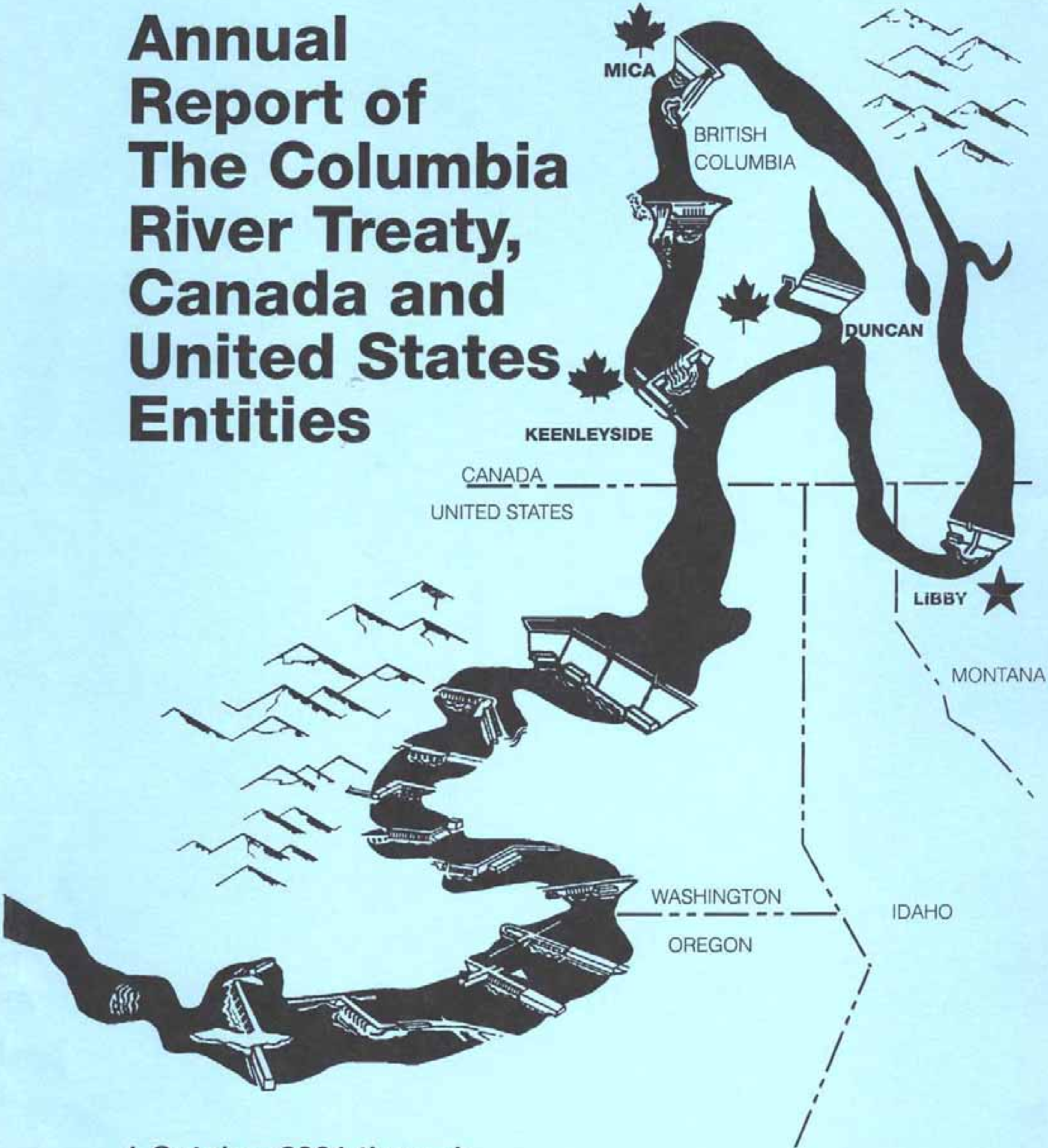
Annual Report of The Columbia River Treaty, Canada and United States Entities



1 October 2001 through
30 September 2002

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

FOR THE PERIOD
1 OCTOBER 2001 – 30 SEPTEMBER 2002

EXECUTIVE SUMMARY

General

The Canadian Treaty projects, Mica, Duncan, and Arrow were operated during the reporting period according to the 2001-02 and 2002-03 Detailed Operating Plans (DOP), the October 1999 Flood Control Operating Plan, and several supplemental operating agreements described below. Throughout the year, Libby was operated according to the 1999 Flood Control Operating Plan, the Libby Coordination Agreement (LCA) dated February 2000, and 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). During September through December 2001, Libby was also operated for power purposes according to the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER).

Entity Agreements

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

- Columbia River Treaty Entity Agreement Relating to Extension of the Expiration Date of the Non-Treaty Storage Agreement, signed 28 June 2002.
- Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for 1 August 2002 through 31 July 2003, signed 22 July 2002.

Operating Committee Agreements

Agreements approved by the Operating Committee include:

- Addendum to Columbia River Treaty Operating Committee Agreement on Operation of Summer Treaty Storage for 1 August 2001 through 31 March 2002, Bonneville Power Administration (BPA) Contract No. 01PB24335, signed 17 October 2001.
- Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Nonpower Uses for 1 January through 31 July 2002, signed 7 February 2002.
- Agreement among the Columbia River Treaty Operating Committee (CRTOC) and BPA and British Columbia Hydro and Power Authority (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, signed 30 August 2002.

In addition to the Operating Committee agreements listed here, BPA and B.C. Hydro under their Non-Treaty Storage Agreement (NTSA) executed an April-September storage-release verbal/e-mail agreement, a standardized May-June storage/July-August release agreement to benefit fisheries, and a Treaty Special Storage option under the NTSA which modified system operations for recreation, fisheries, and power purposes.

System Operation

Under the 2000 – 01 DOP, the Coordinated System operation is modeled similar to the Assured Operating Plan (AOP), without updating loads and U.S. fishery requirements. Due to the low water of 2000–01 the Coordinated System operation was well below the Operating Rule Curve (ORC) for the first part of the year. The Coordinated System recovered to the ORC in May through July, except for Mica which was limited by minimum flow requirements. Through April the system was in proportional draft as required to meet the established firm load carrying capability.

The 1 January 2002 water supply forecast (WSF) for the Columbia River at The Dalles for January through July was 123.4 cubic kilometers (km^3) (100.0 million acre-feet (Maf)), or 93 percent of the 1971-2000 average. Precipitation, which had been below normal throughout Water Year 2001, returned to normal by the fall of 2001. May precipitation came in well above normal, which caused the observed runoff at The Dalles to be higher than the forecasted volume. The unregulated runoff from January through July was 128.0 km^3 (103.8 Maf) at The Dalles, 97 percent of the 1971-2000 average. The unregulated runoff for 2002 peaked slightly later than normal with the bulk of the water coming off in June. The observed peak unregulated flow at The Dalles was 17,180 cubic meters per second (m^3/s) (606,800 cubic feet per second (cfs)) on 7 June 2002.

The Columbia River was operated to meet chum needs below Bonneville Dam from November 2001 through 8 May 2002. U.S. reservoirs were operated to target the 10 April flood control elevation per the NMFS 2000 BiOp for juvenile fish needs. For 2002 Libby Dam conducted an operation that focused on the Kootenai River white sturgeon larvae stage instead of the standard sturgeon pulsing operation. U.S. storage projects refilled by 31 July 2002. 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 292.1 average megawatts (aMW) at rates up to 782.6 MW during 1 August 2001 through 31 July 2002, and 293.1 aMW at rates up to 642.0 MW during 1 August 2002 through 30 September 2002. No Entitlement power was disposed directly in the U.S. during 1 August 2001 through 31 July 2002, 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."

The Canadian Entitlement resulting from the operation of Mica reservoir during the reporting period was sold to Columbia Storage Power Exchange (CSPE, a consortium of 41 northwest utilities), in accordance with the Canadian Entitlement Purchase Agreement (CEPA), dated 13 August 1964. 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 95 aMW at rates up to 187 MW during 1 August 2001 through 31 March 2002, and 93 aMW at rates up to 167 MW during 1 April 2002 through 31 July 2002.

Treaty Project Operation

Due to the low water supply experienced during 2001, actual Canadian Treaty storage (Canadian storage) began the 2001-02 operating year well below full, reaching only 12.6 km^3 (10.2 Maf) or 65.7 percent full on 31 July 2001. Actual Canadian storage drafted to 1.2 km^3 (0.97 Maf) on 31 March 2002 and refilled to 17.5 km^3 (14.2 Maf) or 91.3 percent full on 31 July 2002.

Mica reservoir reached a maximum elevation of 742.14 m (2,434.8 feet) on 3 September 2001, 13.24 m (40.2 feet) below full pool. The reservoir reached its lowest level for the year, elevation 712.40 m (2,337.2 feet), on 12 April 2002. This level set a new record low for the Mica reservoir. The reservoir recovered substantially during 2002, reaching a maximum elevation of 751.36 m (2465.1 feet) on 3 September 2002, 3.02 m (9.9 feet) below full pool.

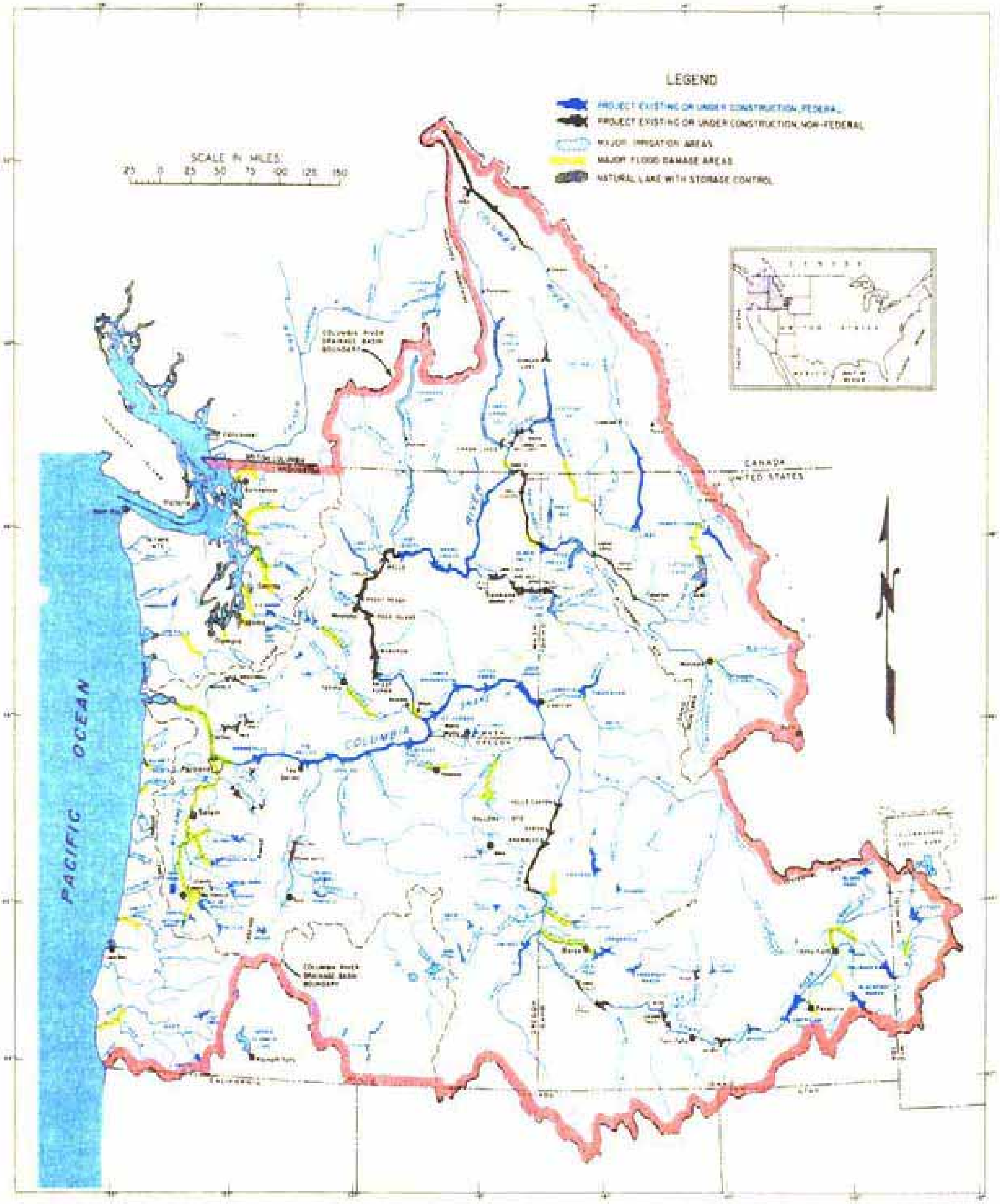
The Arrow reservoir reached a maximum elevation of 430.42 m (1,412.1 feet) on 3 July 2001. The Reservoir reached its lowest level of the year at elevation 422.52 m (1,386.2 feet) on

14 January 2002. During the period 21 December 2001 to 20 January 2002, Arrow outflows were held at 934.6 m^3/s (33,000 cfs) to maintain low river levels during the whitefish spawning period. During April and May 2002, 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, and to help meet non-power requirements in the United States. The Arrow reservoir reached its highest level on 17 August 2002 at elevation 439.92 m (1,443.3 feet), 0.21 m (0.7 feet) below full pool.

