their efforts to complete the 2006-2007, 2007-2008, and 2008-2009 AOP/DDPBs using the streamline method developed in the prior year. The Entities recognize that the three AOP/DDPB studies are behind the specified schedule and expect to put the AOP/DDPB process back on schedule during the next reporting period. The proposed streamline methodology meets all criteria defined in the Treaty Annexes A & B, and Protocol.

Determination of Downstream Power Benefits

For each operating year, the DDPB resulting from Canadian Treaty storage is made in conjunction with the AOP according to procedures defined in the Treaty, Annexes, and Protocol. The total Treaty downstream power benefits as a result of the operation of Canadian storage for operating years 2002-2003 and 2003-2004 were determined to be 1,068.9 MW and 1,074.6 MW average annual usable energy and 2,341.4 MW and 2,352.9 MW dependable capacity, respectively.

In conjunction with the 2006-2007, 2007-2008, and 2008-2009 AOP studies, the Entities are close to completing studies for the 2006-2007, 2007-2008, and 2008-2009 DDPB's.

Canadian Entitlement

The Canadian Entitlement to downstream power benefits was sold to the CSPE, a nonprofit consortium of 41 Northwest public and private utilities, in accordance with the CEPA dated 13 August 1964, for a period of 30 years following the Treaty-specified required completion date for each Canadian storage project. The purchase of Entitlement under CEPA expired 31 March 1998 for Duncan, 31 March 1999 for Arrow, and expired on 31 March 2003 for Mica.

On 1 April 1998 Entitlement power began returning to Canada at the U.S.-Canada border, over existing power lines, as established by the 20 November 1996 Entity Agreement on Aspects of the Delivery of the Canadian Entitlement. For the period 1 August 2002 through 31 March 2003, the amount returned based on the operation of Duncan and Arrow was 293.1 aMW of energy, scheduled at rates up to 642 MW, and for the period 1 April 2003 through 31 July 2003, the amount returned for Duncan and Arrow was 534.5 aMW of energy, scheduled at rates up to 1171 MW. For the period 1 August 2003 through 30 September 2003, the amount returned for Duncan, Arrow, and Mica was 537.3 aMW of energy, scheduled at rates up to 1176 MW.

The sale of the Canadian Entitlement to downstream power benefits resulting from the operation of Mica expired on 31 March 2003. Under the terms of the CEEA, also dated 13 August 1964, the U.S. Entity delivered capacity and energy to the CSPE participants based on the 1964 estimates of the Canadian Entitlement. Delivery under the CEEA was 93 aMW at rates up to 167 MW from 1 August 2002 through 31 March 2003.

For operating year 2002-2003 the estimate of energy benefits resulting from operating plans designed to achieve optimum operation in both countries was not less than that which would have prevailed from an optimum operation in the U.S. only, and the capacity benefit was only 0.7 MW less. Although the Entities had previously agreed in the 2002-2003 DDPB that, in accordance with Sections 7 and 10 of the CEPA, the U.S. was entitled to receive 0.3 MW of compensating dependable capacity, the Entities agreed in the 2002-2003 DOP to waive any delivery because the amount was insignificant. With the expiration of the CEPA and CEEA on 31 March 2003, future compensating energy and capacity adjustments are not required.

Detailed Operating Plan

During the period covered by this report, the Operating Committee used the 1 August 2002 through 31 July 2003 "Detailed Operating Plan for Columbia River Treaty Storage," dated July 2002 and the 1 August 2003 through 31 July 2004 DOP, dated July 2003, 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 2002-2003 DOP was based on the AOP developed for the same operating year, but the Entities decided to base the 2003-2004 DOP on the 2005-2006 AOP because of mutually beneficial changes in operating criteria. The respective AOP loads and resources, rule curves, and other operating criteria for both Canadian and U.S. projects were used to develop the TSR studies. 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 2003 were determined on the basis of seasonal volume runoff forecasts during actual operation. The VRC calculations for Canadian reservoirs and Libby for the 2002-2003 operating year are shown in Tables 2 through 5. The tabular calculation in Table 5 or VRC for Libby is used in the TSR only and is 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 DOP's and supplemental operating agreements made thereunder.

Libby Coordination Agreement

During the period covered by this report, the LCA procedures allowed the Canadian Entity to provisionally draft Arrow Reservoir and exchange power with the U.S. Entity, and required delivery to the U.S. Entity of one (1) aMW, shaped flat, over the entire operating year. In accordance with the LCA, the LOP was updated by the USACE in 2003. The LOP update was a result of a new methodology to measure flow augmentation for sturgeon at Libby Dam. The new methodology included a tiered flow approach based on the water supply forecast. The measurement made is the result of outflow at Libby Dam rather than a measurement at Bonners Ferry, Idaho, which includes local inflow.

Entity Agreements

During the period covered by this report, one U.S. Entity-only agreement was signed and one joint U.S.-Canadian arrangement was approved by the Entities:

Date Agreement Signed by Entities	Description
13 June 2003	Amendatory Agreement Number 1 to the 1997 Pacific Northwest Coordinating Agreement (PNCA)
7 July 2003	Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for 1 August 2003 through 31 July 2004

Operating Committee Agreements

During the period covered by this report, the Operating Committee approved and/or implemented five joint U.S.-Canadian agreements:

Date Agreement Signed by Committee	Description	Authority
30 August 2002	Agreement among the Columbia River Treaty Operating Committee and BPA and B.C. Hydro on the Operation of Canadian Treaty and Libby Storage Reservoirs and Exchanges of Power for the Period 8 August 2002 through 28 February 2003	Detailed Operating Plan, 1 August 2002 through 31 July 2003, approved 22 July 2002 and dated July 2002
20 November 2002	Columbia River Treaty Operating Committee Agreement on the Operation of Duncan and Kootenay Lake Reservoirs for the Period 18 November 2002 through 20 March 2003	Detailed Operating Plan, 1 August 2002 through 31 July 2003, approved 22 July 2002 and dated July 2002
23 December 2002	Columbia River Treaty Operating Committee Agreement on the Operation of Arrow and Grand Coulee Storage Reservoirs for the Period 10 December 2002 through 19 January 2003	Detailed Operating Plan, 1 August 2002 through 31 July 2003, approved 22 July 2003 and dated July 2002
10 February 2003	Columbia River Treaty Operating Committee Agreement for the Operation of Canadian Treaty Storage for the Period 1 January through 31 July 2003	Detailed Operating Plan, 1 August 2002 through 31 July 2003, approved 22 July 2002 and dated July 2002
16 July 2003	Columbia River Treaty Operating Committee Agreement on Implementation Procedures for Flood Control Reallocation for the 2003-2004 Operating Year	Detailed Operating Plan, 1 August 2003 through 31 July 2004, approved 30 June 2003 and dated July 2003

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 Treaty 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. 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.

Sub-agreements under the NTSA are monitored by the Operating Committee to ensure Treaty storage and releases are not impacted. BPA and B.C. Hydro executed a standardized

May-June storage/July-August release agreement to benefit fisheries, dated 24 April 2003, and extended the expiry date of a Treaty Special Storage Agreement under the NTSA from 20 December 2002 to 20 March 2003.

IV WEATHER AND STREAMFLOW

Weather

The 2003 WY, which began in October 2002, was cooler than normal temperature and below average precipitation. A ridge of high pressure off the Pacific Northwest coast was the dominant weather feature through much of October. Any weather disturbances that managed to break through this blocking ridge were weak and dropped only light precipitation across the region. Many low temperature records were broken on the 30th and 31st as cold arctic air mass plunged south into the U.S. from Canada. Precipitation in October was 30 percent of normal (1971-2000) at the Columbia River above Grand Coulee, 44 percent of normal at the Snake River above Ice Harbor, and 33 percent at the Columbia River above The Dalles. October 2002 was cooler than average as well. For the 31-station temperature index for the Pacific Northwest, regional temperature departed -1.8 degrees Celsius (-3.2 degrees Fahrenheit) from normal relative to the 1971-2000 normals. Mean temperature departures ranged from -3.6 to -0.1 degrees Celsius (-6.5 to -0.1 degrees Fahrenheit).

Although the second week of November brought a series of Pacific storms, high pressure was the dominant weather feature most of the month, resulting in well below normal precipitation across the region. November precipitation was: 64 percent of normal (1971-2000) at the Columbia River above Grand Coulee, 55 percent of normal at the Snake River above Ice Harbor, and 57 percent at the Columbia River above The Dalles. The accumulated WY (October through November) precipitation was: 51 percent of normal (1971-2000) at the Columbia River above Grand Coulee, 51 percent of normal at the Snake River above Ice Harbor, and 49 percent at the Columbia River above The Dalles. The regional temperature index for the Pacific Northwest departed +0.7 degrees Celsius (+1.2 degrees Fahrenheit) from normal in November.

December 2002 was a continuation of seasonal warm weather. December precipitation was: 93 percent of normal at the Columbia River above Grand Coulee, 101 percent of normal at the Snake River above Ice Harbor, and 102 percent at the Columbia River above The Dalles. The warm weather was characterized by a Pacific Northwest temperature departure of +2.9 degrees Celsius (+5.2 degrees Fahrenheit) from normal, and mean temperature departures ranging from +0.9 to +4.1 degrees Celsius (+1.7 to +7.3 degrees Fahrenheit).

January temperatures continued to be warm. January 2003 was the second warmest January on record for several cities, including Seattle, WA and Pocatello, ID. Early in the month the main storm track occasionally dipped south of the U.S.-Canadian border. This brought above normal precipitation to far northern tier basins, but left the rest of the region drier than normal. Late in the month, heavier precipitation fell across most areas as storm systems with access to tropical moisture moved into the Pacific Northwest. January precipitation was: 101 percent of normal at the Columbia River above Grand Coulee, 120 percent of normal at the Snake River above Ice Harbor, and 116 percent at the Columbia River above The Dalles. The seasonal precipitation accumulation increased slightly to: 76 percent of normal at the Columbia River above Grand Coulee, 86 percent of normal at the Snake River above Ice Harbor, and 83 percent at the Columbia River above The Dalles. There were daily precipitation records established in January including 18.3 mm (0.72 inches) at Boise, ID on the 27th, 21.8 mm (0.86 inches) at Portland, OR, 11.4 mm (0.45 inches) (tie) at Yakima, WA and 14.0 mm (0.55 inches) at the Pendleton, OR Airport on the 30th.

The 31-station temperature index for the Pacific Northwest departed +4.1 degrees Celsius (+7.3 degrees Fahrenheit) from normal in January, where mean temperature departures ranged from +2.4 to +5.9 degrees Celsius (+4.4 to +10.6 degrees Fahrenheit). New high temperature records tied or broken on the Pacific Northwest coastal areas and inland such as: 15.0 degrees Celsius (59 degrees Fahrenheit) (tie) at Portland, OR on the 4th, 13.9 degrees Celsius (57 degrees Fahrenheit) at Sea-Tac Airport on the 6th, 8.9 degrees Celsius (48 degrees Fahrenheit) at Missoula, MT on the 25th, 11.7 degrees Celsius (53 degrees Fahrenheit) at Pocatello, ID on the 27th, and 15.6 degrees Celsius (60 degrees Fahrenheit) at Pocatello, ID on the 31st. There were no new low temperature records tied or broken in January.

Early in February the subtropical jet remained positioned across the Southern U.S. leaving the Pacific Northwest under the influence of high pressure and drier than normal weather. The polar jet moved farther south late in the month, allowing a series of frontal systems to bring periods of light to moderate precipitation to the region. February precipitation was: 54 percent of normal at the Columbia River above Grand Coulee, 89 percent of normal at the Snake River above Ice Harbor, and 69 percent at the Columbia River above The Dalles. The seasonal accumulation for the WY remained well below average at the primary indices: 73 percent of normal above Grand Coulee, 87 percent at the Snake River above Ice Harbor, and 80 percent at The Dalles. The temperature index departed slightly above normal.

The month of March 2003 began dry and became wet as the month progressed. A wetter weather regime dominated through the latter part of the month as a ridge of high pressure in the Gulf of Alaska weakened and flow at upper levels became more zonal. Moderate to heavy precipitation events were experienced on the 6th-8th, 12th-14th, and 21st-22nd of March. The change is characterized by the monthly precipitation summary, where: Grand Coulee was 200 percent of normal, The Snake River at Ice Harbor was 134 percent of normal, and The Dalles 175 percent in March. This influenced the seasonal precipitation accumulations October through March: 89 percent of normal above Grand Coulee, 94 percent of normal above Ice Harbor, and 93 percent above The Dalles. The temperature index for the Pacific Northwest departed +0.8 degrees Celsius (+1.5 degrees Fahrenheit) from normal in March.

April remained wet, but cool. April precipitation was: 123 percent of normal above Grand Coulee, 143 percent of normal above Ice Harbor, and 130 percent above The Dalles. The month of April caused additional positive influence to the seasonal precipitation accumulations which were: 92 percent of normal above Grand Coulee, 100 percent of normal above Ice Harbor, and 97 percent above The Dalles. A daily precipitation record was broken in April at Yakima, WA when it received 16.3 mm (0.64 inches) of rain on the 26th. The 31-station temperature index for the Pacific Northwest departed -0.2 degrees Celsius (-0.3 degrees Fahrenheit) from normal relative to the 1971-2000 normals. Mean temperature departures ranged from -1.7 to +1.9 degrees Celsius (-3.0 to +3.4 degrees Fahrenheit).

During the month of May, the region returned to drier and warmer than normal conditions. May precipitation was: 82 percent, 94 percent, and 85 percent of normal at Grand Coulee, Ice Harbor and The Dalles, respectively. The dry conditions in May caused a return to below average seasonal accumulations in the basin: 91 percent of normal (1971-2000) at the Columbia River above Grand Coulee, 99 percent of normal at the Snake River above Ice Harbor, and 95 percent of normal at the Columbia River above The Dalles. The temperature index was near normal with departure of only -0.1 degrees Celsius (-0.1 degrees Fahrenheit) from normal, where mean temperature departures ranged from -1.4 to +1.7 degrees Celsius (-2.5 to +3.0 degrees Fahrenheit). High temperature records broken in May included 31.7 degrees Celsius (89 degrees Fahrenheit) at Pocatello, ID and 36.1 degrees Celsius (97 degrees Fahrenheit) (tie) at Boise, ID on the 24th, 36.1 degrees Celsius (97 degrees Fahrenheit) at Pocatello, ID and 37.2 degrees Celsius (99 degrees Fahrenheit) (tie) at Boise, ID on the 28th, and 35.0 degrees Celsius (95 degrees Fahrenheit) at Boise, ID (tie) and 35.6 degrees Celsius (96 degrees Fahrenheit) at Pocatello, ID on the 29th. Low temperature records broken in May included -0.6 degrees Celsius (31 degrees Fahrenheit) at Pendleton, OR on the 7th, 0.0 degrees Celsius (32 degrees Fahrenheit) at Pendleton, OR on the 8th; 4.4 degrees Celsius

(40 degrees Fahrenheit) at Seattle, WA on the 16th; -3.9 degrees Celsius (25 degrees Fahrenheit) at Kalispell, MT and -1.7 degrees Celsius (29 degrees Fahrenheit) at Yakima, WA on the 17th; 2.8 degrees Celsius (37 degrees Fahrenheit) at Seattle, WA, and 3.3 degrees Celsius (38 degrees Fahrenheit) at Portland, OR on the 18th; -5.0 degrees Celsius (23 degrees Fahrenheit) at Pocatello, ID, -0.6 degrees Celsius (31 degrees Fahrenheit) at Pendleton, OR, 0.0 degrees Celsius (32 degrees Fahrenheit) at Spokane, WA, and 4.4 degrees Celsius (40 degrees Fahrenheit) at Portland, OR on the 19th; and -5.0 degrees Celsius (23 degrees Fahrenheit) at Pocatello, ID on the 20th. Seasonal snowpack accumulation at the Columbia River above The Dalles is shown in Chart 2. Seasonal below average precipitation has resulted in below average snowpack.

The month of June kept the region in a dry warm weather pattern. June was drier than May with precipitation of: 69 percent of normal above Grand Coulee, 38 percent of normal above Ice Harbor, and 50 percent above The Dalles. This again brought the seasonal average precipitation accumulations down to: 88 percent above Grand Coulee, 93 percent above Ice Harbor, and 91 percent above The Dalles. The dry conditions were accentuated by new record low precipitation for the entire month at Pendleton, OR and Yakima, WA where only a trace of precipitation fell. The warm conditions were quantified by a temperature index departure of +1.2 degrees Celsius (+2.2 degrees Fahrenheit) from normal in June. Some high temperature records in June were 32.8 degrees Celsius (91 degrees Fahrenheit) on the 4th and 35.6 degrees Celsius (96 degrees Fahrenheit) on the 5th at Portland, OR, and 34.4 degrees Celsius (94 degrees Fahrenheit) (tie) at Pendleton, OR on the 7th.

July was very dry. July precipitation was: 18 percent of normal (1971-2000) at the Columbia River above Grand Coulee, 36 percent of normal at the Snake River above Ice Harbor, and 20 percent of normal at the Columbia River above The Dalles. This further reduced the seasonal accumulated precipitation to: 83 percent of normal (1971-2000) at the Columbia River above Grand Coulee, 90 percent of normal at the Snake River above Ice Harbor, and 87 percent of normal at the Columbia River above The Dalles. July temperature departures remained above normal at +2.7 degrees Celsius (+4.9 degrees Fahrenheit).

August continued very dry and warm. The precipitation was only 32 percent, 107 percent and 56 percent of normal at Grand Coulee, Ice harbor and The Dalles, respectively. Although Ice Harbor precipitation was 107 percent of normal, normal precipitation is only 21.8 mm (0.86 inches) during August. Seasonal precipitation from October 2002 through August 2003 continued below average across the basin at: 79 percent of normal above Grand Coulee, 91 percent of normal above Ice Harbor, and 85 percent above The

Dalles. The 31-station temperature index for the Pacific Northwest departed +1.7 degrees Celsius (+3.0 degrees Fahrenheit) from normal relative to the 1971-2000 normals. Mean temperature departures ranged from -0.2 to +3.7 degrees Celsius (-0.3 to +6.7 degrees Fahrenheit). High temperature records tied or broken in August included 37.2 degrees Celsius (99 degrees Fahrenheit) at Kalispell, MT and 37.8 degrees Celsius (100 degrees Fahrenheit) at Pocatello, ID on the 10th, and 37.2 degrees Celsius (99 degrees Fahrenheit) at Pocatello, ID on the 13th.

In September, the upper level high held for at least part of the month, but the storm track punched inland temporarily. This allowed a series of fronts to bring some precipitation into portions of the basin. Precipitation was 92 percent of normal at the Columbia River above Grand Coulee and 83 percent of normal at the Columbia River above The Dalles. September was a warm month, with record high temperatures at Portland of 35 degrees Celsius (95 degrees Fahrenheit) and Pendleton of 37.8 degrees Celsius (100 degrees Fahrenheit). The 31-station temperature index for the Basin departed +1.3 degrees Celsius (+2.3 degrees Fahrenheit). Accumulated seasonal precipitation percentage for the water year September 2002 through October 2003 is shown in Chart 1. Accumulated precipitation month by month at selected basins is shown in Chart 3. Monthly temperature departures throughout the basin can be found in Chart 4.

Streamflow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 August 2002 through 30 September 2003 are shown on Charts 5 through 7. Chart 8 shows Libby hydrographs. Observed flow with the computed unregulated flow hydrographs for the same 14-month period for Kootenay Lake, the Columbia River at Birchbank, Grand Coulee and The Dalles are shown on Charts 9, 10, 11, and 12, respectively. Chart 13 is a hydrograph of observed and unregulated flows at The Dalles during the April through July 2003 period, including a plot of flows occurring if regulated only by the four Treaty reservoirs.

Composite unregulated streamflow in the basin above The Dalles was generally below average through the winter months. There were some flows above average in early February and April 2003. Although the peak flow of the freshet was slightly above average at The Dalles, unregulated flow quickly receded and July and August streamflow of 2003 were well below average. July unregulated flow was 12.21 km^3 (9.930 Maf), 63% of average, and August unregulated flow was 6.94 km^3 (5.642 Maf), 67% of average. This was the fourth lowest July unregulated flow based on the period 1928–1988 and the lowest August flow based on the same period. Chart 12 shows the unregulated streamflow (Summary Hydrograph) at The Dalles.

Columbia River Flow in 2002-2003 Metric Units

Time Period	Columbia River at Grand Coulee in m^3/s Natural Flow	Columbia River at Grand Coulee in m^3/s Percentage of Average	Columbia River at The Dalles in m^3/s Natural Flow	Columbia River at The Dalles in m^3/s Percentage of Average
Aug 02	2,241	75	2,892	74
Sep 02	1,386	79	2,044	77
Oct 02	801	63	1,523	65
Nov 02	770	56	1,607	60
Dec 02	835	68	1,630	58
Jan 03	930	78	2,212	76
Feb 03	1,076	80	2,891	84
Mar 03	1,956	111	4,336	95
Apr 03	3,621	104	6,024	92
May 03	5,829	77	9,464	77
Jun 03	8,325	95	11,722	88
Jul 03	3,733	69	4,578	63
Aug 03	2,043	69	2,601	67
Sep 03	1,191	68	1,748	66
Operating Year Average (Oct 02 – Sep 03)	2,595	81	4,198	78

Columbia River Flow in 2002-2003 Metric Units

Time Period	Columbia River at Grand Coulee in m^3/s Natural Flow	Columbia River at Grand Coulee in m^3/s Percentage of Average	Columbia River at The Dalles in m^3/s Natural Flow	Columbia River at The Dalles in m^3/s Percentage of Average
Aug 02	2,241	75	2,892	74
Sep 02	1,386	79	2,044	77
Oct 02	801	63	1,523	65
Nov 02	770	56	1,607	60
Dec 02	835	68	1,630	58
Jan 03	930	78	2,212	76
Feb 03	1,076	80	2,891	84
Mar 03	1,956	111	4,336	95
Apr 03	3,621	104	6,024	92
May 03	5,829	77	9,464	77
Jun 03	8,325	95	11,722	88
Jul 03	3,733	69	4,578	63
Aug 03	2,043	69	2,601	67
Sep 03	1,191	68	1,748	66
Operating Year Average (Oct 02 – Sep 03)	2,595	81	4,198	78

Columbia River Flow in 2002-2003 in English Units

	Columbia River at Grand Coulee in cfs		Columbia River at The Dalles in cfs	
Time Period	Natural Flow	Percentage of Average	Natural Flow	Percentage of Average
Aug 02	79,195	75	102,199	74
Sep 02	48,990	79	72,222	77
Oct 02	28,315	63	53,828	65
Nov 02	27,222	56	56,768	60
Dec 02	29,521	68	57,608	58
Jan 03	32,877	78	78,152	76
Feb 03	38,023	80	102,146	84
Mar 03	69,127	111	153,232	95
Apr 03	127,946	104	212,871	92
May 03	205,963	77	334,425	77
Jun 03	294,158	95	414,192	88
Jul 03	131,916	69	161,779	63
Aug 03	72,190	69	91,919	67
Sep 03	42,087	68	61,784	66
Operating Year Average				
(Oct 02 – Sep 03)	91,710	81	148,350	78

Seasonal Runoff Forecasts and Volumes

Observed 2003 April through August 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	6.271	5,084	81
Duncan Reservoir Inflow	2.326	1,886	92
Mica Reservoir Inflow	12.841	10,410	92
Arrow Reservoir Inflow	24.750	20,065	88
Columbia River at Birchbank	43.090	34,934	86
Grand Coulee Reservoir Inflow	61.974	50,243	83
Snake River at Lower Granite	21.768	17,648	77
Columbia River at The Dalles	61.974	50,243	83

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2003 for a large number of locations in the Columbia River Basin and updated each month as the season advanced. Table 1 lists the April through August inflow volume forecasts for Mica, Arrow, Duncan and Libby projects and for unregulated runoff for the Columbia River at The Dalles. Also shown in Table 1 and Table 1M are the actual volumes for these five locations. 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 USACE, National Resource Conservation Service, Bureau of Reclamation, and B.C. Hydro. The 1 April 2003 forecast of January through July runoff for the Columbia River above The Dalles was 105.2 km^3 (85.3 Maf) and the actual observed runoff was 108.2 km^3 (87.7 Maf).

The following tabulation summarizes monthly forecasts since 1970 of the January through July runoff for the Columbia River above The Dalles compared with the actual runoff measured in km^3 (Maf). The average January-July runoff for the 1971-2000 period was 132.35 km^3 (107.3 Maf).

The Dalles 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	104.5	104.2	101.1	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	134.5	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	106.1	95.3	94.5	101.0	106.2	108.5
1994	98.3	94.1	96.3	90.3	93.1	94.2	92.5
1995	124.6	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	146.8	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	123.4	125.8	120.0	118.9	121.1	123.4	128.0
2003	99.3	93.3	92.4	105.2	111.3	110.1	108.2

The Dalles 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	1193.0	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

V RESERVOIR OPERATION

General

The 2002-2003 operating year began with the system more than 90 percent full. The fall season through December was characterized by dry weather and below average snowpack. As a result, the January water supply forecast at The Dalles for the period January through July was only 80.5 Maf (76 percent) of average. This was a similar forecast to the drought year of 2001. Although 2003 continued to be dry, the water supply forecasts did not vary significantly. March and April were characterized by more precipitation, but they did not contribute to the snowpack component of the water supply and therefore the seasonal water supply at The Dalles was only 87.7 Maf (82 percent) of average for January through July.

The Federal system was operated to meet the needs of listed chum downstream of Bonneville Dam beginning 6 November 2002. The operation meant maintaining the tailwater elevation at Bonneville Dam at, or above, elevation 3.44 meters (11.3 feet), so as to keep the areas downstream of Bonneville wetted while the chum moved into the area and spawned. This tailwater elevation was the minimum allowable to Bonneville through the emergence of the chum in May.

Operation for the National Marine Fisheries Service (NMFS, which is currently called NOAA Fisheries) BiOp, and the USFWS BiOp were completed in 2002-2003. The operations included refilling reservoirs to the 10 April flood control elevation. If inflow was great enough, refill on, or about, 30 June; and drafting reservoirs to summer draft limits. Because March and April were somewhat wet, the spring flow objectives at Priest Rapids, Lower Granite, and McNary were met. Spill was executed for spring and summer 2002 at all projects, and the Lower Snake River projects were operated at, or near, their minimum operating pools for the season.

Canadian Treaty Storage Operation

At the beginning of the 2002-2003 operating year, 31 July 2002, actual Canadian Treaty storage (Canadian storage) was at 17.4 km^3 (14.1 Maf) or 91.3 percent full. Canadian storage continued to refill marginally through August 2002 before beginning to draft in September, reaching 2.3 km^3 (1.9 Maf) on 31 March 2003. Canadian storage did not refill fully during the operating year, reaching 17.0 km^3 (13.7 Maf) or 88.7 percent full on 31 July 2003.

As specified in the DOP, the release of Canadian Treaty storage is made effective at the Canadian-U.S. border. Accordingly, releases from individual Canadian projects can vary from the release required by the DOP TSR plus supplemental operating agreements so long as this variance does not impact the ability of the Canadian system to deliver the sum of Treaty outflows from Arrow and Duncan Reservoirs. Variances from the DOP storage operation are accumulated in respective Flex accounts. An overrun in an account occurs when actual project releases are greater (contents are lower) than those specified by the DOP. Conversely, an underrun occurs when actual project releases are less (contents are higher) than those specified by the DOP. Flex accounts for Mica, Revelstoke, Arrow and Duncan are balanced at any point in time to ensure that under/overruns do not impact the total Treaty 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 reached its maximum elevation of 751.37 m (2465.1 feet) on 3 September 2002. The reservoir drafted rapidly during October through December, reaching 733.23 m (2,405.6 feet) by 31 December, 2.62 m (8.6 feet) above the historical minimum elevation for that date. The reservoir continued to draft January through March, reaching a minimum elevation of 714.09 m (2,342.8 feet), on 8 April 2003. Refill level of the Mica Reservoir during the operating year was impacted by a low initial level as well as below normal seasonal inflows. As a result, reservoir refill level for the operating year was much below normal, reaching a maximum elevation of 744.32 m (2442.0 feet) on 23 August 2003, 10.1 m (33.0 feet) below full pool.

Inflow into Mica Reservoir was 75 percent of normal over the period August 2002 to December 2002. Over this same period, Mica outflow varied from a monthly average low of 436 m^3/s (15,400 cfs) in August to a monthly average high of 1062 m^3/s (37,500 cfs) in December. Inflow into Mica Reservoir was 92 percent of normal over the period January 2003 to August 2003. Outflow over this same period varied from a monthly average high of 926 m^3/s (32,700 cfs) in January to a monthly average low of 34 m^3/s (1,200 cfs) in June.

The Mica project had an underrun of 548.73 cubic hectometers (hm^3) (224.3 thousand second-foot-days (ksfd)) on 31 July 2002. The underrun continued to increase to 1497.5 hm^3 (612 ksfd) by September 5, 2002. The underrun was subsequently reduced to about zero by 9 April 2003 before increasing again to 626 hm^3 (256 ksfd) by 31 August 2003. The

B.C. Hydro NTSA was at 1823.6 hm^3 (744.8 ksfd) on 31 July 2002 and 1346 hm^3 (550 ksfd) on 31 August 2003. The corresponding U.S. NTSA was at 2322.4 hm^3 (949.5 ksfd) and 1072 hm^3 (438.2 ksfd), respectively.

Revelstoke Reservoir

During the 2002-2003 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 feet). During the spring freshet, March through July, the reservoir operated as low as elevation 571.60 m (1,875.3 feet), or 1.34 m (4.7 feet) below full pool, to provide additional operational space to control high local inflows. Changes in Revelstoke storage levels did not affect Treaty storage operations.

Arrow Reservoir

As shown in Chart 6, the Arrow Reservoir was at elevation 439.09 m (1440.6 feet) on 31 July 2002. The coordinated hydro system was on proportional draft from August 2002 through January 2003. This contributed to the Arrow Reservoir being drafted to its minimum elevation much earlier than normal, reaching 424.68 m (1393.3 feet) by 3 February 2003. The reservoir reached its maximum level of the year at elevation 439.09 m (1440.6 feet) on 4 July 2003, 1.04 m (3.4 feet) below full pool.

Local inflow into Arrow Reservoir was 66 percent of normal over the period August 2002 to December 2002. Due to the proportional draft of the hydro system, Arrow outflows were approximately 20 percent higher than the historical average for this corresponding period. Arrow outflow varied from a monthly average low of 1240.3 m^3/s (43,800 cfs) in October to a monthly average high of 1642.4 m^3/s (58,000 cfs) in November. Local inflow into Arrow Reservoir was 84 percent of normal over the period January 2003 to August 2003. Outflow over this same period varied from a monthly average high of 1662.2 m^3/s (58,700 cfs) in August to a monthly average low of 424.8 m^3/s (15,000 cfs) in April.

Arrow Reservoir operation was modified during the operating year under three Operating Committee Agreements to enhance whitefish and rainbow trout spawning and emergence downstream of the Arrow project in British Columbia and to provide additional power and non-power benefits in the U.S. From 21 December 2002 to 31 January 2003, Arrow outflow was held near 1274.3 m^3/s (45,000 cfs) to maintain low river levels during the whitefish spawning period. This operation reduced the likelihood of eggs being dewatered during the emergence period in February and March 2003. Arrow outflow through the emergence period from 1 February to 21 March 2003 was held between 572 m^3/s and 849.5 m^3/s (20,200 cfs and 30,000 cfs) to help protect deposited eggs. During April and May 2003, Arrow outflows were held between 424.8 m^3/s and 566.4 m^3/s (15,000 cfs and 20,000 cfs) to ensure successful rainbow trout spawning immediately below Arrow, at water levels that could be maintained until hatch.

Duncan Reservoir

As shown in Chart 7, the Duncan Reservoir filled during 2002, reaching a maximum of 576.78 m (1892.3 ft), 0.1 m (0.3 ft) above full pool on 16 July 2002. A high inflow event coinciding with the full reservoir caused discharges to reach 411 m^3/s (14,500 cfs) from 17 July to 20 July 2002. The project passed inflows until 10 August 2002 when the reservoir started to draft. In the latter half of August, Duncan discharge was maintained around 227 m^3/s (8,000 cfs) as part of a Libby/Canadian storage exchange agreement (as reported in the 2001-02 Annual Report). During the period of September through December 2002, Duncan discharge was maintained at or below 227 m^3/s (8,000 cfs) to supplement inflow into Kootenay Lake. By mid-January 2003, the reservoir was at minimum pool and was passing inflows.

Reservoir discharge was reduced to the minimum of 3 m^3/s (100 cfs) on 11 May 2003 to initiate refill. The observed season water supply at Duncan for the February through September period was 94 percent of normal. Discharge from the project was increased from 3 m^3/s (100 cfs) to 170 m^3/s (6000 cfs) as the reservoir reached 576.4 m (1891 ft), 0.3 m (1 ft) below full pool on 1 August 2003. The reservoir was maintained at 0.3 m (1 ft) below full pool through August as a flood buffer and to support recreation on the reservoir.

In September, the project discharge was increased to between 227 m^3/s and 283 m^3/s (8,000 cfs and 10,000 cfs) to draft the reservoir prior to kokanee and whitefish spawning. Discharges were reduced to 73.6 m^3/s (2600 cfs) to facilitate spawning at lower flows to limit the risk of over-winter dewatering of redds.

Libby Reservoir

As shown in Chart 8, Lake Koocanusa began July 2002 at elevation 749.02 m (2456.8 feet), 0.67 m (2.2 feet) from full. Inflow to the reservoir was 1400 m^3/s (50,000 cfs) on 1 July and receding slowly and Libby spilled as much as 420 m^3/s (15,000 cfs) on 2 July and stopped spill on 7 July. By 9 July inflow increased again because of hot weather and spill of up to 140 m^3/s (5,000 cfs) was initiated again 11 through 17 July. The reservoir filled slightly through the first half of the month and filled to its highest level of 749.6 m (2458.6 feet) on 15 July, within 0.12 m (0.4 feet) from full. Outflow from Libby remained near 616 m^3/s (22,000 cfs) for the remainder of July. The reservoir then began to draft and was at elevation 748.5 m (2455.1 feet) by the end of July 2002.

In August 2002, Lake Koocanusa began to draft toward elevation 743.6 m (2439 feet) to meet the draft limits outlined in the NMFS BiOp. In 2002 the U.S. and Canada reached an agreement for a Libby/Duncan storage exchange as outlined in Attachment D of the LCA. The storage exchange agreement was for no more than 171 hm^3 (70 ksfd); therefore Lake Koocanusa targeted an end of August elevation of 744.6 m (2442.3 feet) rather than the normal BiOp interim draft limit of elevation 743.6 m (2439 feet). The draft was accomplished by releasing relatively steady outflow between 476 m^3/s (17,000 cfs) and 616 m^3/s (22,000 cfs) for most of August. The outflow was reduced the last few days of August to make a smooth transition into fall operations.

In September 2002 Libby released 168 m^3/s (6,000 cfs) and the reservoir drafted 0.6 m (2 feet). By 18 October, the outflow was reduced to 135 m^3/s (4,800 cfs) and Libby Reservoir drafted on 0.8 m (2.6 feet) in October to elevation 743.3 m (2437.9 feet). The outflow was held at 135 m^3/s (4,800 cfs) through November except for a short increase near the end of the month for power generation.

The operating strategy in December 2002 was to release outflow for optimal power generation and draft Lake Koocanusa to elevation 735 m (2411 feet) by the end of December. The power objectives were achieved by releasing as much as full powerhouse outflow through 21 December, and shape flow through the week. On 22 December, the outflow was reduced using the slow ramp down rates recommended in the USFWS bull trout BiOp. By 25 December, Libby was releasing 204 m^3/s (7,300 cfs) and reached it objective of elevation 735 m (2411 feet) on 31 December. The low outflow at the end of December and the continuing low flow through January may have enhanced burbot movement in the Kootenai River.

In January 2003 the USACE adopted use of the VARQ flood control operation for interim use. Based on the January water supply forecast at Libby of 6007 hm^3 (4.861 Maf) (78 percent of average) for the April through August period, the end of January VARQ flood control target elevation was 739.8 m (2426.7 feet), and the 15 March target flood control elevation was 744.2 m (2441.1 feet). January inflow to Libby was less than 112 m^3/s (4,000 cfs), and the dam reduced outflow to its normal minimum outflow of 112 m^3/s (4,000 cfs). The February and March water supply forecasts remained well below average and the flood control target elevations remained well above reservoir elevations that could physically be achieved. Libby Dam continued to release minimum outflow of 112 m^3/s (4,000 cfs) through March and into April and was unable to refill to the flood control elevation. By March the water supply forecast had deteriorated to 5167 hm^3 (4.181 Maf) (67 percent of average) and the end of April flood control target was as high as elevation 749 m (2456.8 feet), only 0.67 m (2.2 feet) from full. However low inflow since January kept the reservoir drafting, and the actual elevation of Libby Reservoir was as low as elevation 733 m (2404.2 feet) at the end of March, 13.4 m (43.8 feet) below the VARQ flood control elevation. There was some increase of inflow to the reservoir in April and although Libby continued to release only 112 m^3/s (4,000 cfs) in April, the reservoir only refilled to elevation 735.2 m (2411.3 feet).