Duncan reservoir did not refill during 2001, reaching a maximum elevation of 571.72 m (1,875.7 feet) on 4 August 2001, 4.97 m (16.3 feet) below full pool. From August 2001 through December 2001, Duncan discharge was used to supplement inflow into Kootenay Lake. By 31 December 2001, the reservoir had drafted to 550.93 m (1,807.5 feet), 4.06 m (13.3 feet) above empty pool elevation. Duncan reservoir reached empty on 13 March 2002. With above average inflow during the 2002 freshet, the reservoir refilled to full pool elevation of 576.68 m (1,892.0 feet) by 15 July 2002.

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
kaf	Thousand acre feet
km^3	Cubic Kilometers
ksfd	Thousand second-foot-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
PNCA	Pacific Northwest Coordination Agreement
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
VRC	Variable Rule Curve
WSF	Water Supply Forecast

I INTRODUCTION

This annual Columbia River Treaty Entity Report is for the 2002 Water Year, 1 October 2001 through 30 September 2002. 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 2001 through 31 July 2002. The power and flood control effects downstream in Canada and the United States of America (U.S.) are described. This report is the thirty-sixth of a series of annual reports covering the period since the ratification of the Columbia River Treaty in September 1964.

Duncan, Arrow, and Mica reservoirs in Canada and Libby reservoir in the U.S. were constructed under the provisions of the Columbia River Treaty 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 the B.C. Hydro. The U.S. Entity is the administrator of the 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 computed 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. each appointed Entities to implement Treaty provisions and jointly appointed a Permanent Engineering Board (PEB) to review and report on operations under the Treaty.

II TREATY ORGANIZATION

Entities

There was one meeting of the Columbia River Treaty Entities (including the Canadian and U.S. Entities and the Entity Coordinators) during the year on the morning of 13 March 2002 in Portland, Oregon. The members of the two Entities at the end of the period of this report were:

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

General David A. Fastabend, Member
Division Engineer
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY
Mr. Larry Bell, Chair
Chair & Chief Executive Officer
British Columbia
Hydro and Power Authority
Vancouver, British Columbia

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.
3. Operate a Hydrometeorological system.
4. Assist and cooperate with the PEB in the discharge of its functions.
5. Prepare hydroelectric and flood control operating plans for the use of Canadian storage.
6. Prepare and implement detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under assured operating plans.

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 Entitlement Return 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

Michael B. White
Director, Civil Works & Management
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY COORDINATOR
Kenneth R. Spafford
Principal Engineer,
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

Columbia River Treaty Operating Committee

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

UNITED STATES SECTION
Richard M. Pendergrass, BPA, Co-Chair
William E. Branch, USACE, Co-Chair
Cynthia A. Henriksen, USACE
John M. Hyde, BPA

CANADIAN SECTION
Kelvin Ketchum, B.C. Hydro, Chair
Dr. Thomas K. Siu, B.C. Hydro
Allan Woo, B.C. Hydro
Herbert Louie, B.C. Hydro

Mr. Ketchum replaced Mr. Legge as Chair of the Canadian Section on 1 April 2002.
Mr. Louie was appointed to the Committee on 1 April 2002.

The Operating Committee 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 Operating Committee:

- coordinated the operation of the Treaty storage in accordance with the current hydroelectric and flood control operating plans;
- scheduled delivery of the Canadian Entitlement according to the Treaty and related agreements;
- continued studies for the 2006-07 AOP and Determination of Downstream Power Benefits (DDPB) studies, and began studies for the 2007-08 and 2008-09 AOP/DDPB's;
- completed the 1 August 2002 through 31 July 2003 DOP;
- updated the Libby Operating Plan (LOP) component of the LCA; and
- completed several supplemental operating agreements.

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

In addition to the above tasks, the Committee has developed a proposal for presentation to the Entities and PEB for a streamline method for simplifying the extensive procedures and studies currently used to prepare the AOP/DDPB, and the Committee assisted efforts to develop updated irrigation depletion estimates used to adjust historic streamflows for the AOP/DDPB studies.

Operating Committee at the 17 July 2002 tour of W.A.C. Bennett Dam

Pictured from left to right: John Hyde (BPA Member), William Branch (USACE Co-Chair), Alan Woo (B.C. Hydro Member), Cindy Henriksen (USACE Member), Douglas Robinson (Canadian Entity Secretary), Richard Pendergrass (BPA Chair), Anthony White (U.S. Entity Secretary), Thomas Siu (B.C. Hydro Member), Herbert Louie (B.C. Hydro Member), Kelvin Ketchum (B.C. Hydro Chair) kneeling.

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
Rudd Turner*/Peter Brooks, USACE Co-Chair	Wuben Luo, B.C. Hydro, Member

*Rudd Turner was acting for Peter Brooks for part of the 2002 operating year.

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 Columbia River Treaty (CRT) planning studies and operations to assess hydrometeorological data requirements.

Another key milestone was the Committee's Annual Report, 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 Ronald H. Wilkerson, Member Missoula, Montana	Daniel R. Whelan, Chair Ottawa, Ontario Jack Ebbels, Member Victoria, British Columbia
Earl E. Eiker, Alternate nominee Washington, D.C. George E. Bell, Alternate Portland, Oregon	James Mattison, Alternate Victoria, British Columbia David E. Burpee, Alternate Ottawa, Ontario
Robert A. Bank, Secretary Washington, D.C.	David E. Burpee, Secretary Ottawa, Ontario

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

- assist in reconciling differences that may arise between the Entities;
- make periodic inspections and obtain reports as needed from the Entities to assure that 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; and
- 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, downstream power benefit computations, 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 the morning of 13 March 2002 in Portland, Oregon, 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	CANADIAN SECTION
Robert A. Bank, Chair Washington, D.C.	Roger S. McLaughlin, Chair Victoria, British Columbia
Michael S. Cowan, Member Lakewood, CO	David E. Burpee, Member Ottawa, Ontario
Kamau B. Sadiki, Member Portland, OR	Donna Clarke, Member Ottawa, Ontario
D. James Fodrea, Member Boise, ID	Dr. G. Bala Balachandran, Member Victoria, British Columbia
	Ivan Harvie, Member Calgary, Alberta

Mr. Ivan Harvie was appointed to replace Larry Adamache on 18 February 2002. Mr. Kamau Sadiki, who was an acting member of PEBCOM, was appointed permanently to replace Jim Barton on 24 September 2002. The PEBCOM met with the Operating Committee on 24 October 2001 in Sidney, B.C.

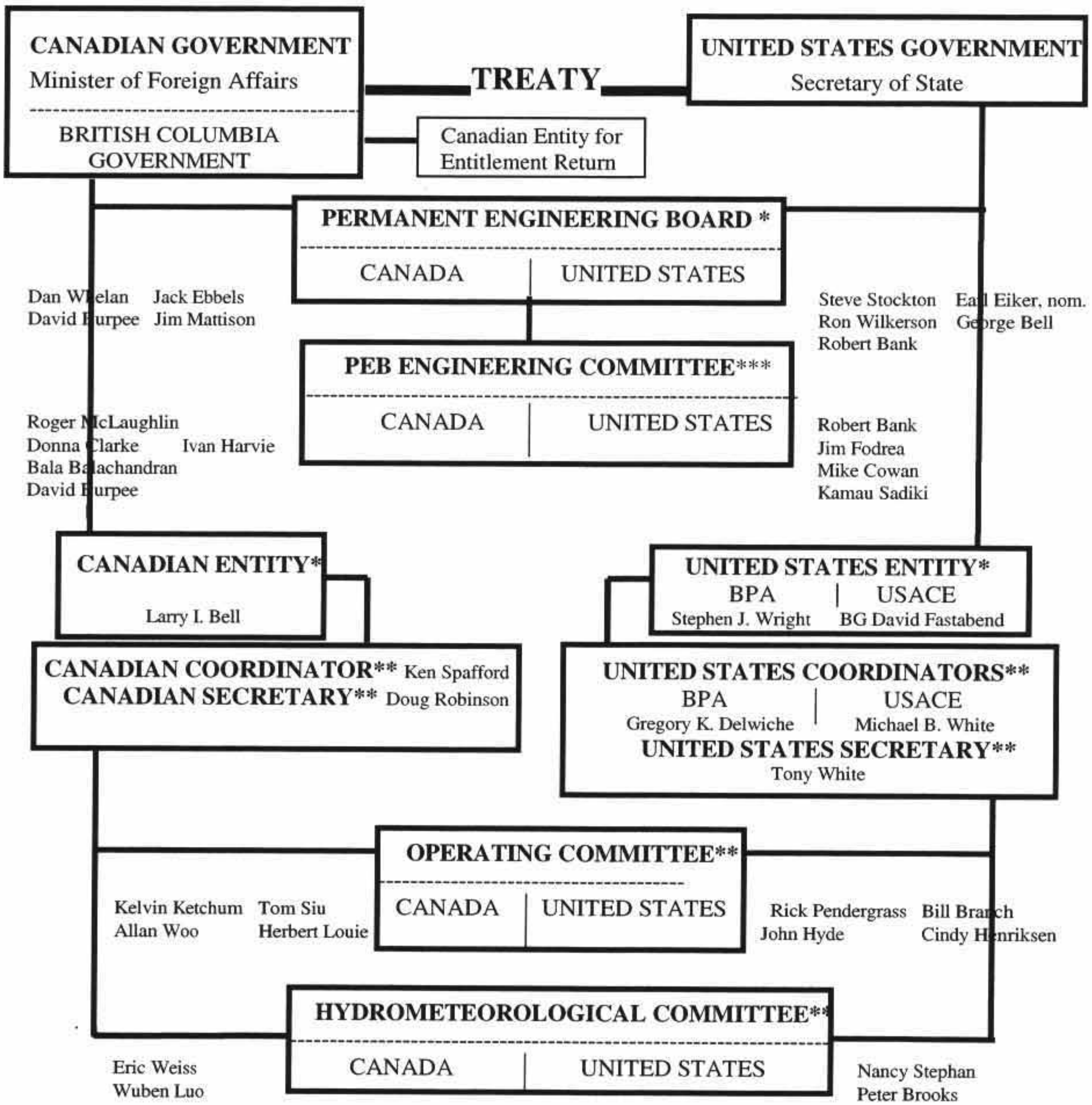
International Joint Commission

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 Columbia River Treaty, 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 United States Section Chair is Dennis L. Schornack of Williamston, MI. The Canadian Section Chair is The Right Honorable Herb Gray of Ottawa, Canada.