During May 2003 the inflow to Libby increased somewhat and the peak of the freshet was slightly greater than 1512 m^3/s (54,000 cfs) on 30 May. The dam continued to release only 112 m^3/s (4,000 cfs) in May and refilled to elevation 743 m (2435.5 feet) on 31 May, only 7.2 m (23.5 feet) from full. In June and July the operating strategy shifted to meet operations for listed sturgeon in the Kootenai River to meet the objectives of the USFWS BiOp. To meet those objectives, the USACE was to release 988 hm^3 (800 kaf) from Libby in excess of minimum flow of 112 m^3/s (4,000 cfs) and try to refill the reservoir by 30 June and not spill. These objectives were achieved by increasing the outflow from Libby to near 700 m^3/s (25,000 cfs) (maximum powerhouse outflow) by 7 June and maintaining that outflow for 12 days before reducing slightly to 532 m^3/s (19,000 cfs). This operation was timed to enhance the release of larval sturgeon in the Kootenai River. At the end of June inflow to the reservoir was at or slightly less than powerhouse outflow capacity and Lake Koocanusa was at elevation 749.3 m (2457.6 feet), 0.43 m (1.4 feet) from full. Lake Koocanusa filled to within one foot of full on 2 July and remained in the top foot through 15 July, when the reservoir began to draft to meet the 31 August draft limit for the BiOps of elevation 743.6 m (2439 feet). Outflow from Libby was held between 392 m^3/s (14,000 cfs) and 504 m^3/s (18,000 cfs) for the remainder of July and August to draft to this elevation. There was not agreement reached for a Libby - Arrow storage exchange in 2003 because of unfavorable hydrologic conditions in Canada.

In September 2003 the outflow was reduced to no lower than 168 m^3/s (6,000 cfs) to maintain wetted habitat in the Kootenai River downstream of Libby, and the reservoir drafted to near elevation 742 m (2434 feet).

Kootenay Lake

As shown in Chart 9, the level of Kootenay Lake at Queens Bay was elevation 532.43 m (1746.8 ft) on 31 July 2002 and drafted to a low of 530.50 m (1740.5 ft) on 2 December 2002. The lake levels remained well below the IJC levels throughout the fall in order to minimize spill at the Brilliant project later in the year and to meet system requirements. The lake refilled in December due to increased discharges from Libby.

Kootenay Lake was drafted during January to March to remain below the maximum IJC level and to meet generation requirements. On 11 March 2003, Kootenay Lake was at its minimum elevation of 530.01 m (1738.9 ft). Increasing inflows in March resulted in the Kootenay Lake reaching 530.12 m (1739.2 ft) on 1 April.

During April, as inflow increased beyond the maximum outflow capacity, the lake elevation rose to 530.52 m (1740.55 ft) by the end of the month. The Kootenay Lake Board of Control declared the commencement of the spring rise for the regulation of Kootenay Lake on 25 April 2003. Following the declaration of spring freshet, Kootenay Lake was operated in accordance to the IJC lowering formula.

Kootenay Lake discharges remained near inflows until the Kootenay Lake level rose sharply in response to the spring freshet inflow in late May. Kootenay Lake discharge was increased in accordance with the IJC order for Kootenay Lake. Regulated inflow peaked at 2216 m^3/s (78,000 cfs) on 9 June 2003. Discharge from the lake peaked at 1725 m^3/s (61,000 cfs) on 21 June 2003. Kootenay Lake peaked at elevation 533.08 m (1748.95 ft) on 19 June 2003.

Kootenay Lake levels started to drop due to receding runoff and discharges were adjusted to control reservoir levels slightly below the IJC limits. The level at the Nelson gauge drafted below the trigger elevation of 531.36 m (1743.32 ft) on 1 August 2003. Discharges were adjusted to control the Nelson gauge slightly below that level until the end of August, at which time the Queen's Bay level was 531.46 m (1743.60 ft).

Storage Transfer Agreements

The CRTOC initiated a U.S.–Canada storage transfer on 8 August 2002 and signed the agreement on 30 August 2002. Initially the operating objective was to have Libby Reservoir 171.26 hm^3 (70 ksfd) above the BiOp draft limit elevation of 743.41 m (2439.0 feet). An equal volume of water was to be released from Canadian storage in August so that Canadian Treaty storage would end August 171.26 hm^3 (70 ksfd) below its end of month content.

As August progressed the hydrologic conditions deteriorated and the TSR was drafting Canadian storage to much deeper end of month draft points. By 31 August 2002, Libby was 154.13 hm^3 (63 ksfd) above its draft limit at elevation 744.30 m (2441.93 feet), Canadian Treaty storage was targeting 154.13 hm^3 (63 ksfd) below TSR but there was 229.97 hm^3 (94 ksfd) of inadvertent Canadian Treaty storage because actual inflows were less than forecasted in the 8 August TSR. Separately from the U.S.-Canada storage transfer agreement, on 31 August 2002, Canada provided proportional draft by drafting Treaty storage 437.92 hm^3 (179 ksfd).

During the summer of 2003 hydrologic conditions in Canada were not favorable. As a result a U.S.-Canada storage transfer agreement was not agreed upon in 2003.

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 DOPs prepared since the installation of generation at Mica, the 2002-2003 and 2003-2004 DOPs were designed to achieve optimum power generation at-site in Canada and downstream in Canada and the U.S., in accordance with paragraph 7 of Annex A of the Treaty.

During the period covered by this report, Libby power operations in the Treaty Storage Regulation (TSR) were developed in accordance with the Treaty and the 1999 CRT FCOP (updated in May 2003). During a portion of the year, Libby operated for power purposes. During December through early February 2003 the USACE coordinated operations for burbot in the Kootenai River, which had been proposed for listing. As recommended by the Corps on 31 December 2002, Libby operated to VARQ (Variable flow) flood control on an interim basis in 2003. From June through August, Libby operated for storage and releases recommended for endangered white sturgeon and salmon by the 2000 USFWS and NMFS BiOps.

Flood Control

With the 2003 water supply forecasts well below average across the Columbia River Basin, the reservoir system, including the CRT projects required minimal draft for flood control in preparation for the spring freshet. Inflow forecasts and end of month flood control elevation targets were calculated monthly throughout the spring. Projects were operated according to the 1999 and 2003 FCOP. Although Libby operated to VARQ flood control in 2003, the inflow was well below minimum outflow of 113.27 m^3/s (4000 cfs) and the reservoir could not refill to the VARQ flood control elevation. Nor would the reservoir have filled to Columbia River and Tributaries Study (CRT 63) flood control elevation. The unregulated peak flow at The Dalles, OR, shown on Chart 13, is estimated at 16,772 m^3/s (592,330 cfs) on 1 June 2003 and a regulated day average peak flow of 10,024 m^3/s (354,200 cfs) occurred on 31 May 2003. The unregulated peak stage at Vancouver, WA was calculated to be 6.34 m (20.8 feet) on 2 June 2003 and the highest-observed stage was 4.25 m (14.0 feet) on 1 February 2003, which can be seen on Chart 12.

Chart 14 shows the relative filling of Arrow and Grand Coulee during the filling period and compares the regulation to guide lines, Chart 6, of the CRT Flood Control Operating Plan. During the spring Mica to be drafted for power and there were no daily operations specified for Arrow. The projects were able to meet both fish flow and flood control objectives. In operating year 2002-2003 Mica and Arrow operated to "shifted" flood control as defined in the 2000 FCOP. In 2002 B.C. Hydro requested 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. The U.S. Section of the CRTOC responded affirmatively to this request on 7 November 2002.

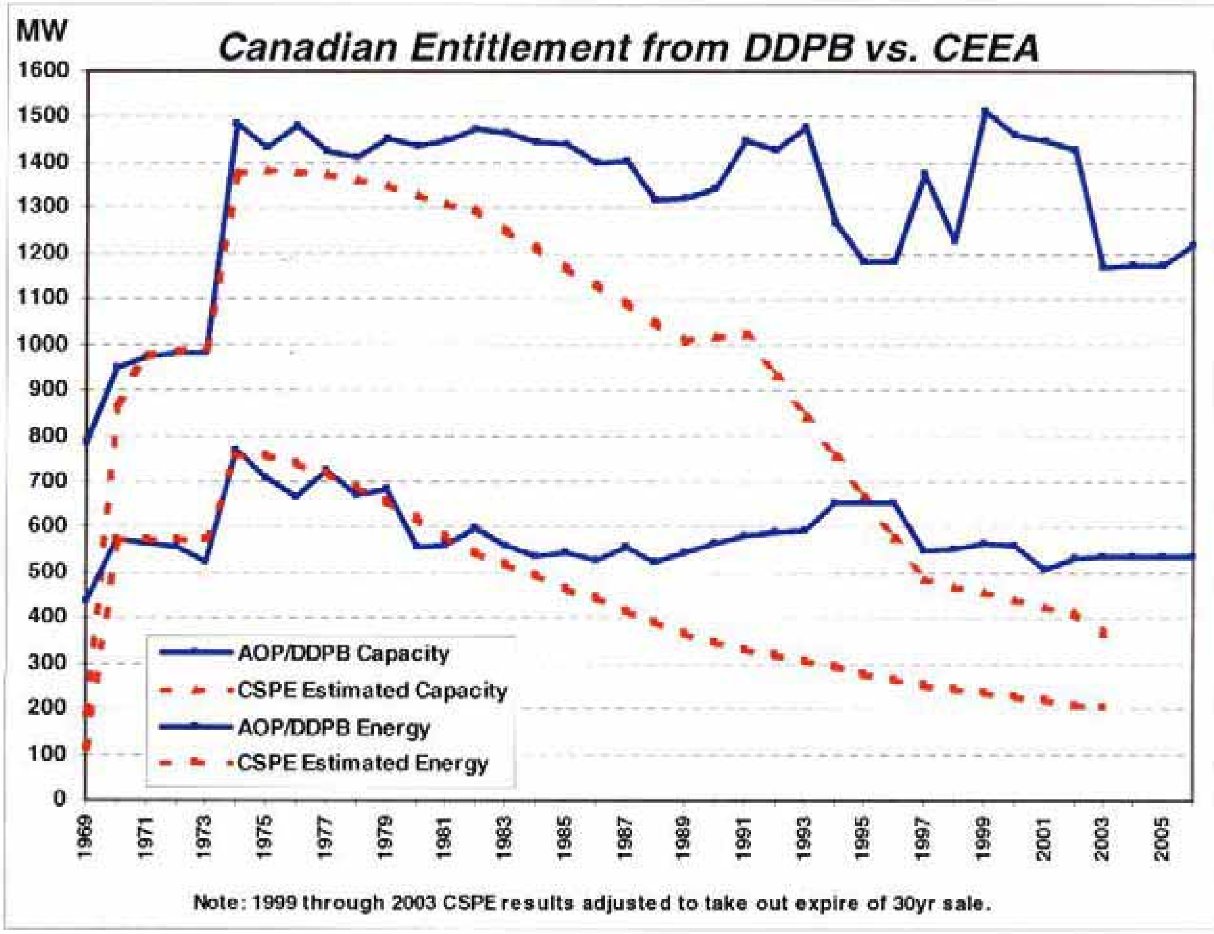
Computations of the Initial Controlled Flow (ICF) for system flood control operation were made in accordance with the Treaty Flood Control Operating Plan. Computed ICFs at The Dalles were 8,155 m^3/s (288,000 cfs) on 1 January 2003; 6,201 m^3/s (219,000 cfs) on 1 February 2003; 6,315 m^3/s (223,000 cfs) on 1 March 2003; 7,532 m^3/s (266,000 cfs) on 1 April 2003; and 8,523 m^3/s (301,000 cfs) on 1 May. As mentioned earlier, the observed peak flow at The Dalles was 10,024 m^3/s (354,200 cfs) on 31 May 2003. Data for the 1 May ICF computation are given in Table 6.

Within Canada the flow at Birchbank demonstrated local flood protection. Chart 10 shows the regulated and unregulated flow at Birchbank. The maximum regulated flow at Birchbank was 2,858 m^3/s (101,000 cfs), the unregulated flow was 6,169 m^3/s (218,000 cfs).

Canadian Entitlement

From 1 August 2002 through 31 March 2003, the U.S. Entity delivered the Canadian Entitlement to downstream power benefits from the operation of Duncan and Arrow Reservoirs to the Canadian Entity, at existing points of interconnection on the Canada-U.S. border. With the full expiration of CEPA on 31 March 2003, the U.S. Entity delivery of the Canadian Entitlement began to include the downstream power benefits from Mica, in addition to those from Duncan and Arrow Reservoirs. The amounts returned, not including transmission losses and scheduling adjustments, are listed in Section III. No Entitlement power was disposed directly in the U.S. during 1 August 2002 through 31 September 2003, as was allowed by the 29 March 1999 Agreement on "Disposals of the Canadian Entitlement Within the U.S. for 4/1/98 Through 9/15/2024."

During the period 1 August 2002 through 31 March 2003, the Canadian Entitlement to downstream power benefits resulting from the operation of Mica was sold to CSPE. In accordance with the CEEA dated 13 August 1964, CSPE exchanged with BPA the rights to the Canadian Entitlement in return for delivery of a fixed schedule of capacity and energy to the CSPE participants based on the 1964 estimates of the Canadian Entitlement. CSPE sales were terminated in their entirety at midnight on 31 March 2003. The following graph compares the historic Canadian Entitlement computation from the DDPB studies to the amount sold under the CEEA contract.



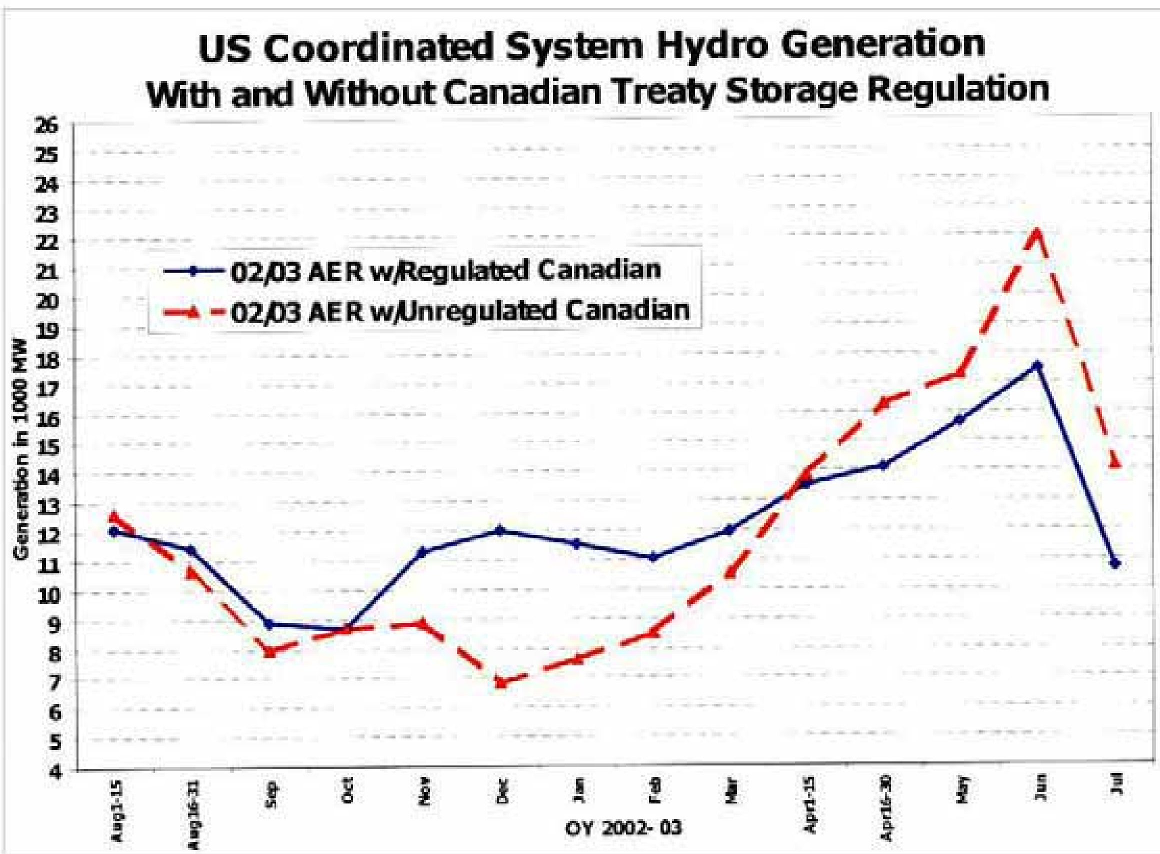
In accordance with the CEEA, dated 13 August 1964, and the Canadian Entitlement Allocation Extension Agreement, dated April 1997, the U.S. Entity granted permission for the non-federal downstream U.S. parties to make use of the U.S. one-half share of the Treaty downstream power benefits (U.S. Entitlement).

Power Generation and other Accomplishments

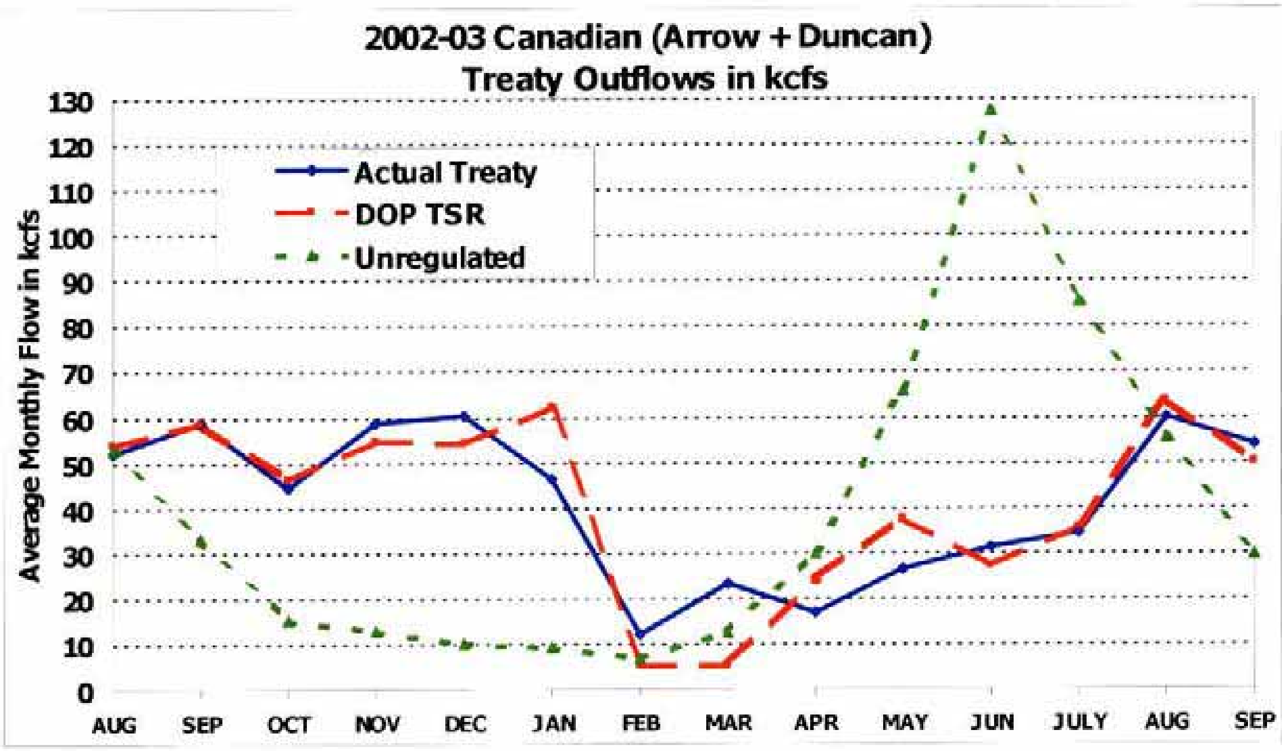
At the beginning of the 2002-2003 operating year, the TSR storage level for Canadian storage was only 91.8 percent full, and the actual Canadian storage was nearly the same at

91.3 percent full. Due to the below full starting storage contents the hydro system continued to draft proportionally well below the ORC through January 2003 in order to create the firm load carrying capability determined in the critical period studies. During February through July the coordinated system recovered to the ORC, with the exception of Mica, which was limited by target and minimum flow requirements. Actual Canadian storage on 31 July 2003 reached 88.7 percent full, slightly below the TSR storage level for Canadian storage of 89.6 percent full.

Actual U.S. power benefits from the operation of Treaty storage are unknown and can only be roughly estimated. Treaty storage has such a large impact on the U.S. system operation that its absence would significantly affect operating procedures, nonpower requirements, loads and resources, and market conditions, thus making any benefit analysis highly speculative. The following graph shows a rough estimate of the average monthly impact on downstream U.S. power generation during the 2002-2003 operating year, with and without the regulation of Canadian Treaty storage, based on the PNCA AER that includes minimum flow and spill requirements for U.S. fishery objectives. The increase in annual U.S. power generation due to the operation of Canadian storage, as measured by the PNCA AER, was 463 aMW.



Based on the authority from the 2002-2003 and 2003-2004 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 white fish spawning and the downstream migration of salmon. The following graph shows the difference in Arrow plus Duncan average monthly regulated outflows between the DOP TSR and the actual Treaty flows due to these agreements. The unregulated streamflow is also shown for comparison purposes.



As of 30 September 2002, the sum of Canadian Treaty storage was approximately on the DOP TSR. Treaty storage was operated near DOP TSR levels through November. During this period water from the Libby/Treaty swap was returned by the end of October, Canada exercised provisional draft and return under the LCA through November, and Duncan was provisionally drafted under the Duncan-Kootenay Agreement. Treaty storage was drafted approximately 489.32 hm^3 (200 ksfd) below DOP TSR levels in December through a combination of Duncan provisional draft under terms of the Duncan-Kootenay Agreement, LCA provisional draft, and Arrow draft under the Arrow-Grand Coulee Operating Agreement.

Beginning in mid-December, Arrow's actual discharge was reduced to about 45,000 cfs and Canada and the U.S. agreed to shape flow from January through July to meet multiple system requirements and fishery needs. From late January through late March, Arrow's actual discharge was maintained between 566.34 m^3/s (20,000 cfs) and 849.50 m^3/s (30,000 cfs) to protect whitefish in accordance with the Agreement on Operation of Canadian Treaty Storage. This operation lead to a draft of Treaty storage to about 1100.97 hm^3 (450 ksfd) below the DOP TSR level. Beginning in April, Arrow actual flows were reduced to 424.75 m^3/s (15,000 cfs) to balance the needs of B.C. trout spawning, U.S. fisheries needs, and system load requirements. The first TSR in April 2003 showed considerably higher Treaty contents than expected with the result that, at the end of April, Treaty storage was 611.65 hm^3 (250 ksfd) below the TSR level. Treaty projects refilled to TSR levels in May and remained near TSR contents through most of July.

Canada exercised provisional draft under the LCA in late July and September ending September near 56 ksfd below the DOP TSR.

TABLES

Table 1: 2003 Unregulated Runoff Volume Forecasts

Million of Acre-feet

First of Month Forecast	Most Probable 1 April through 31 August Forecast in Maf Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	1.70	20.3	9.72	4.86	69.8
February	1.74	18.69	9.26	4.66	65.3
March	1.71	17.57	8.84	4.18	63.7
April	1.82	19.67	9.81	4.96	72.4
May	1.87	20.54	10.35	5.22	77.8
June	1.88	20.15	10.48	5.11	76.8
Actual	1.89	20.07	10.4	5.08	93.8

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

Table 1M: 2003 Unregulated Runoff Volume Forecasts

Cubic Kilometers

Most Probable 1 April through 31 August Forecast in km^3

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.10	25.04	11.99	5.99	86.1
February	2.15	23.05	11.42	5.75	80.5
March	2.11	21.67	10.90	5.16	78.6
April	2.24	24.26	12.10	6.12	89.3
May	2.31	25.34	12.77	6.44	96.0
June	2.31	24.78	12.89	6.30	94.7
Actual	2.33	24.76	12.83	6.27	115.7

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

Table 2: 2003 Variable Refill Curve Mica Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			8049.0	7674.2	7364.7	7781.0	7745.8	6237.5
PROBABLE DATE-31JULY INFLOW, KSFD	**		4058.0	3869.0	3713.0	3922.9	3905.1	3144.7
95% FORECAST ERROR FOR DATE, KSFD			653.0	510.4	465.4	444.5	360.5	360.5
95% CONF.DATE-31JULY INFLOW, KSFD	1/		3405.0	3358.6	3247.6	3478.3	3544.6	2784.2
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		3405.0					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		7800.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		2778.6					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		2902.8					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2458.0					
JAN31 ORC, FT	7/		2439.0					
BASE ECC, FT	8/	2439.0						
LOWER LIMIT, FT		2403.1						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.6	97.6				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		3323.3	3277.9				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		7800.0	8000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		2559.3	2599.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		2765.2	2850.3				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2455.3	2458.9				
FEB28 ORC, FT	7/		2439.1	2439.1				
BASE ECC, FT	8/	2439.1						
LOWER LIMIT, FT		2399.9						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.1	95.1	97.4			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		3238.1	3194.0	3163.2			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		14600.0	15000.0	15000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		2316.4	2351.0	2351.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		2607.5	2686.2	2717.0			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2452.1	2453.7	2454.3			
MAR31 ORC, FT	7/		2436.0	2436.0	2436.0			
BASE ECC, FT	8/	2436.0						
LOWER LIMIT, FT		2394.9						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90.0	90.0	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		3064.5	3022.7	2994.3	3294.0		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		19500.0	20000.0	20000.0	14700.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1877.4	1901.0	1901.0	1651.2		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		2342.1	2407.5	2435.9	1886.4		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2446.7	2448.1	2448.7	2437.3		
APR30 ORC, FT	7/		2426.9	2426.9	2426.9	2426.9		
BASE ECC, FT	8/	2426.9						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		2438.0	2404.7	2380.5	2619.2	2818.0	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		20800.0	21000.0	21000.0	18900.0	16900.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		1272.9	1281.0	1281.0	1195.5	1116.4	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2364.1	2405.5	2429.7	2105.5	1827.6	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2447.2	2448.0	2448.5	2441.9	2436.0	
MAY31 ORC, FT	7/		2429.0	2429.0	2429.0	2429.0	2429.0	
BASE ECC, FT	8/	2429.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			35.5	35.5	36.3	37.3	39.4	49.5
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1208.8	1192.3	1178.9	1297.4	1396.6	1378.2
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		20900.0	21000.0	21000.0	20300.0	19600.0	19800.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		648.9	651.0	651.0	629.1	608.8	612.6
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2969.3	2987.9	3001.3	2860.9	2741.4	2763.6
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2459.3	2459.7	2459.9	2457.2	2454.8	2455.2
JUN30 ORC, FT	7/		2452.0	2452.0	2452.0	2452.0	2452.0	2452.0
BASE ECC, FT	8/	2452.0						
JUL 31 ORC, FT			2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

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

Table 2M: 2003 Variable Refill Curve Mica Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KM^3			9.93	9.47	9.08	9.60	9.55	7.69
PROBABLE DATE-31JULY INFLOW, HM^3	**		9928.30	9465.90	9084.23	9597.77	9554.22	7693.82
95% FORECAST ERROR FOR DATE, HM^3			1597.63	1248.74	1138.65	1087.51	882.00	882.00
95% CONF.DATE-31JULY INFLOW, HM^3	1/		8330.67	8217.15	7945.58	8510.01	8672.22	6811.82
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		8330.67					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		116.13					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/		6798.12					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		7101.99					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		749.20					
JAN31 ORC, M	7/		743.41					
BASE ECC, M	8/	743.41						
LOWER LIMIT, M		732.46						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.6	97.6				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		8108.85	8017.74				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		220.87	226.53				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		6261.58	6358.71				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		6765.34	6973.54				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		748.38	749.47				
FEB28 ORC, M	7/		743.44	743.44				
BASE ECC, M	8/	743.44						
LOWER LIMIT, M		731.49						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.1	95.1	97.4			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		7922.34	7814.44	7739.09			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		413.43	424.75	424.75			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		5667.30	5751.96	5751.96			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		6379.51	6572.06	6647.41			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		747.40	747.89	748.07			
MAR31 ORC, M	7/		742.49	742.49	742.49			
BASE ECC, M	8/	742.49						
LOWER LIMIT, M		729.69						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90.0	90.0	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		7497.61	7395.34	7325.85	8059.10		
MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		552.18	556.34	556.34	416.26		
MIN MAY1-JUL31 OUTFLOW, HM^3	4/		4593.25	4650.99	4650.99	4039.83		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		5730.18	5890.19	5959.67	4615.27		
VRC APR30 RESERVOIR CONTENT, METERS	6/		745.75	746.18	746.36	742.89		
APR30 ORC, M	7/		739.72	739.72	739.72	739.72		
BASE ECC, M	8/	739.72						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		5964.81	5883.34	5343.41	6408.13	6894.52	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		588.99	594.65	594.65	535.19	478.55	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		3114.28	3134.09	3134.09	2924.91	2731.38	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		5784.01	5885.30	5944.50	5151.32	4471.41	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		745.91	746.15	746.30	744.29	742.49	
MAY31 ORC, M	7/		740.36	740.36	740.36	740.36	740.36	
BASE ECC, M	8/	740.36						
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/		2957.45	2917.08	2884.30	3174.22	3416.92	3371.90
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		591.82	594.65	594.65	574.83	555.01	560.67
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		1587.60	1592.74	1592.74	1539.16	1489.49	1498.79
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		7264.69	7310.20	7342.98	6999.48	6707.11	6761.42
VRC JUN30 RESERVOIR CONTENT, METERS	6/		749.59	749.72	749.78	748.95	748.22	748.34
JUN30 ORC, M	7/		747.37	747.37	747.37	747.37	747.370	747.37
BASE ECC, M	8/	747.37						
JUL 31 ORC, M			752.89	752.89	752.89	752.89	752.89	752.89

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (8634.54 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: 2003 Variable Refill Curve Arrow Reservoir

		INITIAL	JAN 1 Total	FEB 1 Total	MAR 1 Total	APR 1 Total	MAY 1 Total	JUN 1 Total
PROBABLE DATE-31JULY INFLOW, KAF			17772.2	16354.0	15322.5	16296.4	15733.3	11878.6
& IN KSFD	**		8960.0	8245.0	7725.0	8216.0	7932.1	5988.7
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/		7726.6	7257.7	6899.8	7500.4	7430.4	5487.0
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		7726.6					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		5032.7					
UPSTREAM DISCHARGE, KSFD	4/		1544.8					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		2430.5					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1425.7					
JAN31 ORC, FT	7/		1425.7					
BASE ECC, FT	8/	1426.5						
LOWER LIMIT, FT		1385.9						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.5	97.5				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		7533.4	7076.3				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		4622.0	4648.0				
UPSTREAM DISCHARGE, KSFD	4/		1556.2	1556.2				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		2224.4	2707.5				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1422.2	1430.2				
FEB28 ORC, FT	7/		1422.2	1425.7				
BASE ECC, FT	8/	1425.7						
LOWER LIMIT, FT		1382.7						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.4	94.4	96.9			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		7293.9	6851.3	6685.9			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		4167.3	4183.0	4183.0			
UPSTREAM DISCHARGE, KSFD	4/		1704.4	1704.4	1704.4			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		2157.4	2615.7	2781.1			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1421.0	1428.7	1431.5			
MAR31 ORC, FT	7/		1421.0	1421.7	1421.7			
BASE ECC, FT	8/	1421.7						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.5	87.5	89.8	92.6		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		6760.8	6350.5	6196.0	6945.4		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		3547.8	3553.0	3553.0	3498.2		
UPSTREAM DISCHARGE, KSFD	4/		2126.0	2126.0	2126.0	2126.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		2492.6	2908.1	3062.6	2258.4		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1426.7	1433.5	1436.0	1422.8		
APR30 ORC, FT	7/		1416.3	1416.3	1416.3	1416.3		
BASE ECC, FT	8/	1416.3						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.5	65.5	67.2	69.3	74.9	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		5060.9	4753.8	4636.7	5197.8	5565.4	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		2685.0	2685.0	2685.0	2685.0	2685.0	
UPSTREAM DISCHARGE, KSFD	4/		2031.1	2031.1	2031.1	2031.1	2031.1	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		3234.8	3541.9	3579.6	3097.9	2730.3	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1438.7	1438.8	1444.0	1436.5	1430.6	
MAY31 ORC, FT	7/		1426.9	1426.9	1426.9	1426.9	1426.9	
BASE ECC, FT	8/	1426.9						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.3	30.3	31.1	32.1	34.7	46.3
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		2341.2	2199.1	2145.8	2407.6	2578.4	2540.5
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		1395.0	1395.0	1395.0	1395.0	1395.0	1395.0
UPSTREAM DISCHARGE, KSFD	4/		975.8	975.8	975.8	975.8	975.8	975.8
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3579.6	3579.6	3579.6	3542.8	3372.0	3409.9
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1444.0	1444.0	1444.0	1443.4	1440.8	1441.4
JUN30 ORC, FT	7/		1440.0	1440.0	1440.0	1440.0	1440.0	1440.0
BASE ECC, FT	8/	1440.0						
JUL 31 ECC, FT			1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ CUMMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS
4/ UPSTREAM DISCHARGE REQUIREMENT. 5/ FULL CONTENT (3579.6 KSFD) MINUS 2/ PLUS 3/ MINUS /4.
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: 2003 Variable Refill Curve Arrow Reservoir