Columbia River Treaty Organization



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

III OPERATING ARRANGEMENTS

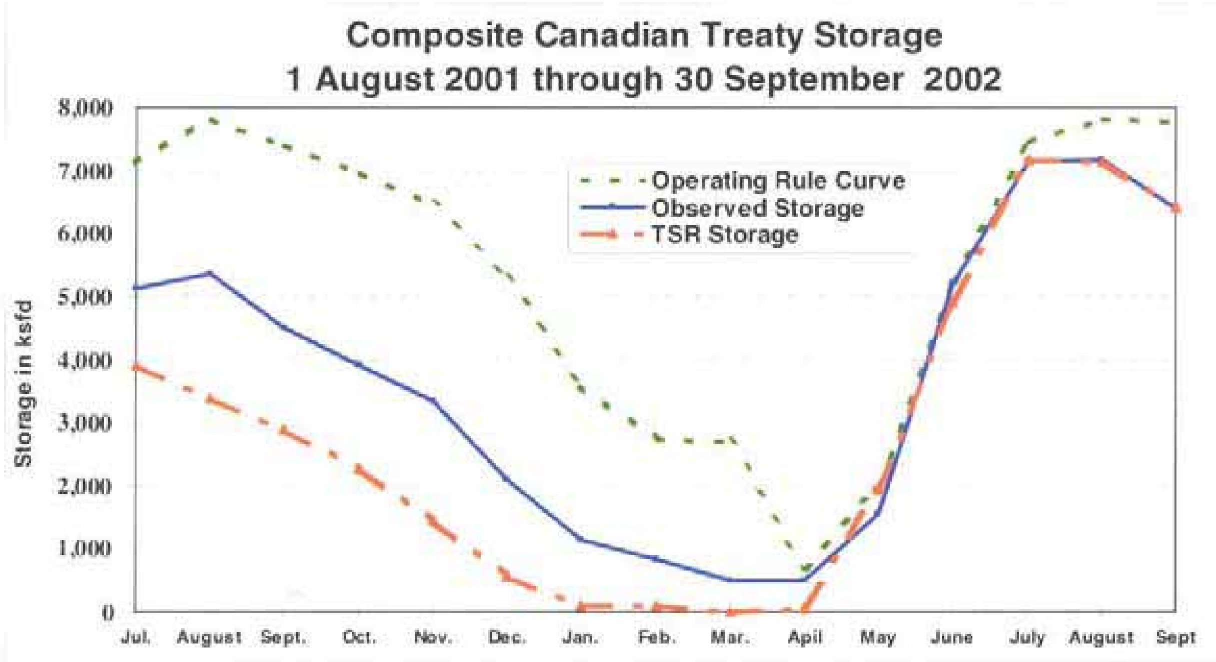
Power and Flood Control Operating Plans

The Columbia River Treaty requires that the reservoirs constructed in Canada be operated pursuant to flood control and hydroelectric operating plans developed thereunder. Annex A of the Treaty stipulates that the United States Entity will submit flood control operating plans (FCOP). Annex A also says 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. Annex A also 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 (POP) together with the "Columbia River Treaty Flood Control Operating Plan" dated October 1999, 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 2001 through 31 July 2002. The operation of Canadian Storage was determined by the 2002 DOP and several supplemental operating agreements. The DOP required a bimonthly 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 2001-02 AOP, with agreed changes. The changes were minor and were mainly updates to flood control rule curves, powerhouse definition data, and the operation of the Brownlee project. Most of the hydrographs and reservoir charts in this report are for a thirteen-month period, July 2001 through July 2002.

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 16 August 2001 through 30 April 2002, and reached empty on 31 March 2002. TSR refill during May through July was limited by minimum flow requirements at Mica.



Assured Operating Plan

The 2001-02 and 2002-03 AOP's, both dated January 2000, established ORC's, Critical Rule Curves (CRC), Mica Operating Criteria, and other operating criteria for Duncan, Arrow, and Mica that were used to develop the DOP that guided the operation of Canadian storage during the period covered by this report. The ORC's were derived from CRC's, Assured Refill Curves, Upper Rule Curves, Variable Refill Curves (VRC's), 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 1999 FCOP, and are used to define an upper limit to the operation of Canadian storage. The AOP was developed with a 5:2 flood control split requiring 5.1 Maf of flood control space at Mica and 2.08 Maf at Arrow. Actual operations for 2002 used a 3:4 flood control split, which provided 3.6 Maf at Mica and 4.08 Maf at Arrow. The CRC's 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 developed a proposal for a streamline method for completing AOP/DDPB studies and are currently working on studies for the 2006-07, 2007-08, and 2008-09 AOP/DDPB's. The Entities recognize that the 2006-07 and 2007-08 AOP/DDPB studies are behind the specified schedule and seek to put the AOP/DDPB process back on schedule during the next reporting period. The proposed methodology is designed to meet all criteria defined in the Treaty, Annexes A & B, and Protocol.

Determination of Downstream Power Benefits

For each operating year, the Determination of Downstream Power Benefits (DDPB) resulting from Canadian Treaty storage is made in conjunction with the AOP according to procedures defined in the Treaty, Annexes A & B, and Protocol. The total Treaty downstream power benefits as a result of the operation of Canadian storage for operating years 2001-02 and 2002-03 were determined to be 1,065.1 MW and 1,068.9 MW average annual usable energy and 2,854.2 MW and 2,341.4 MW dependable capacity, respectively.

In conjunction with the 2006-07, 2007-08, and 2008-09 AOP studies, the Entities initiated studies for the 2006-07, 2007-08, and 2008-09 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 thirty 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 will expire 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 2001 through 31 July 2002, the amount returned based on the operation of Duncan and Arrow was 292.1 aMW of energy, scheduled at rates up to 782.6 MW, and for the period 1 August 2002 through 30 September 2002, the amount returned for Duncan and Arrow was 293.1 aMW of energy, scheduled at rates up to 642.0 MW.

The sale of the Canadian Entitlement to downstream power benefits resulting from the operation of Mica continued during the period covered by this report. 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 95 aMW at rates up to 187 MW from 1 August 2001 through 31 March 2002, and 93 aMW at rates up to 167 MW from 1 April 2002 through 31 July 2002.

For operating year 2001-02 the estimate of 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 United States only. Therefore, the Entities agreed that, in accordance with Sections 7 and 10 of the CEPA, the United States was not entitled to receive any compensating energy or capacity. Similarly, for operating year 2002-03, there was no decrease in the

Energy Entitlement, but there was a 0.3 MW decrease in the Capacity Entitlement. The Entities agreed in the DDPB that, in accordance with Sections 7 and 10 of the CEPA, the United States was entitled to receive 0.3 MW capacity and no energy. However, because the amount was very small, the Entities agreed in the DOP to waive the delivery of this capacity.

Detailed Operating Plan

During the period covered by this report, the Operating Committee used the 1 August 2001 through 31 July 2002 "DOP for Columbia River Treaty Storage," dated July 2001 and the 1 August 2002 through 31 July 2003 DOP, dated July 2002, to guide storage operations. These DOP's established criteria for determining the ORC's, proportional draft points, and other operating data for use in actual operations. The DOP used AOP loads and resources, and AOP rule curves for both Canadian and U.S. projects to develop the TSR study. The TSR study was updated twice monthly throughout the operating year, and together with supplemental operating agreements, defined the end-of-month draft rights for Canadian storage. The VRC's and flood control requirements subsequent to 1 January 2002 were determined on the basis of seasonal volume runoff forecasts during actual operation. The VRC calculations for Canadian reservoirs and Libby for the 2001-02 operating year are shown in Tables 2 through 5. The tabular calculation in Table 5 for Libby was used in the TSR only and was 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 Libby Operating Plan was updated by the USACE in 2002.

Entity Agreements

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

Date Agreement Signed by Entities	Description
28 June 2002	Columbia River Treaty Entity Agreement Relating to Extension of the Expiration Date of the Non-Treaty Storage Agreement.
22 July 2002	Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for 1 August 2002 through 31 July 2003.

Operating Committee Agreements

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

Date Agreement Signed by Committee	Description	Authority
17 October 2001	Addendum to Columbia River Treaty Operating Committee Agreement on Operation of Summer Treaty Storage for 1 August 2001 through 31 March 2002, BPA Contract No. 01PB24335	Detailed Operating Plan, 1 August 2001 through 31 July 2002, approved 13 July 2001 and dated July 2001
7 February 2002	Columbia River Treaty Operating Committee Agreement on Nonpower Uses for 1 January through 31 July 2002	Detailed Operating Plan, 1 August 2001 through 31 July 2002, approved 13 July 2001 and dated July 2001
30 August 2002	Agreement among the Columbia River Treaty Operating Committee and the Bonneville Power Administration and British Columbia Hydro and Power Authority 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

Non-Treaty Storage Agreements

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. By the Entity Agreement dated 28 June 2002, the Entities 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.

Sub-agreements under the Non-Treaty Storage agreement are monitored by the Operating Committee to ensure Treaty storage and releases are not impacted. BPA and B.C. Hydro executed an April-September storage-release verbal/e-mail agreement, a standardized May-June storage/July-August release agreement to benefit fisheries, and a Treaty Special Storage option under the NTSA which modified system operations for recreation, fisheries, and power purposes.

IV WEATHER AND STREAMFLOW

Weather

A cool and wet July 2001 transitioned to a warmer and drier-than-normal August as upper level high pressure strengthened early in August and reached its regional peak about the middle of the month. Slightly below normal regional temperatures in July were followed by positive departures up to +3.3 °C (+6.0 °F) in August. Although a couple of record high temperatures occurred in early July, many more occurred in August. Most of these were in Montana, both at the beginning and end of August. An approaching front, pushing up against the upper high, brought over 2.5 cm (1 inch) of rain to Astoria, Oregon and from 3.6 to almost 5.1 cm (1.4 to almost 2 inches) around Seattle, Washington late in August. July precipitation averaged 102 percent of normal at the Columbia River above Grand Coulee, 118 percent of normal at the Snake River above Ice Harbor, and 103 percent of normal at the Columbia River above The Dalles. August precipitation totaled 32 percent of normal at the Columbia River above Grand Coulee, 20 percent of normal at the Snake River above Ice Harbor, and 32 percent of normal at the Columbia River above Grand Coulee.

The fall of 2001 opened dry and mild, transitioned to a cool and wet mid-season, and closed wet with near to slightly below normal temperatures. This was especially true west of the Cascades, while eastern sections gained more precipitation late in the period. Apart from a couple of weak fronts in September and early October, high pressure aloft held. It closely followed climatology, sufficiently weakening to allow the jet stream to bring storms in mid to late October, and again later in November. But, the high pressure ridge temporarily recovered in early November. This placed eastern sections in a drier mode, even though the storms returned precipitation late in the month. Frequent storms continued into the first part of December. Temperatures were above normal for the month of September and several record high temperatures were reached, mostly in western Montana. September 2001 was the hottest September on record in Helena, Montana. The average monthly departure was +5.1 °C (+9.2 °F). Near normal temperatures in October gave way to above normal temperatures in November. High temperature records again outnumbered low temperature records in October and November 2001, most occurring early in each month. The majority of the new high temperature records were again set in western Montana. Precipitation in September averaged 48 percent of normal at the Columbia River above Grand Coulee, 54 percent of normal at the Snake River above Ice Harbor, and 49 percent above normal at the Columbia River above The Dalles. For October, 128 percent of normal precipitation fell at the Columbia River above Grand Coulee, 132 percent of normal at the Snake River above Ice Harbor, and 145 percent of normal at the Columbia River above The Dalles. In November, 67 percent of normal precipitation fell at the Columbia River above Grand Coulee, 96 percent of normal at the Snake River above Ice Harbor, and 86 percent of normal at the Columbia River above The Dalles.

December 2001 through February 2002 was a wet mild period, concentrated mainly across the northern U.S. basins and through Canada. While the jet stream targeted these areas, high pressure aloft kept southern basins drier than normal, by weakening incoming fronts. December's regional temperatures averaged near normal, January's above normal, and February's were slightly below normal. There were several high temperature records established for the three-month period, most occurring in February, ironically when regional temperatures averaged cooler than normal. December precipitation was 90 percent of normal at the Columbia River above Grand Coulee, 111 percent of normal at the Snake River above Ice Harbor, and 98 percent of normal at the Columbia River above The Dalles. In January, these values were 101 percent of normal at the Columbia River above Grand Coulee, 91 percent of normal at the Snake River above Ice Harbor, and 94 percent of normal at the Columbia River above The Dalles. For February, precipitation totaled 114 percent of normal at the Columbia River above Grand Coulee, 49 percent of normal at the Snake River above Ice Harbor, and 82 percent of normal at the Columbia River above The Dalles.