		INITIAL	JAN 1 Total	FEB 1 Total	MAR 1 Total	APR 1 Total	MAY 1 Total	JUN 1 Total
PROBABLE DATE-31JULY INFLOW, KM^3			21.9	20.2	18.9	20.1	19.4	14.7
PROBABLE DATE-31JULY INFLOW, HM^3			21926	200176	18903	20105	19410	14655
95% FORECAST ERROR FOR DATE, IN HM^3			3021.8	2418.9	2021.7	1753.2	1229.2	1229.2
95% CONF.DATE-31JULY INFLOW, HM^3	1/		18903.90	17756.69	16881.05	18350.48	18179.22	13424.49
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		18903.90					
MIN FEB1-JUL31 OUTFLOW, HM^3	3/		12313.00					
UPSTREAM DISCHARGE, HM^3	4/		3779.51					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		5946.46					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		434.55					
JAN31 ORC, M	7/		434.80					
BASE ECC, M	8/	434.80						
LOWER LIMIT, M		422.42						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.5	97.5				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		18431.22	17312.88				
MIN MAR1-JUL31 OUTFLOW, HM^3	3/		11308.19	11371.80				
UPSTREAM DISCHARGE, HM^3	4/		3807.40	3807.40				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		5442.22	6624.17				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		433.49	435.93				
FEB28 ORC, M	7/		433.49	435.93				
BASE ECC, M	8/	435.93						
LOWER LIMIT, M		421.45						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.4	94.4	96.9			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		17845.26	16762.39	16357.72			
MIN APR1-JUL31 OUTFLOW, HM^3	3/		10195.72	10234.13	10234.13			
UPSTREAM DISCHARGE, HM^3	4/		4169.99	4169.99	4169.99			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		5278.29	6399.57	6804.24			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		433.12	435.47	436.32			
MAR31 ORC, M	7/		433.33	433.33	433.33			
BASE ECC, M	8/	433.33						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.5	87.5	89.8	92.6		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		16540.97	15537.13	15159.13	16992.62		
MIN MAY1-JUL31 OUTFLOW, HM^3	3/		8680.05	8692.77	8692.77	8558.70		
UPSTREAM DISCHARGE, HM^3	4/		5201.47	5201.47	5201.47	5201.47		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		6098.40	7114.96	7492.96	5525.40		
VRC APR30 RESERVOIR CONTENT, METERS	6/		434.86	436.93	437.69	433.67		
APR30 ORC, M	7/		431.69	431.69	431.69	431.69		
BASE ECC, M	8/	431.69						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.5	65.5	67.2	69.3	74.9	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		12382.00	11630.65	11344.15	12716.94	13616.31	
MIN JUN1-JUL31 OUTFLOW, HM^3	3/		6569.12	6569.12	6569.12	6569.12	6569.12	
UPSTREAM DISCHARGE, HM^3	4/		4969.29	4969.29	4969.29	4969.29	4969.29	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		7914.26	8665.61	8757.85	7579.32	6679.95	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		438.52	438.55	440.13	437.85	436.05	
MAY31 ORC, M	7/		434.92	434.92	434.92	434.92	434.92	
BASE ECC, M	8/	434.92						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL. 46.3			30.3	30.3	31.1	32.1	34.7	
ASSUMED JUL1-JUL31 INFLOW, KSFD 6215.59	2/		5727.98	5380.32	5249.91	5890.43	6308.31	
MIN JUL1-JUL31 OUTFLOW, KSFD 3413.01	3/		3413.01	3413.01	3413.01	3413.01	3413.01	
UPSTREAM DISCHARGE, KSFD 2387.89	4/		2387.89	2387.89	2387.89	2387.89	2387.89	
VRC JUN30 RESERVOIR CONTENT, KSFD 6215.59	5/		8757.85	8757.85	8757.85	8667.81	6308.31	
VRC JUN30 RESERVOIR CONTENT, METERS 439.34	6/		440.13	440.13	440.13	439.95	439.16	
JUN30 ORC, M 438.91	7/		438.91	438.91	438.91	438.91	438.91	
BASE ECC, M	8/	438.91						
JUL 31 ECC, 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/ FULL CONTENT (8757.85 HM^3) MINUS 2/ PLUS 3/ MINUS /4.
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: 2003 Variable Refill Curve Duncan Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			1471.8	1503.5	1469.8	1500.9	1443.7	1098.2
& IN KSFD	**		742.0	758.0	741.0	756.7	727.9	553.6
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/		623.6	649.1	643.5	668.6	654.6	480.3
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		623.6					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		232.6					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		314.8					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1844.8					
JAN31 ORC, FT	7/		1841.1					
BASE ECC, FT	8/	1841.1						
LOWER LIMIT, FT		1806.3						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		609.9	634.8				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		229.8	230.8				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		325.7	301.8				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1846.3	1843.1				
FEB28 ORC, FT	7/		1831.1	1828.5				
BASE ECC, FT	8/	1840.9						
LOWER LIMIT, FT		1799.3						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		594.3	618.5	626.8			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		226.7	227.7	227.7			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		338.2	315.0	306.7			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1847.9	1844.9	1843.7			
MAR31 ORC, FT	7/		1831.1	1828.5	1830.7			
BASE ECC, FT	8/	1836.9						
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/		556.3	579.0	586.2	625.1		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		1000.0	1000.0	1000.0	800.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		213.5	214.2	214.2	206.5		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		363.0	341.0	333.8	287.2		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1857.1	1848.4	1847.3	1841.2		
APR30 ORC, FT	7/		1831.1	1828.5	1830.7	1822.6		
BASE ECC, FT	8/	1834.7						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		421.6	438.8	444.6	474.0	496.2	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		2800.0	2800.0	2800.0	2800.0	2800.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		183.0	183.2	183.2	181.0	179.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		467.2	450.2	444.4	412.8	388.6	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1864.2	1862.1	1861.3	1857.4	1854.4	
MAY31 ORC, FT	7/		1850.0	1850.0	1850.0	1850.0	1850.0	
BASE ECC, FT	8/	1850.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			31.7	31.7	32.4	33.3	35.6	46.9
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		197.7	205.7	208.5	222.6	233.0	225.3
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		3200.0	3200.0	3200.0	3100.0	3100.0	3100.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		99.0	99.2	99.2	97.0	95.0	95.4
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		607.1	599.3	596.5	580.2	567.8	575.9
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1880.7	1879.9	1879.5	1877.6	1876.1	1877.1
JUN30 ORC, FT	7/		1873.0	1873.0	1873.0	1873.0	1873.0	1873.0
BASE ECC, FT	8/	1873.0						
JUL 31 ECC, FT			1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

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

Table 4M: 2003 Variable Refill Curve Duncan Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KM^3			1.42	1.85	1.81	1.85	1.78	1.35
& IN HM^3	**		1815.38	1854.52	1812.93	1851.34	1780.88	1354.44
95% FORECAST ERROR FOR DATE, IN HM^3			289.68	266.43	238.54	215.55	179.34	179.34
95% CONF.DATE-31JULY INFLOW, HM^3	1/		1525.70	1588.09	1574.39	1635.80	1601.54	1175.10
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		1525.70					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		2.83					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/		569.08					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		770.19					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		562.30					
JAN31 ORC, M	7/		561.17					
BASE ECC, M	8/	561.17						
LOWER LIMIT, M		550.56						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		1492.18	1553.10				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		2.83	2.83				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		562.23	564.68				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		796.86	738.38				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		562.75	561.78				
FEB28 ORC, M	7/		558.12	557.33				
BASE ECC, M	8/	561.11						
LOWER LIMIT, M		548.43						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		1454.01	1513.22	1533.53			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		2.83	2.83	2.83			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		554.64	557.09	557.09			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		827.44	770.68	750.37			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		563.24	562.33	561.96			
MAR31 ORC, M	7/		558.12	557.33	558.00			
BASE ECC, M	8/	559.89						
LOWER LIMIT, M		547.15						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.2	89.2	91.1	93.5		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		1361.04	1416.58	1434.20	1529.37		
MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		28.32	28.32	28.32	22.65		
MIN MAY1-JUL31 OUTFLOW, HM^3	4/		522.35	524.06	505.22	505.22		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		888.12	834.29	816.68	702.66		
VRC APR30 RESERVOIR CONTENT, METERS	6/		556.04	563.39	563.06	561.20		
APR30 ORC, M	7/		558.12	557.33	558.00	557.53		
BASE ECC, M	8/	559.22						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		1031.49	1073.57	1087.76	1159.69	1214.00	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		79.29	79.29	79.29	79.29	79.29	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		447.73	448.22	448.22	442.83	437.94	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		1143.05	1101.46	1087.27	1009.96	950.75	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		568.21	567.57	567.32	566.14	565.22	
MAY31 ORC, M	7/		563.88	563.88	563.88	563.88	563.88	
BASE ECC, M	8/	563.88						
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/		483.69	503.27	510.12	544.61	570.06	551.22
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		90.61	90.61	90.61	90.61	90.61	90.61
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		242.21	242.70	242.70	237.32	232.43	233.41
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		1485.33	1466.25	1459.40	1419.52	1389.18	1409.00
VRC JUN30 RESERVOIR CONTENT, METERS	6/		573.24	572.99	572.87	572.29	571.84	572.14
JUN30 ORC, M	7/		570.89	570.89	570.89	570.89	570.89	570.89
BASE ECC, M	8/	570.89						
JUL 31 ECC, M			576.68	576.68	576.68	576.68	576.68	576.68

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (1726.81 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: 2003 Variable Refill Curve Libby Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			4906.5	4689.5	4215.0	4952.0	5192.0	5107.3
PROBABLE DATE-31JULY INFLOW, KSFD			2473.7	2364.3	2125.1	2496.6	2617.6	2574.9
95% FORECAST ERROR FOR DATE, KSFD			886.8	606.4	552.5	503.7	474.5	367.5
OBSERVED JAN1-DATE INFLOW, IN KSFD			0.0	76.1	139.1	240.5	489.5	1113.7
95% CONF.DATE-31JULY INFLOW, KSFD	1/		1586.9	1681.7	1433.4	1752.5	1653.6	1093.7
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			97.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		1538.7					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		967.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1938.8					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2433.2					
JAN31 ORC, FT	7/		2413.2					
BASE ECC, FT	9/	2413.2						
LOWER LIMIT, FT		2381.5						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.2	97.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		1494.6	1633.7				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		855.0	857.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1870.9	1733.8				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2430.0	2423.1				
FEB28 ORC, FT	7/		2410.5	2410.5				
BASE ECC, FT	9/	2410.5						
LOWER LIMIT, FT		2336.7						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.8	93.7	96.4			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		1441.1	1575.1	1382.1			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0	4000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		731.0	733.0	733.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1800.4	1668.4	1861.4			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2426.4	2419.8	2429.5			
MAR31 ORC, FT	7/		2407.5	2407.5	2407.5			
BASE ECC, FT	9/	2407.5						
LOWER LIMIT, FT		2292.8						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.7	85.3	87.8	93.9		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		1312.4	1434.4	1258.5	1645.9		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0	4000.0	4000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		611.0	613.0	613.0	591.4		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1809.1	1689.1	1865.0	1456.0		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2426.9	2420.9	2429.7	2408.4		
APR30 ORC, FT	7/		2406.5	2406.5	2406.5	2406.5		
BASE ECC, FT	9/	2406.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.3	57.0	58.7	62.8	66.9	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		877.2	958.9	841.4	1100.4	1105.4	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		6966.7	7000.0	7000.0	6646.7	6320.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		487.0	489.0	489.0	467.4	447.5	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2120.2	2040.6	2158.1	1877.6	1852.6	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2441.7	2438.0	2443.4	2430.3	2429.0	
MAY31 ORC, FT	7/		2430.3	2430.3	2430.3	2430.3	2429.0	
BASE ECC, FT	9/	2430.3						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.6	20.2	20.8	22.3	23.7	35.5
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		311.0	340.0	298.3	390.1	391.9	387.7
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		8966.7	9000.0	9000.0	8646.7	8320.0	8380.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		278.0	279.0	279.0	268.0	257.9	259.8
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2477.4	2449.4	2491.2	2388.4	2376.5	2382.5
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2457.6	2456.3	2458.2	2453.7	2453.2	2453.4
JUN30 ORC, FT	7/		2453.8	2453.8	2453.8	2453.7	2453.2	2453.4
BASE ECC, FT	9/	2453.8						
JUL 31 ORC, FT			2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		98.7	101.0	97.3	96.4	98.2	100.0

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: 2003 Variable Refill Curve Libby Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KM^3			6.05	5.78	5.20	6.11	6.40	6.30
PROBABLE DATE-31JULY INFLOW, HM^3			6052.15	5784.50	5199.27	6108.18	6404.22	6299.75
95% FORECAST ERROR FOR DATE, HM^3			2169.64	1483.62	1351.75	1232.35	1160.91	899.13
OBSERVED JAN1-DATE INFLOW, IN HM^3			0.0	186.19	340.32	588.41	1197.61	2724.78
95% CONF.DATE-31JULY INFLOW, HM^3	1/		3882.51	4114.45	3506.96	4287.67	4045.70	2675.85
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			97.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		3764.58					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.27					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/		2365.86					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		4743.47					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		741.64					
JAN31 ORC, M	7/		735.54					
BASE ECC, M	9/	735.64						
LOWER LIMIT, M		725.88						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.2	97.1				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		3656.69	3997.01				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.27	113.27				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		2091.84	2096.74				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		4577.34	4241.92				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		740.66	738.56				
FEB28 ORC, M	7/		734.72	734.72				
BASE ECC, M	9/	734.72						
LOWER LIMIT, M		712.23						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.8	93.7	96.4			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		3525.80	3608.98	3381.45			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.27	113.27	113.27			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		1788.46	1793.36	1793.36			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		4404.86	4081.91	4554.10			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		739.57	737.56	740.51			
MAR31 ORC, M	7/		733.81	733.81	733.81			
BASE ECC, M	9/	733.81						
LOWER LIMIT, M		698.85						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.7	85.3	87.8	93.9		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		3210.92	3509.40	3079.05	4026.86		
MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.27	113.27	113.27	113.27		
MIN MAY1-JUL31 OUTFLOW, HM^3	4/		1494.87	1499.77	1499.77	1446.92		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		1809.1	1689.1	1865.0	1456.0		
VRC APR30 RESERVOIR CONTENT, METERS	6/		739.72	737.89	740.57	734.08		
APR30 ORC, M	7/		733.50	733.50	733.50	733.50		
BASE ECC, M	9/	733.50						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.3	57.0	58.7	62.8	66.9	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		2146.16	2346.04	2058.57	2692.24	2704.47	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		197.27	198.22	198.22	188.20	178.96	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		1191.49	1196.39	1196.39	1143.54	1094.85	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		5187.28	4992.53	5280.01	4593.74	4532.57	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		744.23	743.10	744.75	740.76	740.36	
MAY31 ORC, M	7/		740.76	740.76	740.76	740.76	740.36	
BASE ECC, M	9/	740.76						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.6	20.2	20.8	22.3	23.7	35.5
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		760.89	831.84	729.82	954.42	958.82	948.55
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		253.91	254.85	254.85	244.85	235.60	237.29
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		680.15	682.60	682.60	655.69	630.98	635.63
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		6061.21	5992.70	6094.97	5843.46	5814.34	5829.02
VRC JUN30 RESERVOIR CONTENT, METERS	6/		749.08	748.68	749.26	747.89	747.74	747.80
JUN30 ORC, M	7/		747.92	747.92	747.92	747.89	747.74	747.80
BASE ECC, M	9/	747.92						
JUL 31 ORC, M			749.50	749.50	749.50	749.50	749.50	749.50
JAN1-JUL31 FORECAST,-EARLYBIRD, KM^3	8/		121.75	124.58	120.02	118.91	121.13	123.35

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 (6142.19 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 OE ARC OR CRC1 IN DOP

Table 6: Computation of Initial Controlled Flow

Columbia River at The Dalles
1 May 2003

1 May Forecast of May – August Unregulated Runoff Volume, Maf		66.285
Less Estimated Depletions, Maf		1.500
Less Upstream Storage Corrections, Maf		17.794
Mica	5.746	
Arrow	3.600	
Duncan	1.373	
Libby	1.982	
Libby + Duncan Under Draft	0.000	
Hungry Horse	0.782	
Flathead Lake	0.500	
Noxon Rapids	0.000	
Pend Oreille Lake	0.500	
Grand Coulee	0.904	
Brownlee	0.134	
Dworshak	0.541	
John Day	0.232	
Total	17.794	
Forecast of Adjusted Residual Runoff Volume, Maf		48.491
Computed Initial Control Flow from Chart 1 of Flood Control Operation Plan, 1,000 cfs		301

Table 6M: Computation of Initial Controlled Flow

Columbia River at The Dalles
1 May 2003

1 May Forecast of May – August Unregulated Runoff Volume - km^3		81.76
Less Estimated Depletions, km^3		1.85
Less Upstream Storage Corrections, km^3		21.95
Mica	7.09	
Arrow	4.44	
Duncan	1.69	
Libby	2.44	
Libby + Duncan Under Draft	0.00	
Hungry Horse	0.96	
Flathead Lake	0.62	
Noxon Rapids	0.00	
Pend Oreille Lake	0.62	
Grand Coulee	1.12	
Brownlee	0.17	
Dworshak	.67	
John Day	0.29	
Total	21.95	
Forecast of Adjusted Residual Runoff Volume, km^3		59.81
Computed Initial Control Flow from Chart 1 of Flood Control Operation Plan, m^3/s		8,523

CHARTS

Chart 1: Seasonal Precipitation

Columbia River Basin
October 2002 – September 2003

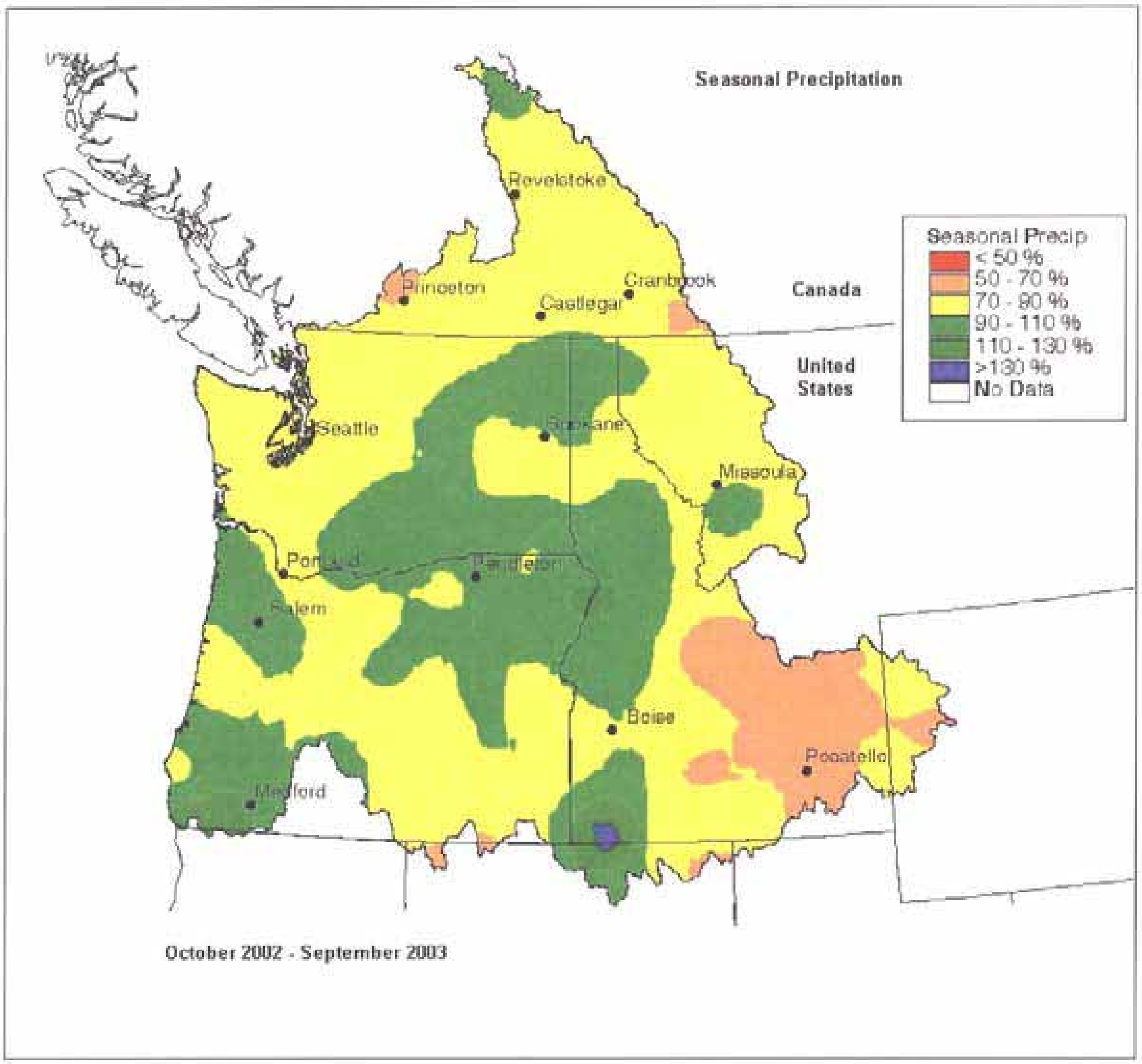
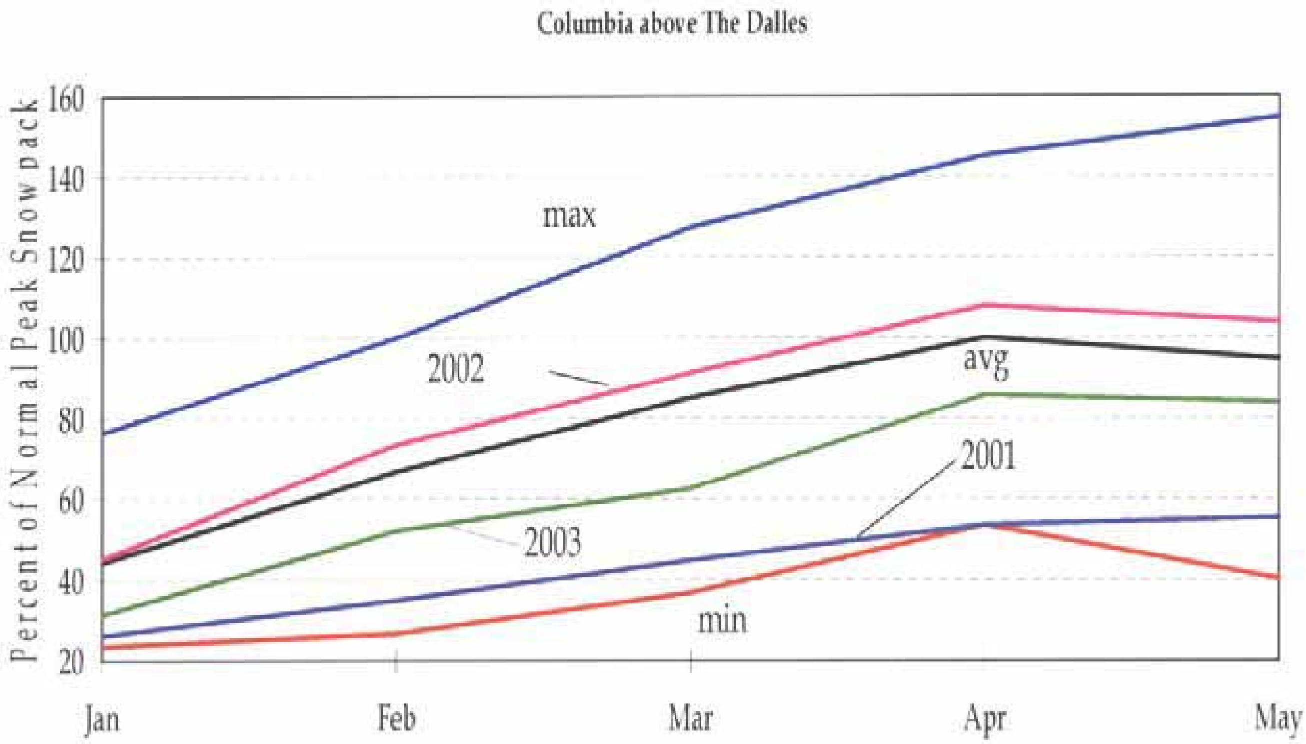