For March through May, a wet period ruled mainly through Canada and across the northwestern U.S. A secondary wet area was over the southeastern basins, mainly in April. An upper level low pressure trough kept a cool northwest flow into the region, the strongest impact of which was felt in March and again in May. Higher pressure aloft ridged up early in April, but did not last through the month. After being suppressed south in early May, it bulged back north about mid month. This caused the storm track to mainly cut across southern B.C. and northwest Montana in mid to late May.

Regional temperatures were below normal in March, with record low temperatures dropping below -17.8 °C (zero °F) in southeast Idaho and western Montana. They included: -1.1 °C (-2.0 °F) in Pocatello, Idaho and –11.6 °C (-21.0 °F) at Havre, Montana. March also had some record high temperatures, coming early in the month before the northwest flow began: Portland, Oregon at 20.6 °C (69.0 °F) and 22.2 °C (72.0 °F) at Salem, Oregon. April temperatures were closer to normal, region wide, although many record temperatures were broken. Some of the new record lows included: Pendleton, Oregon, -3.3 °C (26.0 °F) on 3 April; -5.0 °C (23.0 °F) at Grand Coulee Dam and Yakima, Washington on 24 April, and –6.1 °C (21.0 °F) at Spokane, Washington also on 24 April. In May, temperatures averaged slightly below normal, even though new high temperature records again strongly outnumbered new temperature low records. In March, precipitation was 115 percent of normal at the Columbia River above Grand Coulee, 95 percent of normal at the Snake River above Ice Harbor, and 108 percent of normal at the Columbia River above The Dalles. For April, precipitation was 93 percent of normal at the Columbia River above Grand Coulee, 100 percent of normal at the

Snake River above Ice Harbor, and 95 percent of normal at the Columbia River above The Dalles. Finally, for May, precipitation was 129 percent of normal at the Columbia River above Grand Coulee, 55 percent of normal at the Snake River above Ice Harbor, and 94 percent of normal at the Columbia River above The Dalles.

Drier weather became more widespread across most southern basins, including Oregon and central through southern Idaho. This anomaly expanded north as July progressed. The storm track, therefore, pointed across British Columbia, Washington, northern Idaho and northwest Montana in June then lifted into the Canadian Upper Columbia region in July. Both months were warmer than normal, even though a few low temperature records were tied or broken. Just as in March through May, the new record high temperatures outnumbered the cool ones. For June, these high temperature records included: 27.8 °C (82 °F) at Astoria, Oregon, 30 °C (86 °F) at Olympia, Washington, 31.7 °C (89 °F) at Eugene, Oregon, and 33.9 °C (93 °F) at Portland, Oregon, all on 12 June. On 13 June, another record fell at Portland, Oregon: 36.1 °C (97 °F) and the temperature reached 34.4 °C (94 °F) at Sea/Tac Airport in Seattle, Washington. For July, record high temperatures crumbled at Astoria, Oregon; Olympia, Washington; Portland, Oregon; Boise, Idaho; Pendleton, Oregon; and Missoula, Montana to name a few. Many of these values broke the 100 °F mark, ranging from 38.3 °C (101 °F) at Pocatello, Idaho to 43.3 °C (101 °F) at Boise, Idaho.

June precipitation was 97 percent of normal at the Columbia River above Grand Coulee, 80 percent of normal at the Snake River above Ice Harbor, and 89 percent of normal at the Columbia River above The Dalles. In July, precipitation was 70 percent of normal at the Columbia River above Grand Coulee, 65 percent of normal at the Snake River above Ice Harbor, and 71 percent of normal at the Columbia River above The Dalles.

Chart 1 shows the seasonal precipitation for the Columbia Basin for the 2001 – 2002 water year. Generally the annual precipitation was average to slightly above average on the east and west portions of the basin and below normal in the central and southern tiers of the basin. Snowpack for the basin is summarized in Chart 2. Snow accumulation for the Columbia River above The Dalles was slightly above normal for 2002, in contrast to the drought conditions of 2001. Chart 3 shows the accumulated precipitation for the 2002 water year for the Columbia Basin above Grand Coulee, the Snake River above Ice Harbor, and the Columbia Basin above The Dalles.

Streamflow

Monthly and Seasonal reservoir inflow at many key locations throughout the Columbia Basin are shown in Chart 4. The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 July 2001 through 31 July 2002 are shown on Charts 5 through 7. Chart 8 shows Libby hydrographs. Observed flow with the computed unregulated flow hydrographs for the same 13-month period for Kootenay Lake, Columbia River at Birchbank, Grand Coulee and The Dalles are shown on Charts 9, 10, 11, and 12, respectively. Chart 13 is a hydrograph of observed and unregulated flows at The Dalles during the April through July 2002 period, including a plot of flows occurring if regulated only by the four Treaty reservoirs.

Composite operating year unregulated streamflows in the basin above The Dalles were slightly below average, but well above last year's drought-like streamflows. June was the highest month during the spring runoff, at 120 percent of average. The August 2001 through July 2002 runoff for The Dalles was 154.2 km^3 (125.03 Maf), 90 percent of the 1971-2000 average. The peak unregulated discharge for the Columbia River at The Dalles was 17,180 m^3/s (606,800 cfs) on 7 June 2002. The 2001-02 average monthly unregulated streamflows and their percentage of the 1971-2000 average monthly flows are shown in the following tables (metric and English) for the Columbia River at Grand Coulee and The Dalles. These flows have been adjusted to exclude the effects of regulation provided by storage reservoirs.

Columbia River Flow in Metric Units

Time Period	Columbia River at Grand Coulee in m^3/s Natural Flow	Percentage of Average	Columbia River at The Dalles in m^3/s Natural Flow	Percentage of Average
Aug 01	2,112.9	71	2,565.9	66
Sep 01	1,144.7	63	1,646.9	61
Oct 01	805.4	63	1,575.0	67
Nov 01	1,202.8	87	2,193.4	82
Dec 01	940.8	77	1,935.8	69
Jan 02	1,245.9	105	2,472.4	85
Feb 02	1,139.4	85	2,373.5	69
Mar 02	1,206.7	68	2,849.4	65
Apr 02	3,504.1	101	6,495.1	96
May 02	6,961.2	92	10,631.7	87
Jun 02	11,522.6	132	15,927.0	120
Jul 02	6,322.9	116	7,955.8	109
Operating Period	3,059.2	92	4,890.3	90

Columbia River Flow in English Units

Time Period	Columbia River at Grand Coulee in cfs		Columbia River at The Dalles in cfs	
	Natural Flow	Percentage of Average	Natural Flow	Percentage of Average
Aug 01	74,660	71	90,668	66
Sep 01	40,448	63	58,195	61
Oct 01	28,459	63	55,654	67
Nov 01	42,500	87	77,504	82
Dec 01	33,244	77	68,404	69
Jan 02	44,023	105	87,365	85
Feb 02	40,262	85	83,871	69
Mar 02	42,641	68	100,685	65
Apr 02	123,821	101	229,508	96
May 02	245,979	92	375,679	87
Jun 02	407,159	132	562,793	120
Jul 02	223,423	116	281,124	109
Operating Period	108,035	92	172,700	90

Seasonal Runoff Forecasts and Volumes

Observed 2002 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	8.75	7,097	114
Duncan Reservoir Inflow	2.83	2,291	112
Mica Reservoir Inflow	14.28	11,576	102
Arrow Reservoir Inflow	28.60	23,183	101
Columbia River at Birchbank	53.79	43,603	108
Grand Coulee Reservoir Inflow	80.58	65,320	108
Snake River at Lower Granite	24.65	19,986	87
Columbia River at The Dalles	115.71	93,804	101

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2002 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 2002 forecast of January through July runoff for the Columbia River above The Dalles was 118.9 km^3 (96.4 Maf) and the actual observed runoff was 128.0 km^3 (103.8 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

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

V RESERVOIR OPERATION

General

The 2001-2002 operating year followed the second lowest January through July runoff at The Dalles since 1928. Reservoirs were low and the region was anticipating what the new year would bring. Precipitation across the basin began to return to normal by the fall of 2001. The official January WSF prepared by the National Weather Service was 93 percent of average (123.3 km^3 (100.0 Maf) for the January through July period measured at The Dalles) for the period 1971-2000. The April 2002 WSF for The Dalles was 90 percent of average (118.9 km^3 (96.4 Maf) for the January through July period).

Project releases were being used to maintain a minimum flow at Bonneville Dam from November through April for listed chum downstream of Bonneville Dam. Projects were drafted January through April for flood control. Flood control drafts in January through April helped to maintain a flow of 3,539.6 m^3/s (125,000 cfs) at Bonneville Dam to keep the chum spawning area downstream of Bonneville Dam wet. Once the chum move into the area and spawn during November and December, this flow should be maintained through early May when the fish emerge.

Since the WSF had returned to near average, normal operations under the NMFS 2000 BiOp resumed. Spill was executed for spring and summer 2002 at all projects, except Lower Monumental Dam, and the Lower Snake projects were operated at, or near, their minimum operating pools for the season. Storage projects were again required to reach their 10 April refill target and the system was operated to meet flow objectives at McNary and Lower Granite Dams, if possible.

Flows in the Basin were generally below average until April and the peak of the runoff for 2002 occurred in June. The observed January through July unregulated runoff at The Dalles was 97 percent of average (128.0 km^3 (103.8 Maf)). All U.S. storage projects filled to within 0.15 m (0.5 feet) from full in 2002.

Canadian Treaty Storage Operation

Due to the low water supply experienced throughout the Columbia River system during 2001, Canadian Treaty storage (Canadian storage) did not refill, reaching 13.6 km^3 (11.0 Maf) or 71 percent full on 19 August 2001. Canadian storage drafted to 1.2 km^3 (0.9 Maf) on 31 March 2002 and refilled to 17.5 km^3 (14.2 Maf) or 91 percent full on 31 July 2002. During 2002, the refill of Canadian storage was limited by minimum flow requirements at Mica.

As specified in the DOP, the release of Canadian Treaty storage is made effective at the Canadian-United States 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-United States border. The terms under/overrun are used in the description of Mica Reservoir operations below.

Mica Reservoir

As shown in Chart 5, the Mica (Kinbasket) Reservoir level was at elevation 738.80 m (2,423.8 feet) on 31 July 2001. The reservoir reached its maximum elevation for the year of 742.14 m (2,434.8 feet) on 3 September 2001, 13.24 m (40.2 feet) below full pool elevation of 754.38 m (2,475 feet). This level was the second lowest annual peak on record. The only year with a lower peak was 1993 at 737.46 m (2,419.4 feet).

Inflow into Mica reservoir was 83 percent of normal over the period August 2001 to December 2001. Over this same period, Mica outflow varied from a monthly average low of 450 m^3/s (15,900 cfs) in November to a monthly average high of 830 m^3/s (29,300 cfs) in December. The reservoir drafted to 720.63 m (2,397.0 feet) by 31 December, matching the historical minimum elevation for that date. The Mica project had an underrun of 2,488 hm^3 (1,017 ksfd) on 31 July 2001. The underrun continued to increase through November, reaching a record 4,233 hm^3 (1,730 ksfd) by 30 November 2001. The B.C. Hydro NTSA was at 688 hm^3 (281 ksfd) on 31 July 2001 and 944 hm^3 (386 ksfd) on 31 December 2001. The corresponding U.S. NTSA was at 724 hm^3 (296 ksfd) and 1,128 hm^3 (461 ksfd), respectively.

Inflow into Mica reservoir was 101 percent of normal over the period January 2002 to August 2002. Outflow over this same period varied from a monthly average high of 801 m^3/s (28,300 cfs) in January to a monthly average low of 20 m^3/s (700 cfs) in June. The reservoir drafted to its lowest elevation of the year at 712.40 m (2,337.2 feet) on 12 April 2002, 0.95 m (3.2 feet) below the previous historical low pool elevation of 713.35 m (2,340.4 feet) on 23 April 1993. Due to below normal spring temperatures, similar to the preceding year, the freshet was delayed by about one month and inflow did not start appreciably until late May. The reservoir reached the maximum elevation for the year of 751.36 m (2,465.1 feet) on 3 September 2002, 3.02 m (9.9 feet) below the full pool elevation of 754.38 m (2,475 feet).

The Mica actual discharges were significantly greater than the sum of Mica DOP and NTSA releases from December 2001 through June 2002 due to the flex operation between Mica and Arrow. As a result, the record underrun of 4,233 hm^3 (1,730 ksfd) recorded on 30 November 2001 was reduced to 110 hm^3 (45 ksfd) by 30 June 2002. The B.C. Hydro and U.S. NTSA on 31 August 2002 was at 1,512 hm^3 and 1,720 hm^3 (618 ksfd and 703 ksfd), respectively.

Revelstoke Reservoir

During the 2001-02 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 reached its maximum elevation for the year of 430.42 m (1,412.1 feet) on 3 August 2001. This level was the third lowest annual peak on record, with 1973 and 1977 having lower peak levels of 429.04 m (1,407.6 feet) and 430.02 m (1,410.8 feet), respectively. The reservoir drafted through to January 2002, reaching the minimum elevation of 422.52 m (1,386.2 feet) on 14 January 2002.

Arrow discharge was reduced from 424.8 m^3/s to 141.6 m^3/s (15,000 cfs to 5,000 cfs) on 18 July 2001 for approximately nine hours to facilitate repairs to the upstream debris boom. Discharges were then gradually increased to a daily peak flow of 1,806.6 m^3/s (63,800 cfs) on 29 August 2001. Discharges decreased over the autumn months from an average of 1,387.7 m^3/s (49,700 cfs) in September to 846.8 m^3/s (29,900 cfs) in October and 934.6 m^3/s (33,000 cfs) in November. The discharge increased to an average of 1,209.3 m^3/s (42,700 cfs) in December.

The Arrow fisheries operations were conducted under the terms of two Operating Committee agreements, "Agreement on Operation of Summer Treaty Storage For 1 August 2001 through 31 March 2002" and "Operation of Treaty Storage for Nonpower Uses for 1 January through 31 July 2002." These agreements enabled the Arrow project flows to be adjusted to enhance whitefish and rainbow trout spawning and emergence downstream of the Arrow project in B.C.

From 21 December 2001 to 20 January 2002, Arrow outflow was held near 934.6 m^3/s (33,000 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. Arrow outflow through the emergence period from 22 January to 26 March was held between 679.7 m^3/s and 736.3 m^3/s (24,000 cfs and 26,000 cfs) to help protect deposited eggs. On 28 March, the outflow from Arrow was reduced to 424.8 m^3/s (15,000 cfs) to meet objectives for rainbow trout spawning under the Non-Power Uses Agreement. During May, Arrow outflow increased to 566.4 m^3/s (20,000 cfs), under the same agreement, to help meet non-power flow requirements in the U.S.

The Arrow reservoir drafted to a minimum elevation for the 2001-02 year of 422.52 m (1,386.2 feet) on 14 January 2002 and reached a maximum elevation of 439.92 m (1,443.31 feet) on 17 July 2002, 0.21 m (0.7 feet) below the full pool elevation of 440.13 m (1,444.0 feet).

The Arrow Lakes Generating Station began commercial operation during 2002, after the successful completion of commissioning tests. The first generating unit began commercial operation on 9 February 2002 and the second unit on 17 May 2002.

Duncan Reservoir

As shown in Chart 7, the Duncan reservoir did not refill during 2001, reaching a maximum elevation of 571.72 m (1,875.7 feet), 4.97 m (16.3 feet) below full pool on 4 August 2001. For the period of August through December, Duncan discharge varied between 5.7 m^3/s and 283.2 m^3/s (200 cfs and 10,000 cfs) to support Kootenay Lake elevations. On 31 December, the reservoir reached elevation 550.93 m (1,807.5 feet), 4.06 m (13.3 feet) above empty. In January 2002, the project discharge averaged 63.0 m^3/s (2,230 cfs). From February through April 2002, Duncan discharge was slightly greater than the average monthly inflows, which gradually drafted the project to near empty by mid-March 2002. On 14 May, discharge was reduced to the project minimum release of 3 m^3/s (100 cfs) to begin refill.

Early season water supply forecasts for Duncan were 94 percent of average for the period of February through September 2002 but these estimates increased gradually to 111 percent by August 2002 due to above average precipitation. Discharge from the project increased from 3 m^3/s (100 cfs) on 10 July 2002 to 283 m^3/s (10,000 cfs) on 15 July 2002. The reservoir reached full pool of 576.68 m (1,892.0 feet) on 15 July, temporarily reaching as high as elevation of 576.78 m (1,892.3 feet) on 16 July 2002. Due to continued high inflows, project discharge was increased to 411 m^3/s (14,500 cfs) from 17 July to 20 July to control the reservoir elevation. This period of high project discharge combined with high natural flows on the Ladeau River resulted in flood impacts and the temporary closure of a downstream sawmill. Project discharge was reduced to 133 m^3/s (4,700 cfs) by 31 July as inflows receded.

In August, Duncan discharge was increased up to 227 m^3/s (8,000 cfs) as part of a Libby/Canadian storage exchange agreement. The reservoir drafted to elevation 574.57 m (1,885.0 feet) by the end of August. During September project discharge was maintained at, or below, 227 m^3/s (8,000 cfs) to facilitate kokanee spawning.

Libby Reservoir

As shown in Chart 8, Lake Koocanusa began July 2001 at elevation 741.06 m (2,431.3 feet), 8.44 m (27.7 feet) below full. Outflows were maintained at 169.90 m^3/s (6,000 cfs) for most of the period of July through 27 November 2001. A small deviation from BiOp ramping rates occurred in July due to increases in discharges to aid in the recovery of a drowning victim and to dislodge algae from rocks below Libby Dam. Outflow was ramped up to 266.18 m^3/s (9,400 cfs) on 28 November to draft to the end of December flood control elevation of 734.87 m (2,411.0 feet). The flow fit in with a request from the Idaho Office of Species Conservation who desired a flow of 283.17 m^3/s (10,000 cfs) from 1 December to 23 December to study burbot migration. Outflows in December were maintained at 266.18 m^3/s (9,400 cfs) until 23 December. Flows were ramped down to 226.53 m^3/s (8,000 cfs) over the Christmas and New Years holidays. Lake Koocanusa was at elevation 734.72 m (2,410.5 feet) on 31 December.

January outflows were 283.17 m^3/s (10,000 cfs) until 10 January and were then increased to 410.59 m^3/s (14,500 cfs) after the January final WSF was issued. USFWS had requested outflows between 169.90 m^3/s and 283.17 m^3/s (6,000 cfs and 10,000 cfs) for burbot from January through the first week of February. Because flows in that range would not draft the project to the end of January target, USFWS agreed at the 9 January 2002 Technical Management Team meeting that a flat discharge for the remainder of the month would be the preferred alternative given the USACE flood control requirements. The USACE increased discharge to 410.59 m^3/s (14,500 cfs) and maintained that flow through January.

The National Weather Service released the February early bird WSF on 31 January, which showed a dramatic increase for Libby. With a forecast of 102 percent of average (7.85 km^3 (6,360 kaf)), Libby would have problems drafting to the end of month flood control elevation even at full powerhouse capacity. Flows were increased from 410.59 m^3/s to 679.60 m^3/s (14,500 cfs to 24,000 cfs) by 6 February in anticipation of a higher WSF. The February final WSF came in at 96 percent of average and as a result, the full powerhouse discharges were not needed for flood control. Discharges were reduced to

226.53 m^3/s (8,000 cfs) and Libby ended the month of February at 724.14 m (2,375.8 feet), within 0.06 m (0.2 feet) of the 28 February flood control point.

Libby outflows were ramped down to 113.27 m^3/s (4,000 cfs) by 12 March and remained there until 15 May. For 2002, USFWS requested a sturgeon pulse that focused on the larvae stage of development. The request was to release 226.53 m^3/s (8,000 cfs) for bull trout from 15 May until the start of the USACE spill test in the third week of June, then maintain flows at Bonners Ferry, Idaho at 566.34 m^3/s (20,000 cfs) for two weeks. Due to an increase in the April WSF, the USACE Reservoir Control Center requested a deviation from the 15 April flood control target and targeted the 30 April flood control refill curve. Precipitation in the Kootenai Division in May was high at 9.04 cm (3.56 inches), 160 percent of average for the month.

2002 Spill at Libby Dam

With the high precipitation in May, the June early bird WSF showed a significant increase at Libby for the April through August period (increased from 100 percent to 114 percent). As a result, Libby flows were ramped up to full load, 736.24 m^3/s (26,000 cfs), by 12 June. Temperatures increased in June and inflows rose dramatically. Seattle District was planning on conducting a spill test at Libby per the 2000 USFWS and NMFS BiOps. The spill test was a significant change in operation since the project had not spilled since June 1986 and had not spilled significantly (amounts over 141.6 m^3/s (5,000 cfs)) since July 1981. Spill for the three day test began on 25 June. The reservoir began filling quickly and it became apparent that Libby would need to spill more water than the test required to avoid filling the project too quickly. After the completion of the test, spill amounts were increased and the project reached a maximum outflow of 1,132.67 m^3/s (40,000 cfs) on

2 July 2002. Libby ended the month of June at 748.83 m (2,456.8 feet), 0.67 m (2.2 feet) from full. Libby inflow in June was 1,517.78 m^3/s (53,600 cfs), 146 percent of average. Inflows for the water year peaked at 2,035.98 m^3/s (71,900 cfs) on 18 June.

Lake Koocanusa reached its peak elevation, 749.38 m (2,458.6 feet) on 15 July, 0.12 m (0.4 feet) from full. Inflows began receding and Libby stopped spill for the year on 17 July. Flows for the remainder of July were held steady to benefit habitat and food supply for downstream fish, and to draft to 743.41 m (2,439.0 feet) by 31 August. On 8 August the U.S. and Canadian Entities agreed to a Libby/Duncan swap of no more than 171.26 hm^3 (70 ksfd). Outflows at Libby were adjusted weekly to reflect the new end of month target of 744.41 m (2,442.3 feet). Libby ended the month of August at 744.30 m (2441.93 feet), 0.89 m (2.9 feet) above the BiOp interim draft limit of 743.41 m (2439.0 feet). The actual amount of water that Libby swapped was 154.13 hm^3 (63 ksfd). Libby outflows for August averaged 489.88 m^3/s (17,300 cfs). Actual runoff for the April through August period at Libby was 8.75 km^3 (7,097 kaf), 114 percent of average. Libby outflows were ramped down after the August draft and reached 169.9 m^3/s (6,000 cfs) by 4 September and remained there for the entire month of September.

Kootenay Lake

As shown in Chart 9, the level of Kootenay Lake at Queens Bay was at elevation 531.28 m (1,743.0 feet) on 31 July 2001. Kootenay Lake was drafted to elevation 531.21 m (1,742.8 feet) on 19 August and then gradually filled to 531.34 m (1,743.2 feet) by the end of the month as the result of increased Duncan discharge. Kootenay Lake discharge averaged 475.4 m^3/s (16,790 cfs) in August.

During the period September through December 2001, the lake filled in September due to increased Duncan discharge but drafted thereafter in the remaining months to the end of December elevation of 531.11 m (1,742.5 feet). The lake levels remained well below the IJC levels throughout the fall due to low inflows.

For the month of January, Kootenay Lake filled due to an increase in Libby discharge starting 10 January 2002. The reservoir rose to elevation 531.39 m (1,743.4 feet) by 31 January and Kootenay Lake discharge averaged 564.1 m^3/s (19,920 cfs) for the month.

Kootenay Lake was drafted during February and March to stay below the IJC 1 April limit of 530.14 m (1,739.32 feet). Kootenay Lake discharge was adjusted to control the reservoir below the IJC limit while meeting system requirements. On 31 March 2002, Kootenay Lake was at its minimum elevation of 529.76 m (1,738.0 feet).

In April, the total inflow into the lake was greater than lake discharge and the lake elevation rose to 530.6 m (1,740.8 feet) by the end of the month. Kootenay Lake discharge remained near inflow until 14 April 2002 when the Kootenay Lake Board of Control declared the commencement of spring rise on the Kootenay. Following the declaration of spring freshet, Kootenay Lake was operated in accordance to the IJC lowering formula.

In late May, the Kootenay Lake level rose sharply in response to the spring freshet inflow. Inflow peaked at 2601.4 m^3/s (91,864 cfs) on 22 May 2002. Kootenay Lake discharge was increased in accordance with the IJC Order for Kootenay Lake. Discharge from the lake peaked at 2,259.5 m^3/s (79,790 cfs) on 30 June 2002. Kootenay Lake reached its maximum elevation for the year of 533.78 m (1,751.2 feet) on 30 June 2002, about a month later than the previous year.