Chart 2: Columbia Basin Snowpack



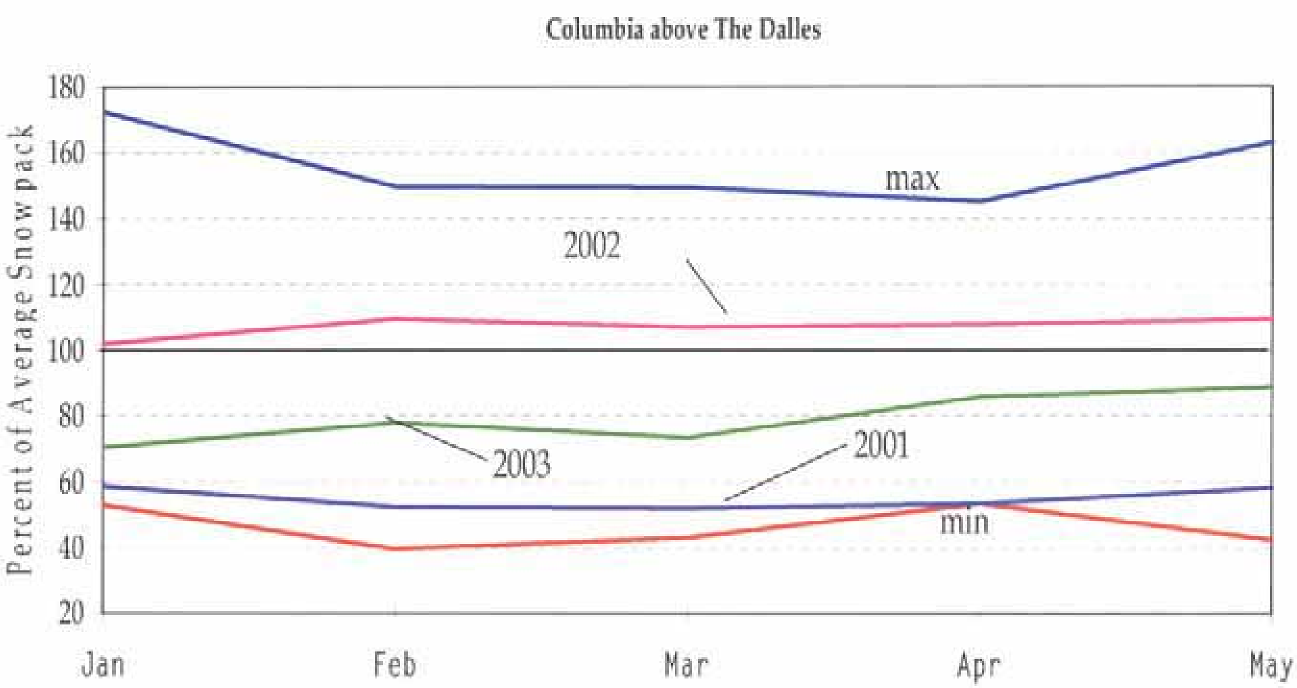


Chart 3: Accumulated Precipitation For WY 2003

At Primary Columbia River Basins

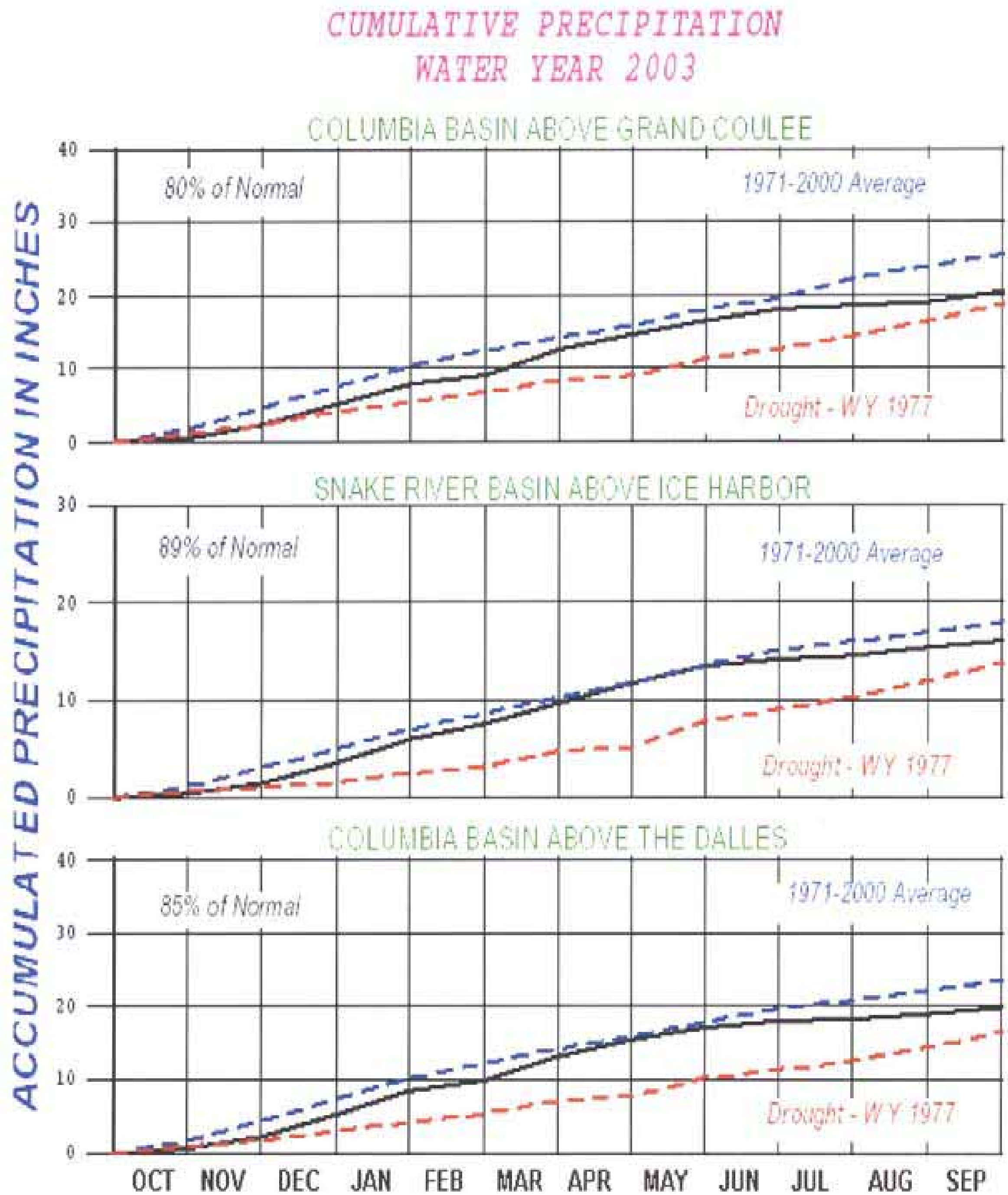


Chart 4: Pacific Northwest Monthly Temperature

Departures From Normal September 2003 – April 2003

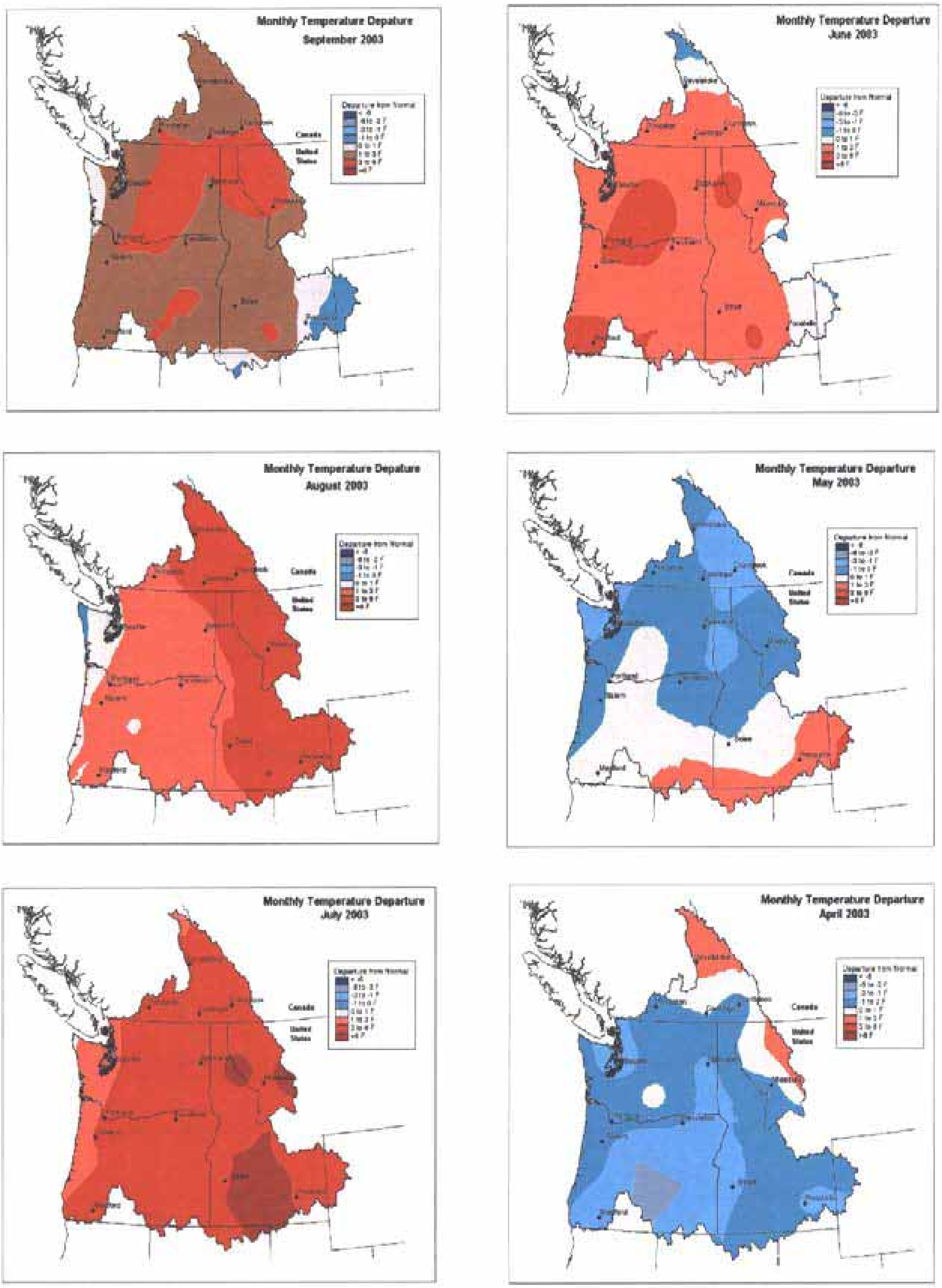
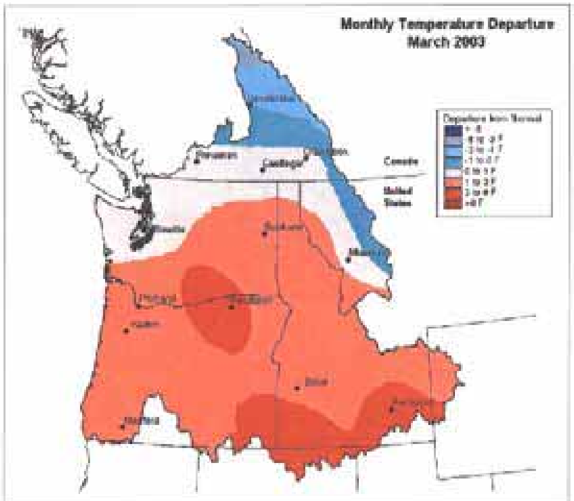
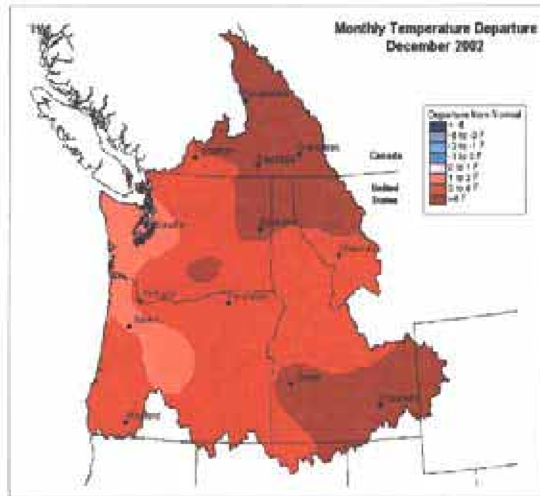
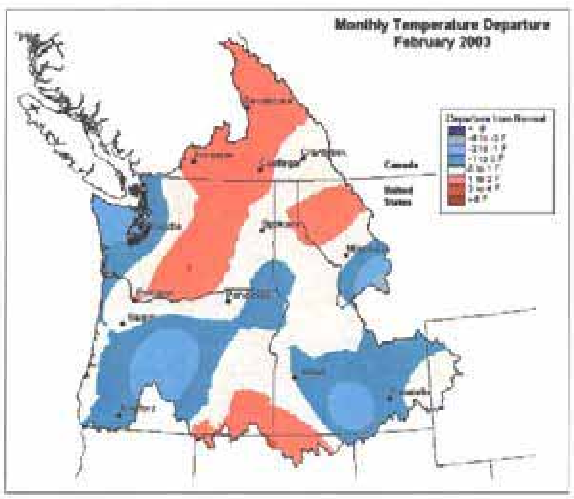


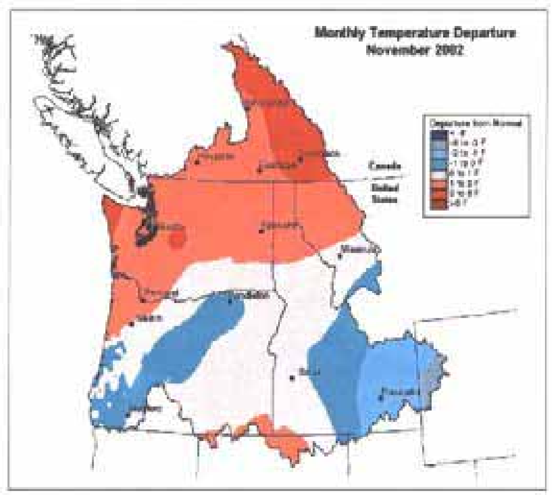
Chart 4: Pacific Northwest Monthly Temperature

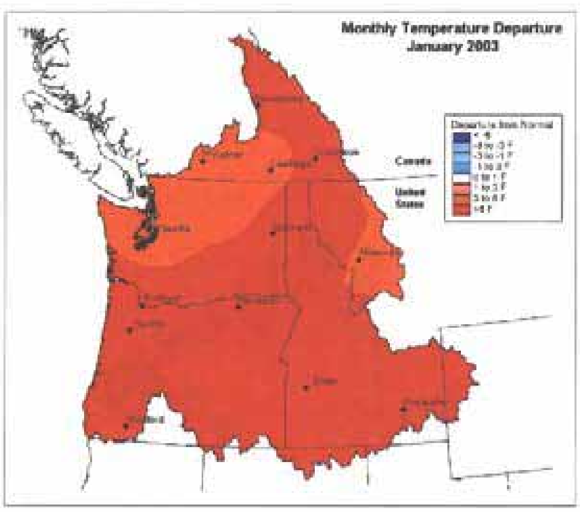
Departures From Normal March 2003 – October 2002











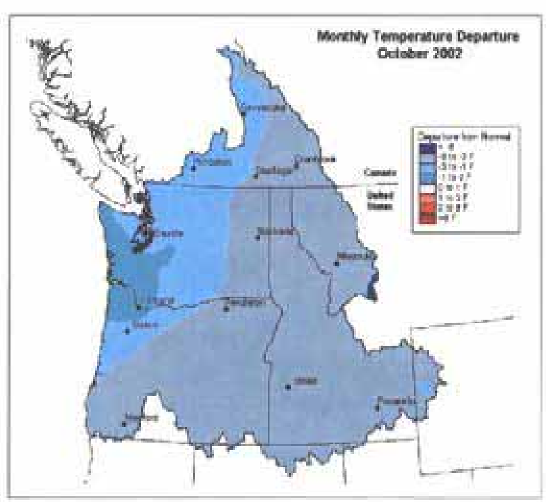
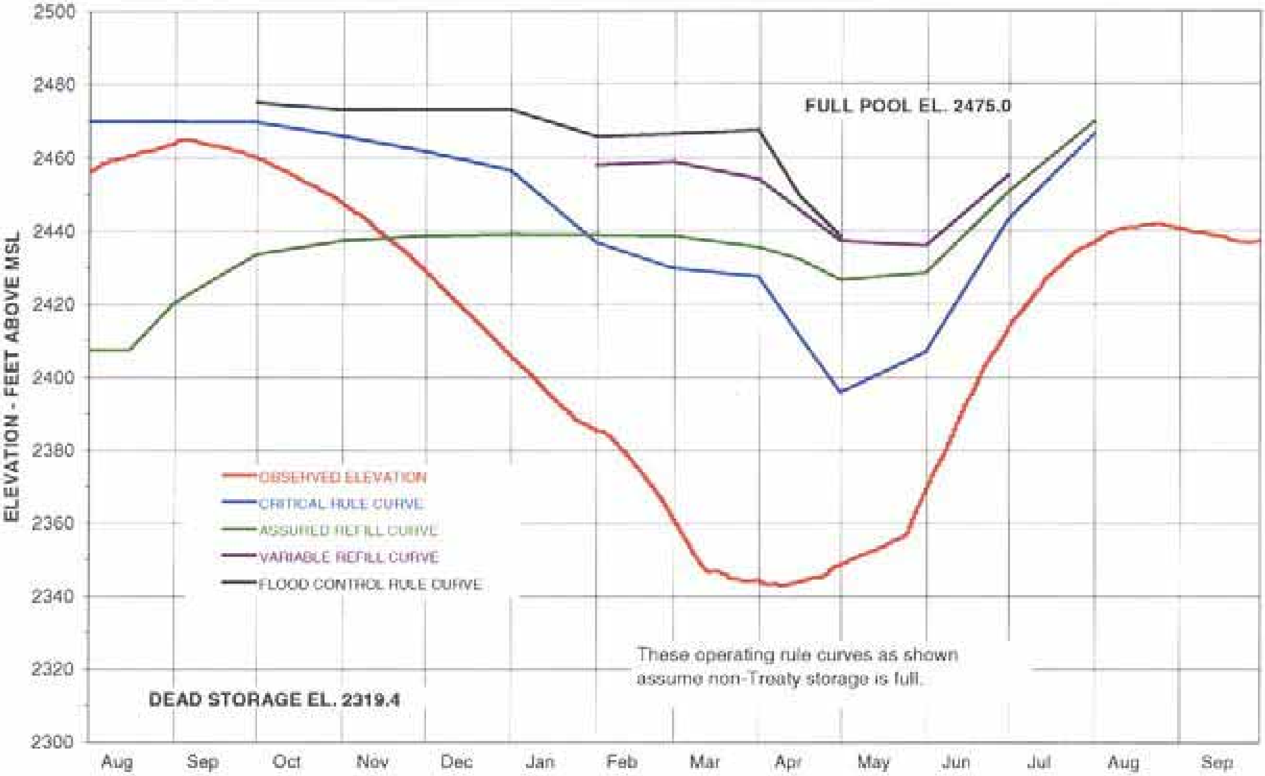


Chart 5: Regulation Of Mica

1 August 2002 – 31 September 2003



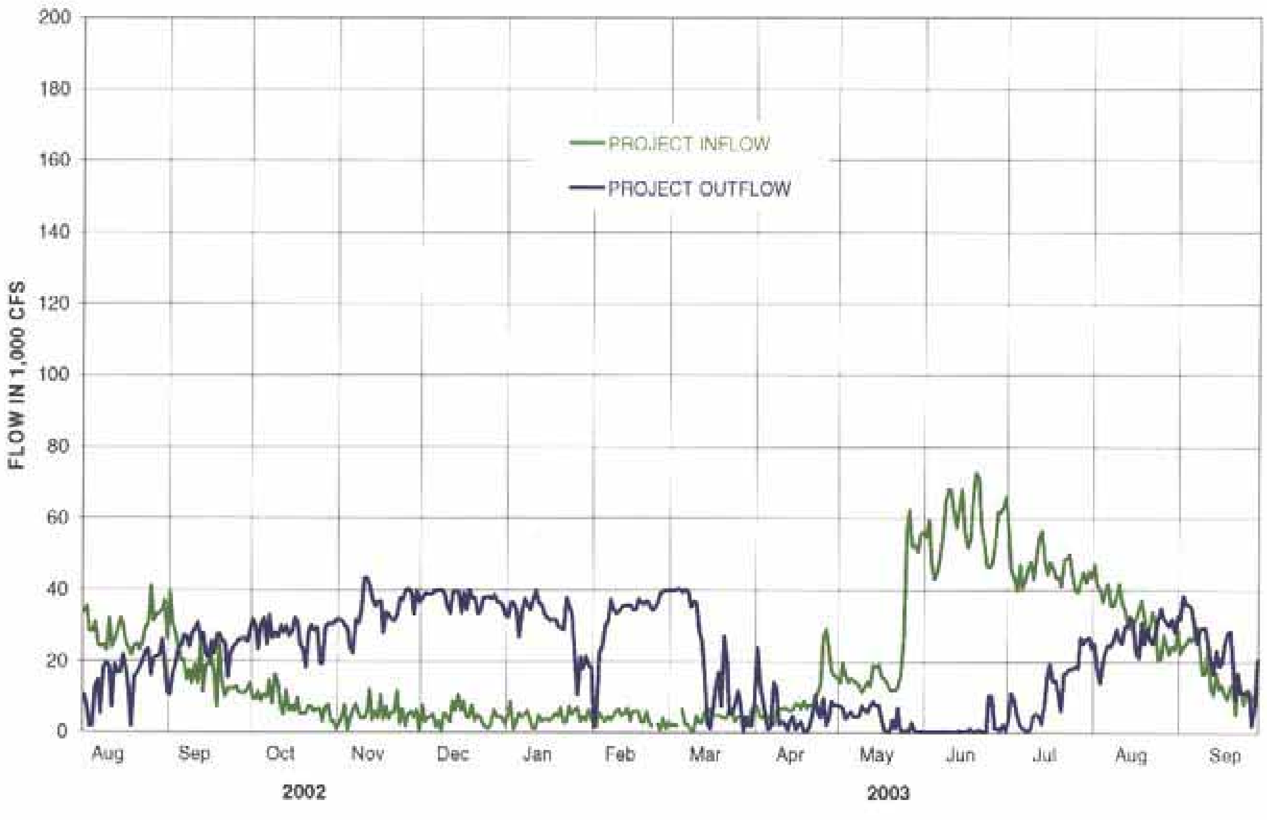
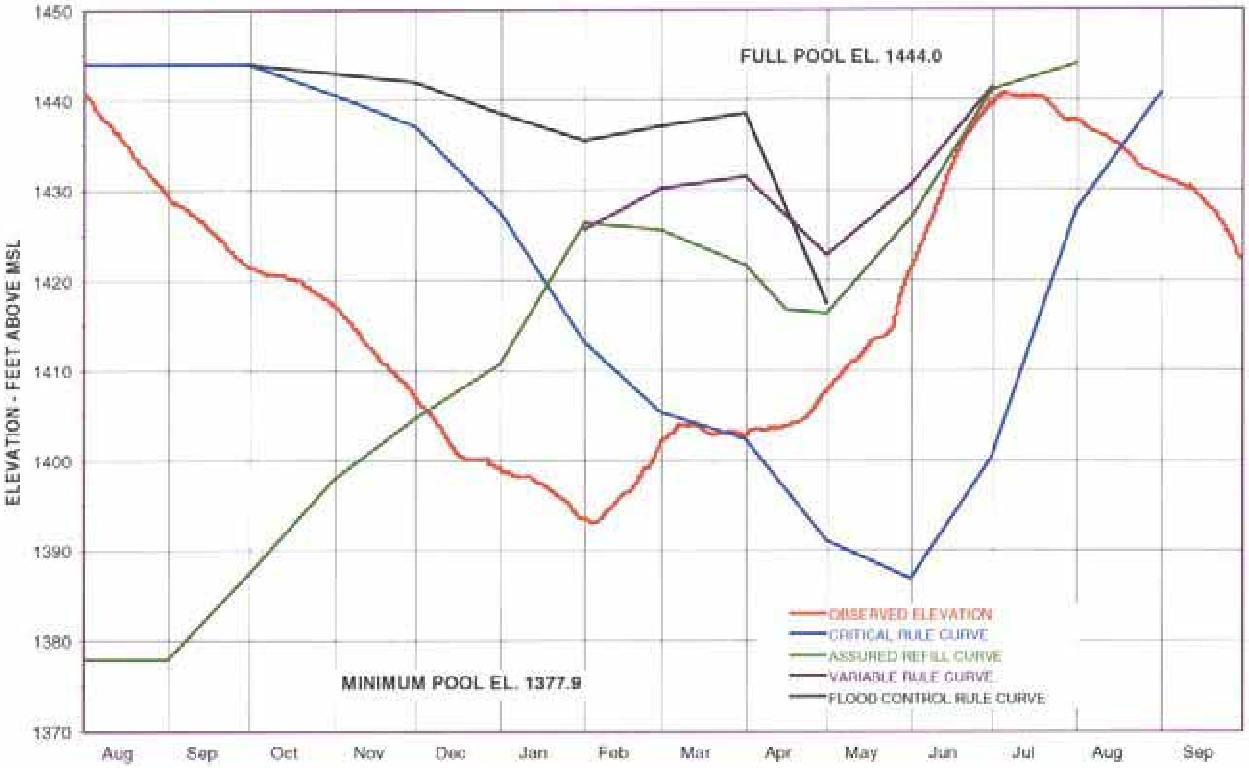


Chart 6: Regulation Of Arrow

1 August 2002 – 31 September 2003



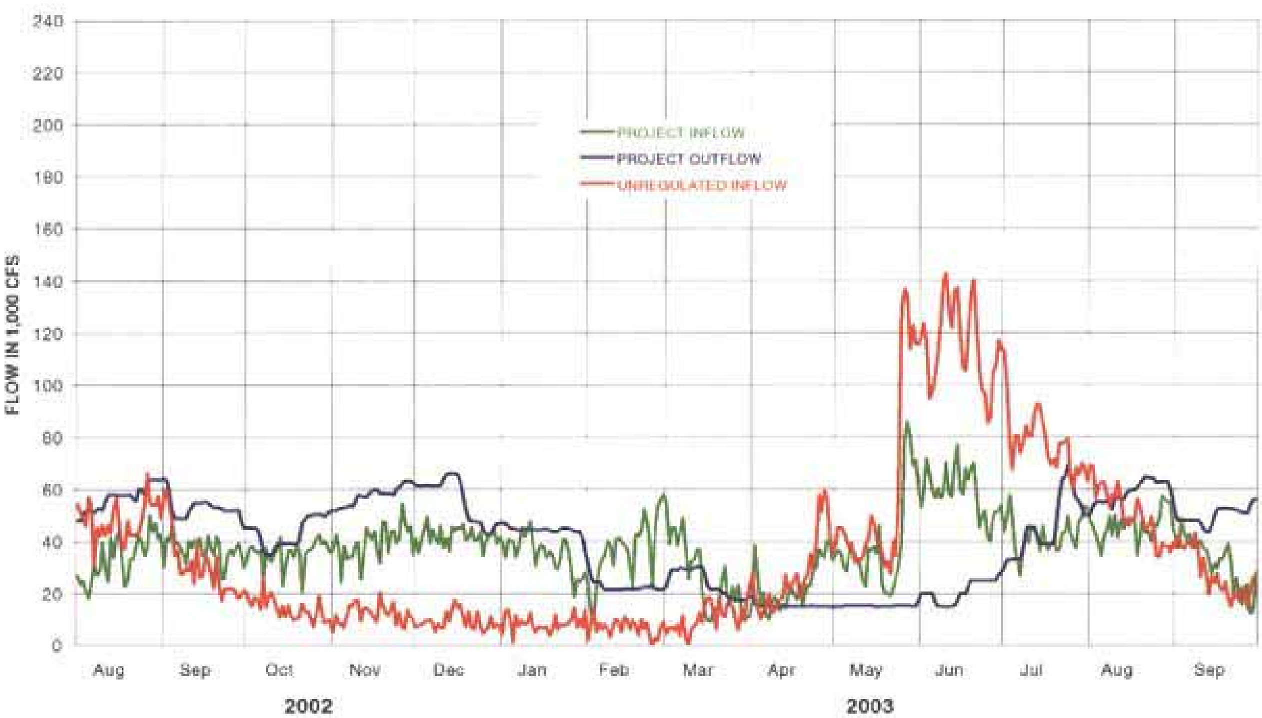
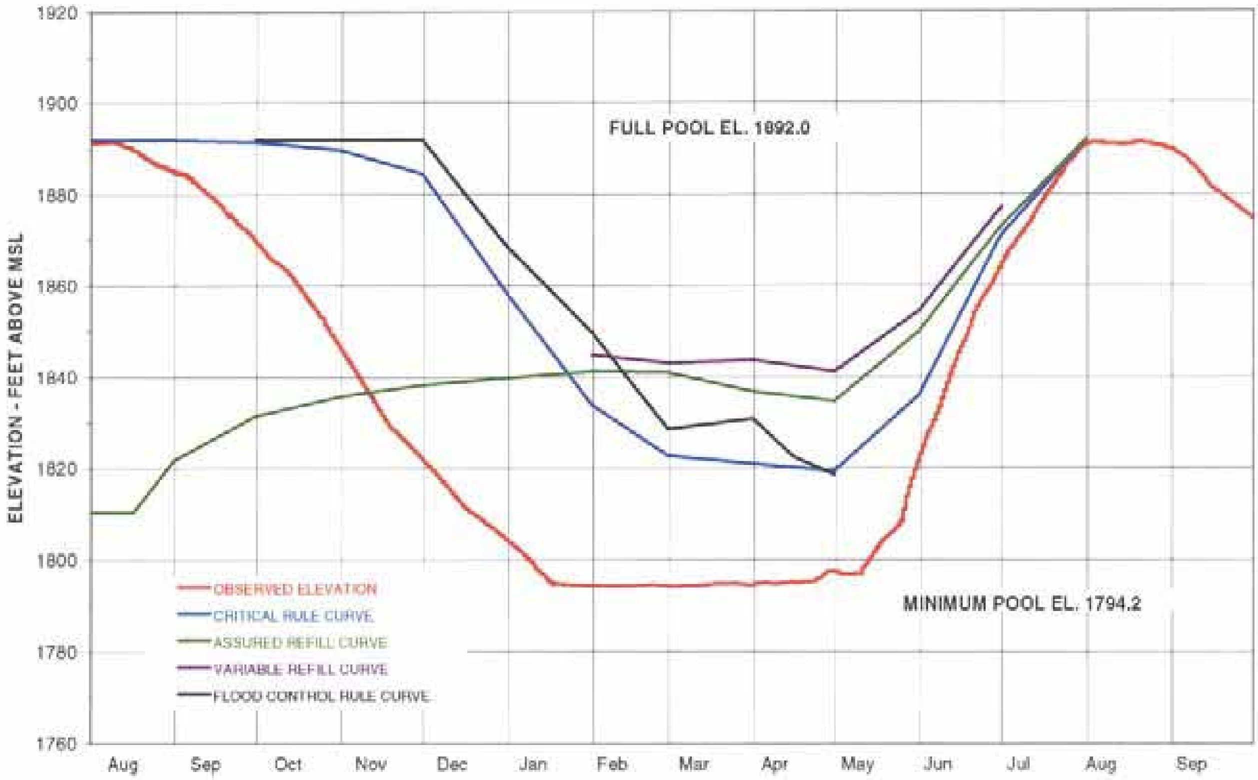