Beginning in July, Kootenay Lake levels started to drop due to receding runoff. The reservoir discharge was kept higher than the total inflow into the lake to control reservoir levels slightly below the IJC limits. During the summer of 2002, the level at the Nelson gage did not draft below the trigger elevation of 531.36 m (1,743.32 feet). The lake drafted to 531.72 m^3/s (1,744.5 feet) by the end of August.

Storage Transfer Agreements

The CRTOC initiated a U.S. – Canada Treaty 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 Biological Opinion 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.

By 31 August 2002 as a result of implementing the Libby-Treaty storage transfer, Libby was 63 ksfd above its draft limit at elevation 2441.93 feet, and the Canadian Treaty storage target was adjusted to be 63 ksfd below indicated TSR levels. As August progressed, the hydrologic conditions in the Columbia basin deteriorated which increased the target Treaty draft. Between the initial (8 August 2002) TSR study, and the final TSR study, the desired end-of-month Treaty storage draft increased by 179 ksfd. While Arrow Treaty discharges were increased in late August in response to this deeper target draft, the increase was limited to avoid large discharge fluctuations, and an inadvertent Treaty storage of 94 ksfd (relative to the adjusted TSR target) resulted by 31 August 2002.

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 Columbia River Treaty and operating plans and agreements described in Section III. Consistent with all DOP's prepared since the installation of generation at Mica, the 2001-02 and 2002-03 DOP's were designed to achieve optimum power generation at-site in Canada and downstream in Canada and the U.S., in accordance with paragraph 7 of Annex A of the Treaty.

During the period covered by this report, Libby reservoir was operated for flood control and other purposes in accordance with the Treaty and the 1999 Columbia River Treaty Flood Control Operating Plan. During a portion of the year, Libby operated for power purposes according to the PNCA AER. During December through early February 2002 the USACE coordinated operations for burbot in the Kootenai River, which are proposed for listing under the Endangered Species Act. During the remainder of the operating year, Libby operated for storage and releases recommended for endangered white sturgeon and salmon by the 2000 USFWS and NMFS Biological Opinions.

Flood Control

With the 2002 water supply forecasts averaging near normal across the Columbia River Basin, the reservoir system, including the Columbia River Treaty projects were required to draft for flood control in preparation for the spring freshet. Inflow forecasts and reservoir regulation modeling were done weekly throughout the winter and spring. Projects were operated according to the 1999 Flood Control Operating Plan. With above normal precipitation in May and warm temperatures in June, actual runoff volumes were higher than forecasted at the Columbia River Treaty projects. Libby Dam had to spill for the first time in 21 years because the reservoir was filling quickly. The unregulated peak flow at The Dalles, Oregon, shown on chart 13, is estimated at 17,180 m^3/s (606,800 cfs) on 7 June and a regulated peak flow of 10,600 m^3/s (374,400 cfs) occurred on 6 June. The unregulated peak stage at Vancouver, Washington was calculated to be 6.34 m (20.8 feet) on 8 June and the highest-observed stage was 3.99 m (13.1 feet) on 18 April.

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 Columbia River Treaty Flood Control Operating Plan. Low runoff conditions last year and slightly below normal runoff conditions this year caused Mica to be drafted very deeply for power. There were no daily operations specified for

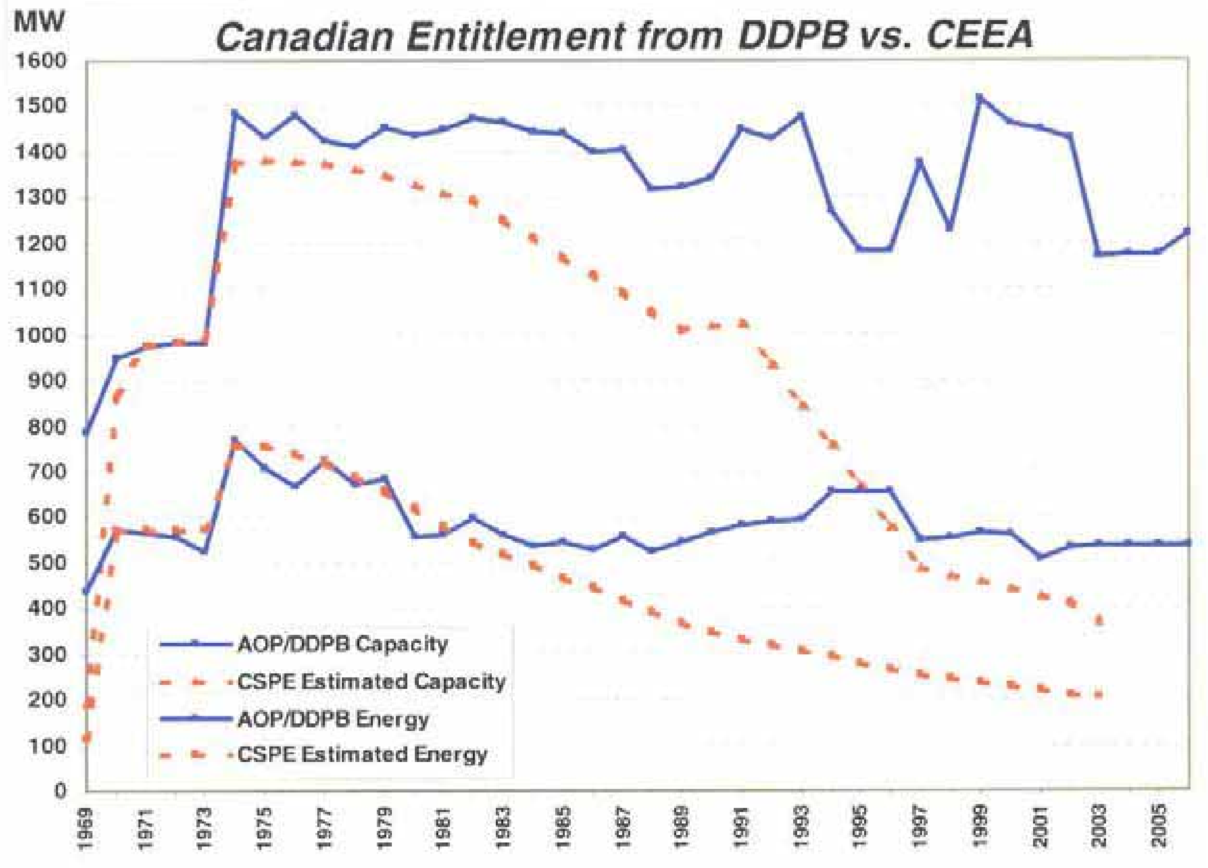
Arrow, and the projects were able to meet both fish flow and flood control objectives. In operating year 2002-2003 Mica and Arrow operated to "shifted" flood control as defined in the 1999 FCOP. On 25 June 2002 B.C. Hydro requested to operate Mica and Arrow to the flood control storage allocations of 3.6 Maf maximum draft at Arrow and 4.08 Maf maximum draft at Mica. The U.S. Section of the CROTC 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 ICF's at The Dalles were 9,340 m^3/s (330,000 cfs) on 1 January 2000; 9,490 m^3/s (335,000 cfs) on 1 February; 9,260 m^3/s (327,000 cfs) on 1 March; 9,230 m^3/s (326,000 cfs) on 1 April; and 9,230 m^3/s (326,000 cfs) on 1 May. As mentioned earlier, the observed peak flow at The Dalles was 10,600 m^3/s (374,400 cfs) on 6 June 2002. Data for the 1 May ICF computation are given in Table 6.

Canadian Entitlement

From 1 August 2001 through 31 July 2002, 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 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 2001 through 31 July 2002, as was allowed by the 29 March 1999 Agreements on "Aspects of the Delivery of the Canadian Entitlement for 4/1/98 Through 9/15/2024" and "Disposals of the Canadian Entitlement Within the U.S. for 4/1/98 Through 9/15/2024."

During the period covered by this report, the Canadian Entitlement to downstream power benefits resulting from the operation of Mica was sold to the CSPE. In accordance with the CEEA dated 13 August 1964, 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), and 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. The following graph compares the historic Canadian Entitlement computation from the DDPB studies to the amount sold under the CEEA contract.



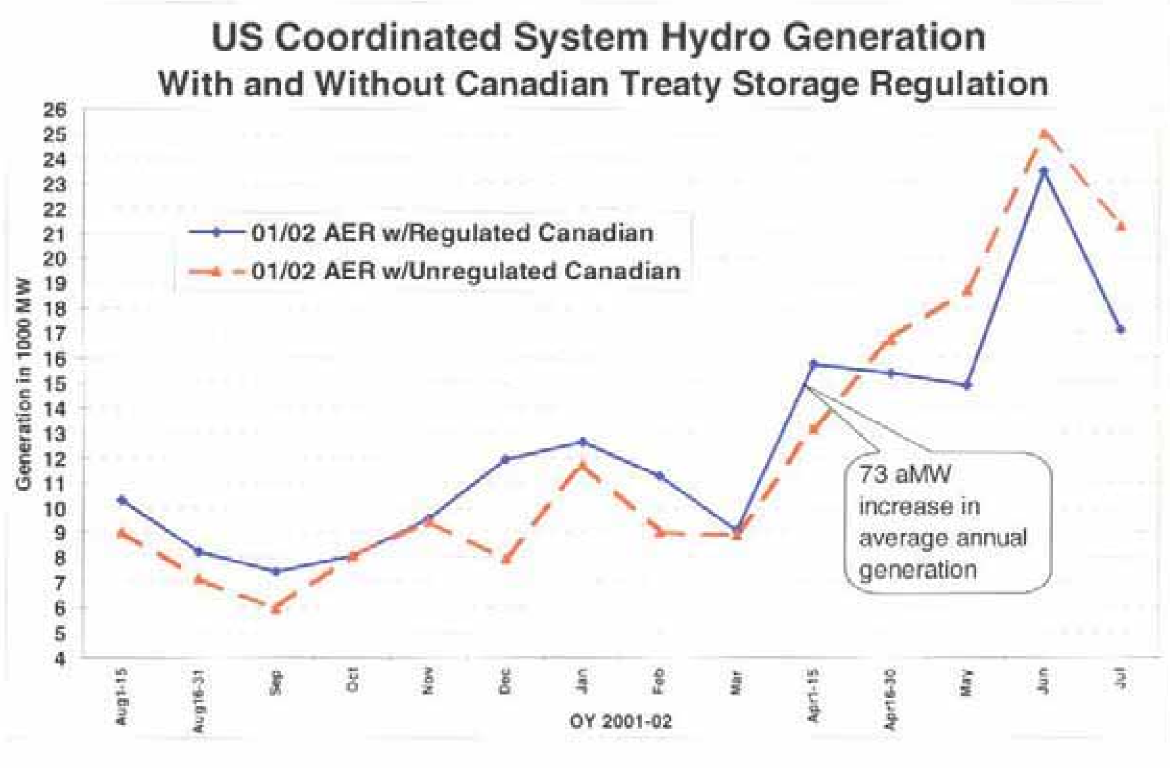
Note: 1999 through 2003 CSPE results adjusted to take out expire of 30yr sale.

Power Generation and other Accomplishments

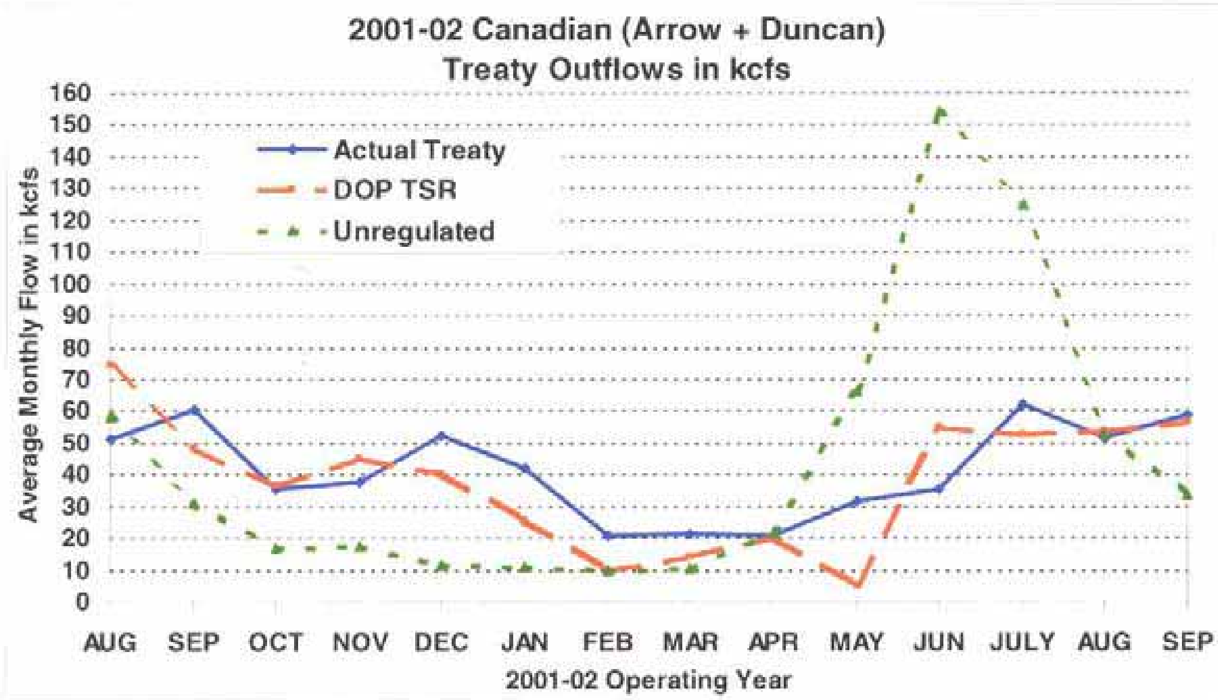
At the beginning of the 2001-02 operating year, the TSR storage level for Canadian storage was only 49.9 percent full, and the Coordinated System storage level was 67.1 percent full as measured in the PNCA AER which includes the Canadian Storage operation from the TSR study. Actual Canadian storage levels on 31 July 2001 were 65.7 percent full due to a supplemental operating agreement for summer storage. Due to the record low unregulated streamflows during the prior operating year, the hydro system continued to draft proportionally well below the ORC through April in order to create the firm load carrying capability determined in the critical period studies. During May through July most of the coordinated system recovered to the ORC, with the main exception of Mica which was limited by minimum flow requirements. Actual Canadian storage on 31 July 2002 reached 91.3 percent full, and the TSR storage level for Canadian storage was 91.8 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 2001-02 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 73 aMW. This power benefit would have been 176 aMW if measured without U.S. fishery requirements.

However, average annual changes in U.S. system generation do not highlight the large role Treaty storage played during and after the 2001 low runoff conditions. Treaty storage in the TSR drafted from full to empty during 16 August 2000 through 31 March 2002, and remained essentially empty through 30 April 2002. The unregulated streamflows at The Dalles during this period were only 0.8 percent higher than the historic record two year critical period which was 1 September 1943 through 30 April 1945. Measured over the period 16 August 2000 through 30 April 2002, U.S. system generation in the AER was increased by about 928 aMW by the operation of Canadian Treaty storage. This power benefit would have been about 1,173 aMW if measured without U.S. fishery requirements.



Based on the authority from the 2001-02 and 2002-03 DOP's, 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 increased reservoir levels for summer recreation, dust storm avoidance, and 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 2001, the sum of Canadian Treaty storage was positioned approximately 3,719 hm^3 (1,520 ksfd) above the DOP TSR. The U.S. Entity had about 3,817 hm^3 (1,560 ksfd) of storage remaining under the Summer Treaty Storage (STS) Agreement, and the Canadian Entity had drafted approximately 98 hm^3 (40 ksfd) under the terms of the LCA.

In October 2001, the U.S. utilized the STS and the STS Addendum Agreements and Canada provisionally drafted under the LCA, such that the sum of Canadian Treaty storage was approximately 3,915 hm^3 (1,600 ksfd) above the DOP TSR. During November and December the U.S. continued to exercise flexibility to store and release under the STS Agreements and Canada utilized provisional draft under the LCA. The sum of Treaty storage finished the calendar year at 3,670 hm^3 (1,500 ksfd) above the DOP TSR.

Beginning January 2002, Arrow's actual discharge was reduced to about 906.1 m^3/s (32,000 cfs) and Canada and the U.S. agreed to shape flow from January through April to meet multiple system requirements and fishery needs. From mid-January through late March, Arrow's actual discharge was maintained between 679.6 m^3/s and 736.2 m^3/s (24,000 cfs and 26,000 cfs) to protect whitefish in accordance with the Nonpower Uses Agreement. In February, the U.S. converted 1,233 hm^3 (504 ksfd) of storage in the STS Accounts to Flow Augmentation Storage under the Nonpower Uses Agreement. Beginning in March, discharge from Arrow was set to 425 m^3/s (15,000 cfs) to balance the needs of B.C. trout spawning, U.S. Vernita Bar requirements, and system load requirements. By the end of March, all provisional draft was returned, all remaining STS storage had been released, and the sum of Treaty storage was 1,223 hm^3 (500 ksfd) above TSR levels for flow augmentation. In May, Arrow discharge was increased to 566 m^3/s (20,000 cfs) to meet U.S. fishery requirements. Because of delayed runoff, Treaty storage projects were drafted a total of 930 hm^3 (380 ksfd) below TSR by the end of May. As streamflows increased, Treaty projects filled to near TSR levels by the end of July.

During August 2002, actual outflows from Arrow were maintained at a fairly constant level to accommodate research work downstream from the project. In addition, water was released from Canadian Treaty storage to try to balance the water stored in Libby under the Libby Storage Exchange Agreement.

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TABLES

Table 1: Unregulated Runoff Volume Forecasts

Million of Acre-feet
2002

Most Probable 1 April through 31 August Forecast in Maf

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	1.94	22.1	10.6	6.06	86.9
February	1.93	21.7	10.4	6.01	88.0
March	2.00	21.5	10.3	5.92	86.2
April	1.99	21.6	10.5	6.30	87.8
May	1.98	21.9	10.6	6.22	89.7
June	2.00	22.0	10.7	6.70	91.6
Actual	2.29	23.2	11.6	7.10	93.8

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

Table 1M: Unregulated Runoff Volume Forecasts

Cubic Kilometers
2002

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	2.39	27.3	13.1	7.48	107.2
February	2.38	26.8	12.8	7.41	108.5
March	2.47	26.5	12.7	7.30	106.3
April	2.45	26.6	13.0	7.77	108.3
May	2.44	27.0	13.1	7.67	110.6
June	2.47	27.1	13.2	8.26	113.0
Actual	2.82	28.6	14.3	8.76	115.7

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

Table 2: 2002 Variable Refill Curve Mica Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			8812.7	8618.3	8291.4	8299.8	7899.3	6312.7
PROBABLE DATE-31JULY INFLOW, KSFD	**		4443.0	4345.0	4180.2	4184.4	3982.5	3182.6
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/		3790.0	3834.6	3714.8	3739.9	3622.0	2822.1
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		3790.0					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1827.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1566.2					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2430.4					
JAN31 ORC, FT	7/		2430.4					
BASE ECC, FT	8/	2430.4						
LOWER LIMIT, FT		2409.4						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.6	97.6				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		3699.0	3742.5				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		8000.0	8000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1743.0	1743.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1573.2	1529.7				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2430.6	2429.7				
FEB28 ORC, FT	7/		2430.6	2429.7				
BASE ECC, FT	8/	2441.7						
LOWER LIMIT, FT		2403.9						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.1	95.1	97.4			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		3604.3	3646.7	3618.2			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		10000.0	10000.0	10000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1650.0	1650.0	1650.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1574.9	1532.5	1561.0			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2430.6	2429.7	2430.4			
MAR31 ORC, FT	7/		2428.4	2428.4	2428.4			
BASE ECC, FT	8/	2428.4						
LOWER LIMIT, FT		2394.1						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90.0	90.0	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		3411.0	3451.1	3425.1	3541.6		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		12000.0	12000.0	12000.0	12000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1380.0	1380.0	1380.0	1380.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1498.2	1458.1	1484.1	1367.6		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2429.0	2428.1	2428.7	2426.1		
APR30 ORC, FT	7/		2420.8	2420.8	2420.8	2420.8		
BASE ECC, FT	8/	2420.8						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		2713.6	2745.5	2723.0	2816.1	2879.5	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		15000.0	15000.0	15000.0	15000.0	15000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		1008.0	1008.0	1008.0	1008.0	1008.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		1823.6	1791.7	1814.2	1721.1	1657.7	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2435.9	2435.3	2435.8	2433.8	2432.4	
MAY31 ORC, FT	7/		2425.0	2425.0	2425.0	2425.0	2425.0	
BASE ECC, FT	8/	2425.0						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			35.5	35.5	36.3	37.3	39.4	49.5
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1345.4	1361.3	1348.5	1395.0	1427.1	1397.0
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		18000.0	18000.0	18000.0	18000.0	18000.0	18000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		558.0	558.0	558.0	558.0	558.0	558.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2741.8	2725.9	2738.7	2692.2	2660.1	2690.2
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2454.8	2454.6	2454.7	2453.8	2453.2	2453.7
JUN30 ORC, FT	7/		2449.2	2449.2	2449.2	2449.2	2449.2	2449.2
BASE ECC, FT	8/	2449.2						
JUL 31 ORC, FT			2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