Chart 7: Regulation Of Duncan
1 August 2002 – 31 September 2003



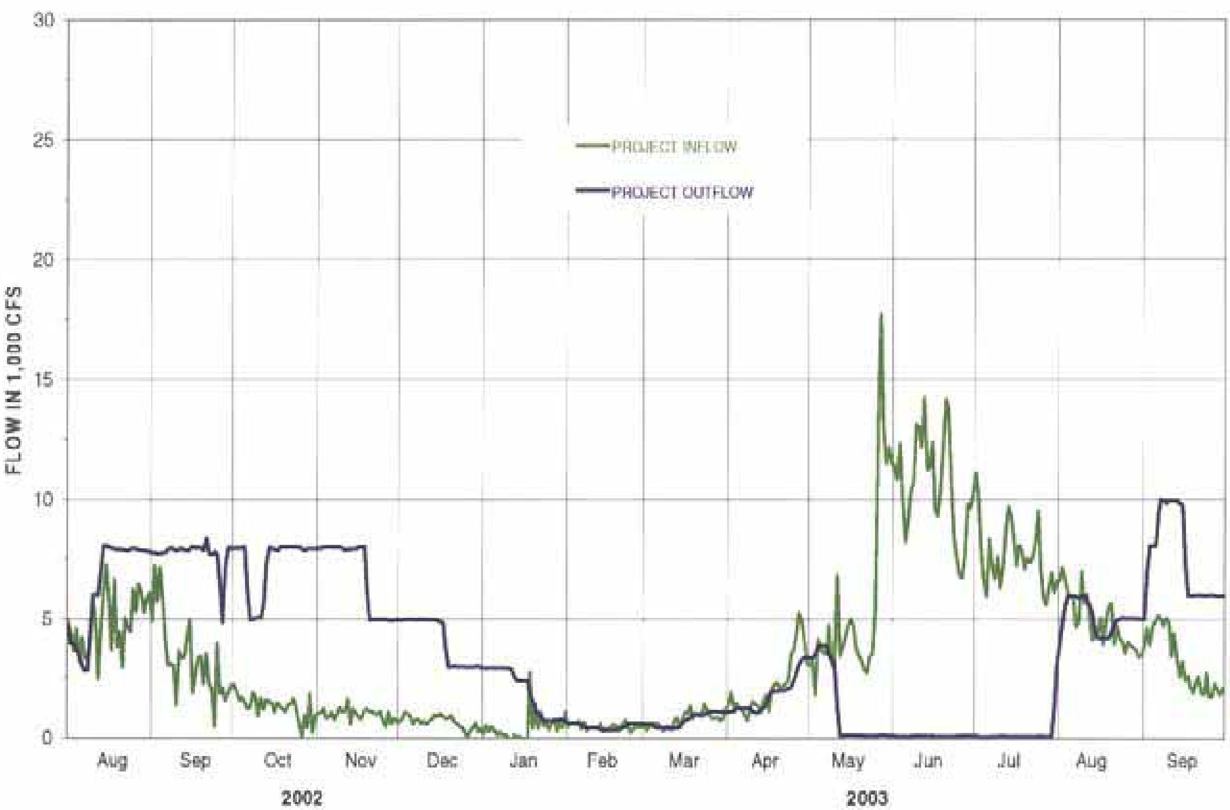


Chart 8: Regulation Of Libby

1 August 2002 – 31 September 2003

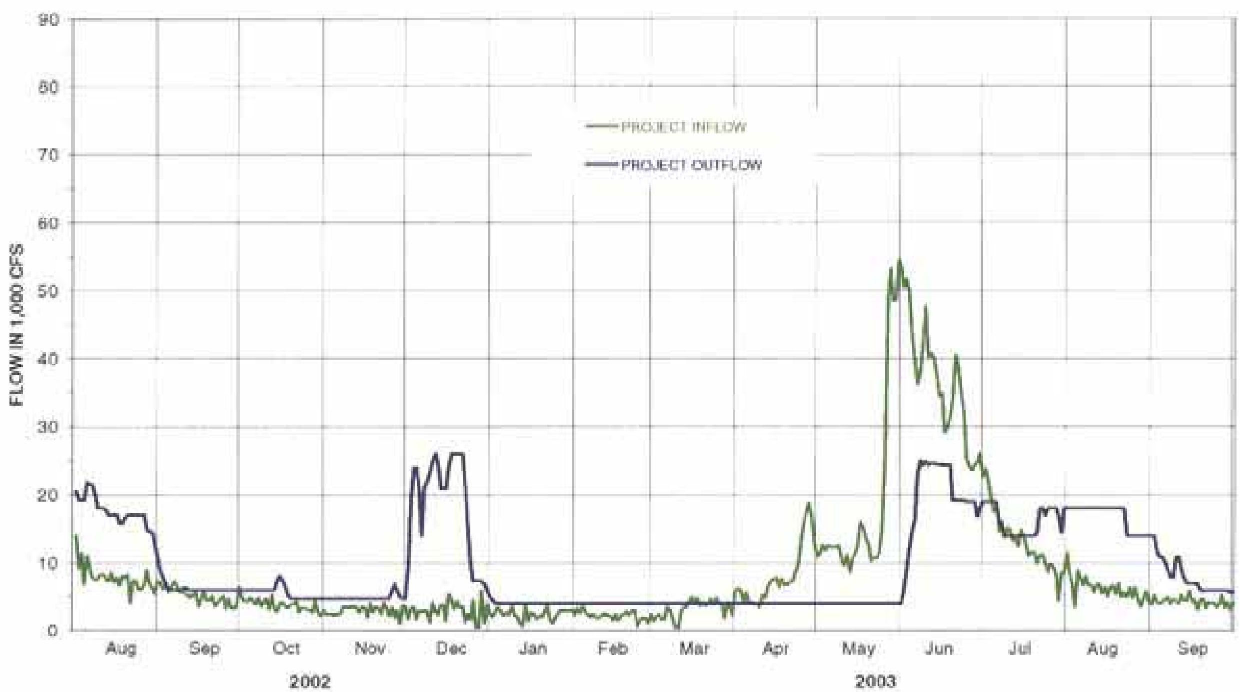


Chart 9: Regulation Of Kootenay Lake

1 August 2002 – 31 September 2003

Chart 10: Columbia River At Birchbank

1 August 2002 – 31 September 2003

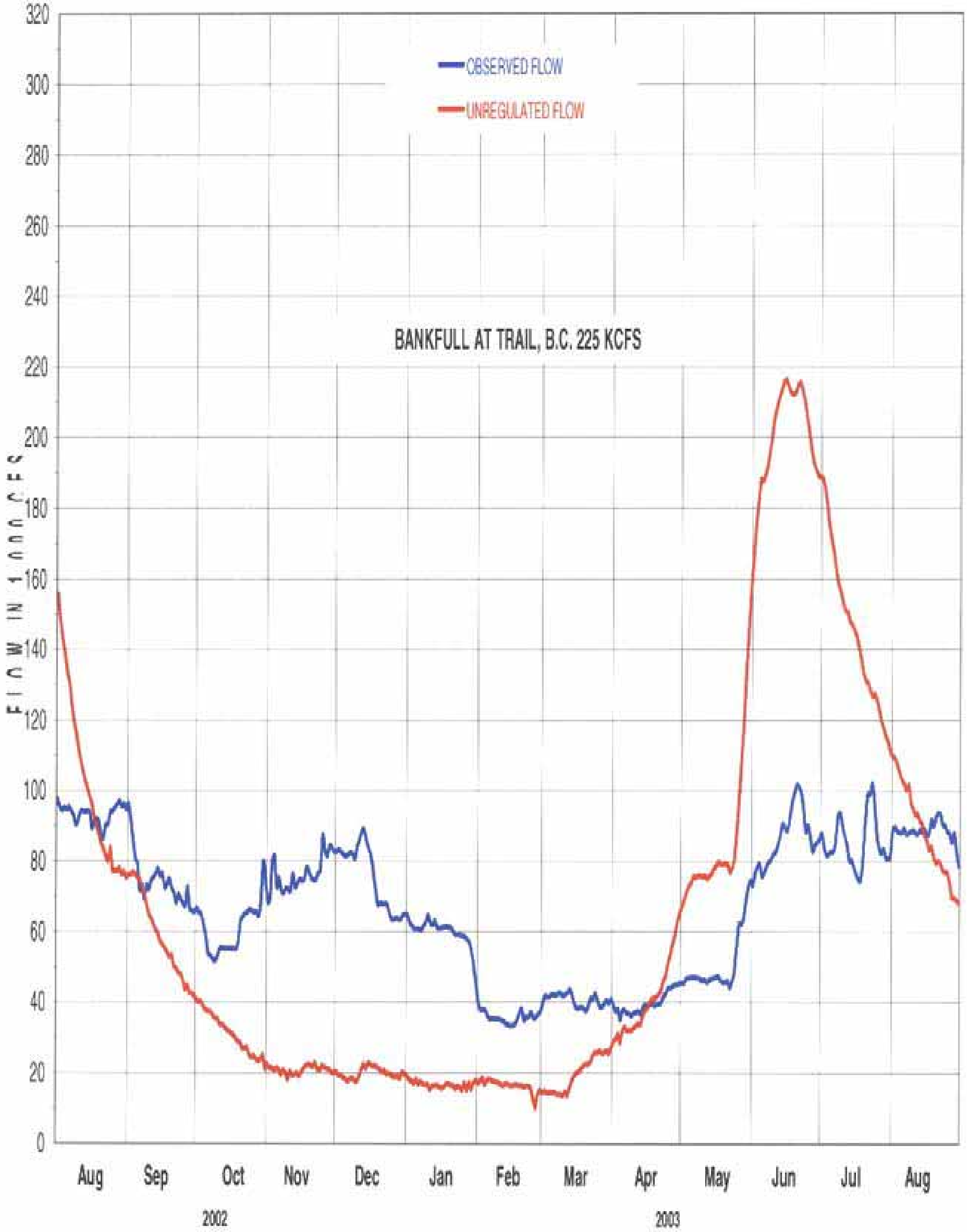


Chart 11: Regulation Of Grand Coulee

1 August 2002 – 31 August 2003

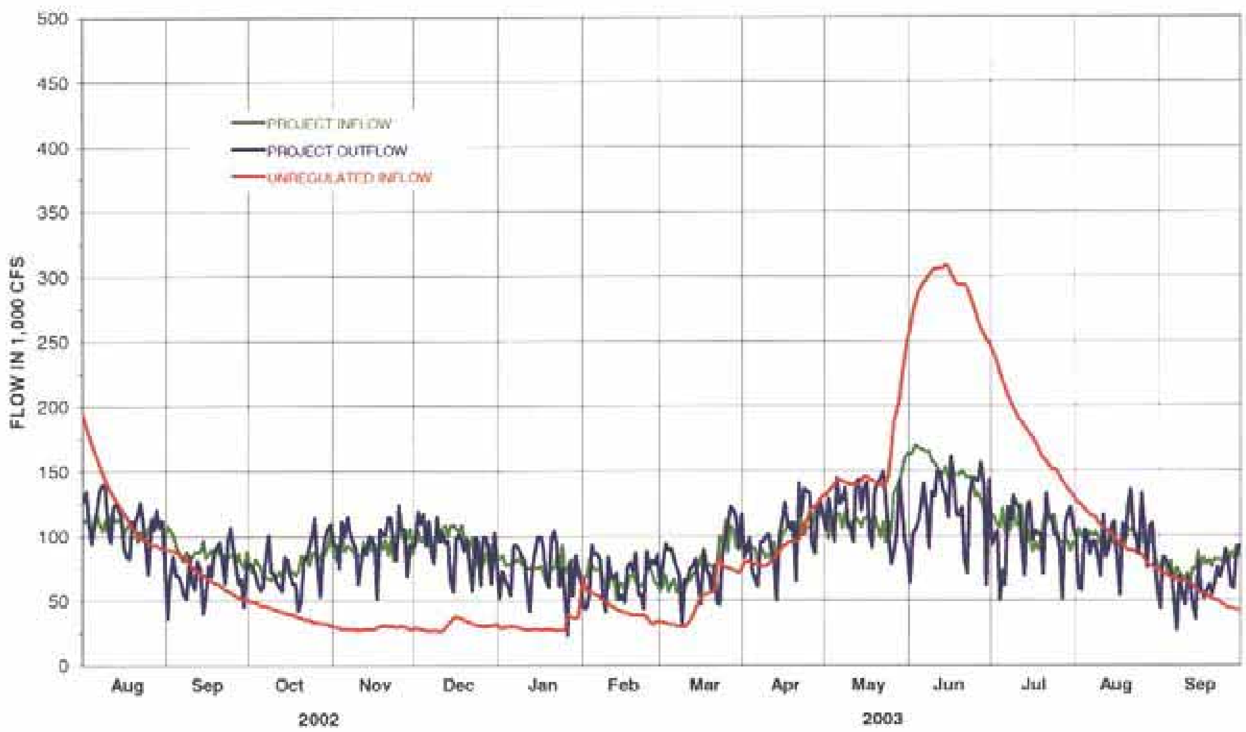


Chart 12: Columbia River At The Dalles

(Summary Hydrograph)
1 AUGUST 2002 – 30 SEPTEMBER 2003

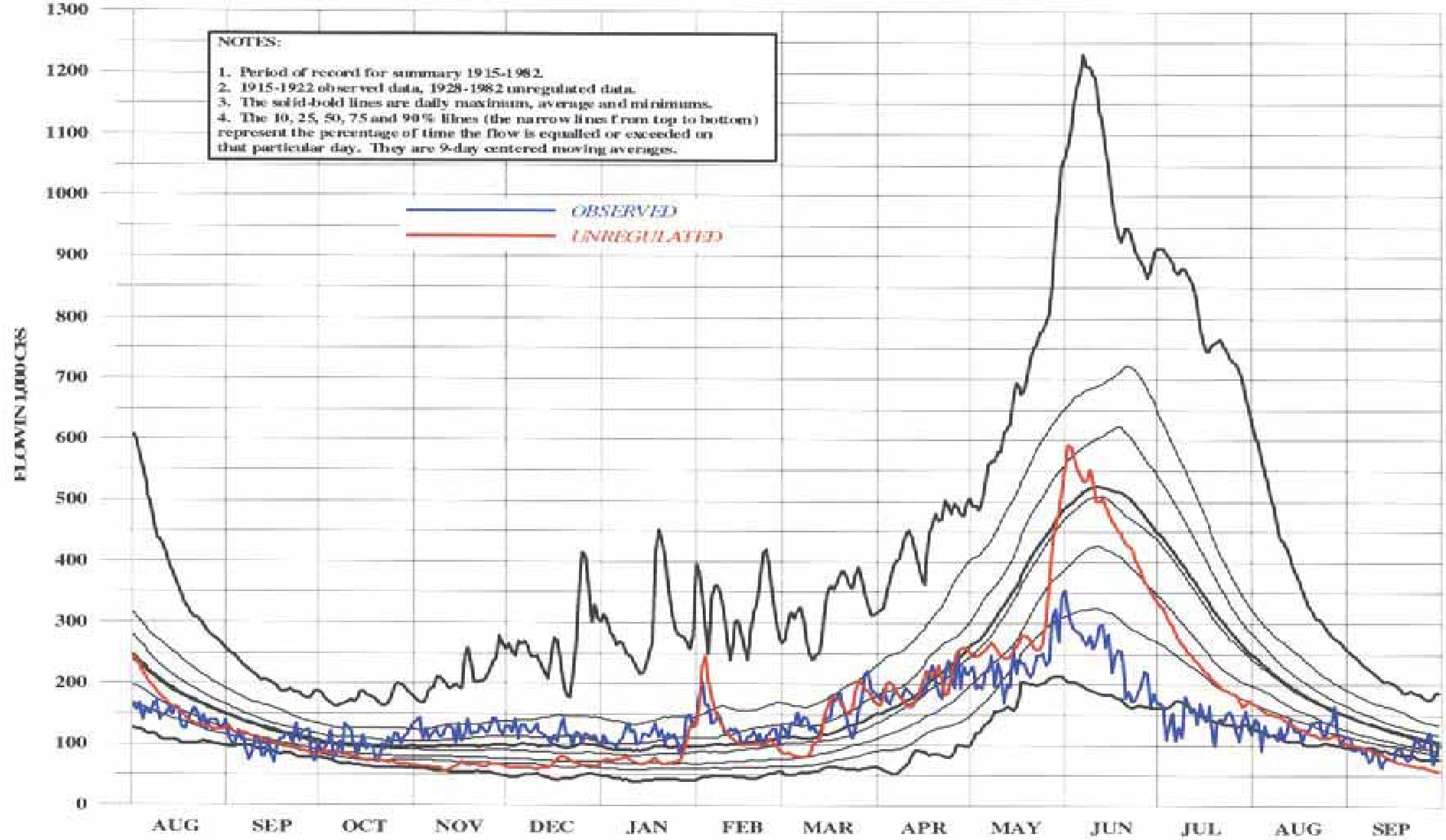


Chart 13: Columbia River At The Dalles
(Re-Regulation Plot)
1 April 2003 – 31 July 2003

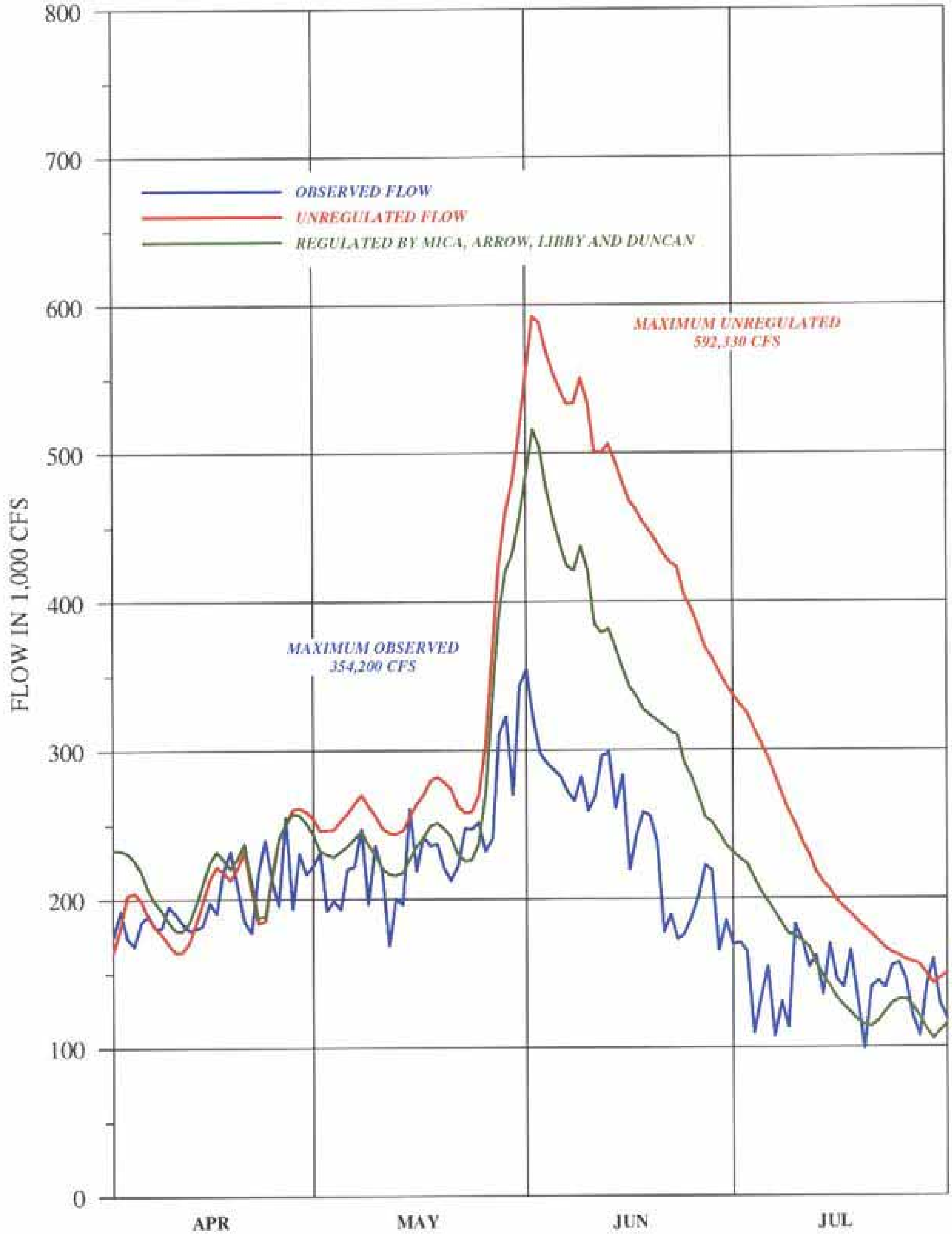


Chart 14: 2003 Relative Filling Arrow And Grand Coulee