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

Table 2M: 2002 Variable Refill Curve Mica Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KM^3			10.870	10.631	10.228	10.238	9.744	7.787
PROBABLE DATE-31JULY INFLOW, HM^3	**		10870.2	10630.5	10227.3	10237.6	9743.6	7786.6
95% FORECAST ERROR FOR DATE, HM^3			1597.7	1248.9	1138.6	1087.6	881.9	881.9
95% CONF.DATE-31JULY INFLOW, HM^3	1/		9272.6	9381.6	9088.7	9149.9	8861.6	6904.7
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		9272.6					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		84.95					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/		4469.9					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		3831.9					
VRC JAN31 RESERVOIR CONTENT, M	6/		740.79					
JAN31 ORC, M	7/		740.79					
BASE ECC, M	8/	740.79						
LOWER LIMIT, M		734.39						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.6	97.6				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		9050.0	9156.4				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		226.53	226.53				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		4264.4	4264.4				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		3849.0	3742.6				
VRC FEB28 RESERVOIR CONTENT, M	6/		740.85	740.57				
FEB28 ORC, M	7/		740.85	740.57				
BASE ECC, M	8/	744.23						
LOWER LIMIT, M		732.71						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.1	95.1	97.4			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		8818.3	8922.0	8852.3			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		283.17	283.17	283.17			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		4036.9	4036.9	4036.9			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		3853.2	3749.4	3819.1			
VRC MAR31 RESERVOIR CONTENT, M	6/		740.85	740.57	740.79			
MAR31 ORC, M	7/		740.18	740.18	740.18			
BASE ECC, M	8/	740.18						
LOWER LIMIT, M		729.72						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90.0	90.0	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		8345.4	8443.5	8379.8	8664.9		
MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		339.80	339.80	339.80	339.80		
MIN MAY1-JUL31 OUTFLOW, HM^3	4/		3376.3	3376.3	3376.3	3376.3		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		3665.5	3567.4	3631.0	3346.0		
VRC APR30 RESERVOIR CONTENT, M	6/		740.36	740.08	740.27	739.48		
APR30 ORC, M	7/		737.86	737.86	737.86	737.86		
BASE ECC, M	8/	737.86						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		6639.1	6717.1	6662.1	6889.9	7045.0	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		424.75	424.75	424.75	424.75	424.75	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		2466.2	2466.2	2466.2	2466.2	2466.2	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		4461.6	4383.6	4438.6	4210.8	4055.7	
VRC MAY31 RESERVOIR CONTENT, M	6/		742.46	742.28	742.43	741.82	741.40	
MAY31 ORC, M	7/		739.14	739.14	739.14	739.14	739.14	
BASE ECC, M	8/	739.14						
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/		3291.7	3330.6	3299.2	3413.0	3491.5	3417.9
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		509.70	509.70	509.70	509.70	509.70	509.70
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		1365.2	1365.2	1365.2	1365.2	1365.2	1365.2
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		6708.1	6669.2	6700.5	6586.7	6508.2	6581.8
VRC JUN30 RESERVOIR CONTENT, M	6/		748.22	748.16	748.19	747.92	747.74	747.89
JUN30 ORC, M	7/		746.52	746.52	746.52	746.52	746.52	746.52
BASE ECC, M	8/	746.52						
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 (8634.5 HM^3) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 3: 2002 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			19406.6	19043.6	18356.1	17830.2	16773.4	12576.5
& IN KSFD	**		9784.0	9601.0	9254.4	8989.3	8456.5	6340.5
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/		8550.6	8613.7	8429.2	8273.7	7954.8	5838.8
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		8550.6					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		3809.0					
UPSTREAM DISCHARGE, KSFD	4/		1963.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		801.0					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1395.7					
JAN31 ORC, FT	7/		1395.7					
BASE ECC, FT	8/	1444.0						
LOWER LIMIT, FT		1395.0						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.5	97.5				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		8336.8	8398.4				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		3669.0	3669.0				
UPSTREAM DISCHARGE, KSFD	4/		1956.0	1999.5				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		867.8	849.7				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1397.1	1396.7				
FEB28 ORC, FT	7/		1397.1	1396.7				
BASE ECC, FT	8/	1439.5						
LOWER LIMIT, FT		1388.0						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.4	94.4	96.9			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		8071.8	8131.4	8167.9			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		3514.0	3514.0	3514.0			
UPSTREAM DISCHARGE, KSFD	4/		2057.0	2057.0	2057.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1078.8	1019.2	982.7			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1401.3	1400.1	1399.4			
MAR31 ORC, FT	7/		1401.3	1400.1	1399.4			
BASE ECC, FT	8/	1431.8						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.5	87.5	89.8	92.6		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		7481.8	7537.0	7569.4	7661.4		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		3094.0	3094.0	3094.0	3094.0		
UPSTREAM DISCHARGE, KSFD	4/		2401.9	2401.9	2401.9	2401.9		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1593.7	1538.5	1506.1	1414.1		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1411.0	1410.0	1409.4	1407.7		
APR30 ORC, FT	7/		1411.0	1410.0	1409.4	1407.7		
BASE ECC, FT	8/	1422.7						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.5	65.5	67.2	69.3	74.9	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		5600.6	5642.0	5664.4	5733.7	5958.1	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		2257.0	2257.0	2257.0	2257.0	2257.0	
UPSTREAM DISCHARGE, KSFD	4/		2214.1	2214.1	2214.1	2214.1	2214.1	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2450.1	2408.7	2386.3	2317.0	2092.6	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1426.0	1425.3	1424.9	1423.7	1419.9	
MAY31 ORC, FT	7/		1426.0	1425.3	1424.9	1423.7	1419.9	
BASE ECC, FT	8/	1430.8						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.3	30.3	31.1	32.1	34.7	46.3
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		2590.8	2610.0	2621.5	2655.9	2760.3	2703.4
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		1147.0	1147.0	1147.0	1147.0	1147.0	1147.0
UPSTREAM DISCHARGE, KSFD	4/		1068.8	1068.8	1068.8	1068.8	1068.8	1068.8
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3204.6	3185.4	3173.9	3139.5	3035.1	3092.0
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1438.2	1437.9	1437.7	1437.2	1435.5	1436.4
JUN30 ORC, FT	7/		1438.2	1437.9	1437.7	1437.2	1435.5	1436.4
BASE ECC, FT	8/	1430.0						
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: 2002 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			23.938	23.490	22.642	21.994	20.690	15.513
& IN HM^3	**		23937.5	23489.8	22641.8	21993.1	20689.6	15512.8
95% FORECAST ERROR FOR DATE, IN HM^3			3017.7	2415.5	2018.9	1750.7	1227.5	1227.5
95% CONF.DATE-31JULY INFLOW, HM^3	1/		20919.9	21074.4	20622.9	20242.4	19462.2	14285.3
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		20919.9					
MIN FEB1-JUL31 OUTFLOW, HM^3	3/		9319.1					
UPSTREAM DISCHARGE, HM^3	4/		4802.7					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		1959.7					
VRC JAN31 RESERVOIR CONTENT, M	6/		425.41					
JAN31 ORC, M	7/		425.41					
BASE ECC, M	8/	440.13						
LOWER LIMIT, M		425.20						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.5	97.5				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		20396.8	20547.5				
MIN MAR1-JUL31 OUTFLOW, HM^3	3/		8976.6	8976.6				
UPSTREAM DISCHARGE, HM^3	4/		4785.5	4892.0				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		2123.2	2078.9				
VRC FEB28 RESERVOIR CONTENT, M	6/		425.84	425.71				
FEB28 ORC, M	7/		425.84	425.71				
BASE ECC, M	8/	438.76						
LOWER LIMIT, M		423.06						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.4	94.4	96.9			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		19748.5	19894.3	19983.6			
MIN APR1-JUL31 OUTFLOW, HM^3	3/		8597.4	8597.4	8597.4			
UPSTREAM DISCHARGE, HM^3	4/		5032.7	5032.7	5032.7			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		2639.4	2493.6	2404.3			
VRC MAR31 RESERVOIR CONTENT, M	6/		427.12	426.75	426.54			
MAR31 ORC, M	7/		427.12	426.75	426.54			
BASE ECC, M	8/	436.41						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.5	87.5	89.8	92.6		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		18305.0	18440.0	18519.3	18744.4		
MIN MAY1-JUL31 OUTFLOW, HM^3	3/		7569.8	7569.8	7569.8	7569.8		
UPSTREAM DISCHARGE, HM^3	4/		5876.5	5876.5	5876.5	5876.5		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		3899.1	3764.1	3684.8	3459.7		
VRC APR30 RESERVOIR CONTENT, M	6/		430.07	429.77	429.59	429.07		
APR30 ORC, M	7/		430.07	429.77	429.59	429.07		
BASE ECC, M	8/	433.64						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			65.5	65.5	67.2	69.3	74.9	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		13702.4	13803.7	13858.5	14028.1	14577.1	
MIN JUN1-JUL31 OUTFLOW, HM^3	3/		5522.0	5522.0	5522.0	5522.0	5522.0	
UPSTREAM DISCHARGE, HM^3	4/		5417.0	5417.0	5417.0	5417.0	5417.0	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		5994.4	5893.1	5838.3	5668.8	5119.8	
VRC MAY31 RESERVOIR CONTENT, M	6/		434.64	434.43	434.31	433.94	432.78	
MAY31 ORC, M	7/		434.64	434.43	434.31	433.94	432.78	
BASE ECC, M	8/	436.11						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.3	30.3	31.1	32.1	34.7	46.3
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		6338.7	6385.6	6413.8	6497.9	6753.3	6614.1
MIN JUL1-JUL31 OUTFLOW, HM^3	3/		2806.3	2806.3	2806.3	2806.3	2806.3	2806.3
UPSTREAM DISCHARGE, HM^3	4/		2614.9	2614.9	2614.9	2614.9	2614.9	2614.9
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		7840.4	7793.4	7765.3	7681.1	7425.7	7564.9
VRC JUN30 RESERVOIR CONTENT, M	6/		438.36	438.27	438.21	438.06	437.54	437.81
JUN30 ORC, M	7/		438.36	438.27	438.21	438.06	437.54	437.81
BASE ECC, M	8/	435.86						
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 (8757.8 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: 2002 Variable Refill Curve Duncan Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			1672.1	1664.2	1679.9	1623.7	1514.5	1157.2
& IN KSFD	**		843.0	839.0	846.9	818.6	763.6	583.4
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/		724.6	730.1	749.4	730.5	690.2	510.1
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		724.6					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		202.9					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		184.1					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1826.7					
JAN31 ORC, FT	7/		1826.7					
BASE ECC, FT	8/	1845.5						
LOWER LIMIT, FT		1806.1						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		708.7	714.0				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		200.1	200.1				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		197.2	191.9				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1828.6	1827.8				
FEB28 ORC, FT	7/		1813.3	1813.9				
BASE ECC, FT	8/	1841.7						
LOWER LIMIT, FT		1798.1						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		690.6	695.7	729.9			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		197.0	197.0	197.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		212.2	207.1	172.9			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1830.7	1829.9	1825.0			
MAR31 ORC, FT	7/		1813.3	1813.9	1807.8			
BASE ECC, FT	8/	1837.6						
LOWER LIMIT, FT		1794.0						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.2	89.2	91.1	93.5		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		646.4	651.2	682.7	683.0		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		600.0	600.0	600.0	600.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		189.5	189.5	189.5	189.5		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		248.9	244.1	212.6	212.3		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1835.8	1835.1	1830.7	1830.6		
APR30 ORC, FT	7/		1813.3	1813.9	1807.8	1808.7		
BASE ECC, FT	8/	1835.4						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		489.9	493.5	517.9	517.9	523.2	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		2700.0	2700.0	2700.0	2700.0	2700.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		170.9	170.9	170.9	170.9	170.9	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		386.8	383.2	358.8	358.8	353.5	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1854.0	1853.6	1850.6	1850.6	1849.9	
MAY31 ORC, FT	7/		1850.7	1850.7	1850.6	1850.6	1849.9	
BASE ECC, FT	8/	1850.7						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			31.7	31.7	32.4	33.3	35.6	1.0
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		229.7	231.4	242.8	243.3	245.7	239.2
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		2900.0	2900.0	2900.0	2900.0	2900.0	2900.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		89.9	89.9	89.9	89.9	89.9	89.9
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		566.0	564.3	552.9	552.4	550.0	556.5
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1876.0	1875.7	1874.4	1874.3	1874.0	1874.8
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: 2002 Variable Refill Curve Duncan Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KM^3			2.063	2.053	2.072	2.003	1.868	1.427
& IN HM^3	**		2062.5	2052.7	2072.1	2002.9	1868.1	1427.3
95% FORECAST ERROR FOR DATE, IN HM^3			289.6	266.6	238.6	215.5	179.3	179.3
95% CONF.DATE-31JULY INFLOW, HM^3	1/		1772.9	1786.1	1833.6	1787.3	1688.8	1248.0
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		1772.8					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		2.83					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/		496.4					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		450.4					
VRC JAN31 RESERVOIR CONTENT, M	6/		556.78					
JAN31 ORC, M	7/		556.78					
BASE ECC, M	8/	562.51						
LOWER LIMIT, M		550.50						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		1733.9	1746.9				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		2.83	2.83				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		489.6	489.6				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		482.5	469.5				
VRC FEB28 RESERVOIR CONTENT, M	6/		557.36	557.11				
FEB28 ORC, M	7/		552.69	552.88				
BASE ECC, M	8/	561.35						
LOWER LIMIT, M		548.06						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		1689.6	1702.1	1785.8			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		2.83	2.83	2.83			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		482.0	482.0	482.0			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		519.2	506.7	423.0			
VRC MAR31 RESERVOIR CONTENT, M	6/		558.00	557.75	556.26			
MAR31 ORC, M	7/		552.69	552.88	551.02			
BASE ECC, M	8/	560.10						
LOWER LIMIT, M		546.81						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.2	89.2	91.1	93.5		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		1581.5	1593.2	1670.3	1671.0		
MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		16.99	16.99	16.99	16.99		
MIN MAY1-JUL31 OUTFLOW, HM^3	4/		463.6	463.6	463.6	463.6		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		609.0	597.2	520.1	519.4		
VRC APR30 RESERVOIR CONTENT, M	6/		559.55	559.34	558.00	557.97		
APR30 ORC, M	7/		552.69	552.88	551.02	551.29		
BASE ECC, M	8/	559.43						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		1198.6	1207.4	1267.1	1267.1	1280.1	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		76.46	76.46	76.46	76.46	76.46	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		418.1	418.1	418.1	418.1	418.1	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		946.3	937.5	877.8	877.8	864.9	
VRC MAY31 RESERVOIR CONTENT, M	6/		565.10	564.98	564.06	564.06	563.85	
MAY31 ORC, M	7/		564.09	564.09	564.06	564.06	563.85	
BASE ECC, M	8/	564.09						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			31.7	31.7	32.4	33.3	35.6	1.0
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		562.0	566.1	594.0	595.3	601.1	585.2
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		82.12	82.12	82.12	82.12	82.12	82.12
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		219.9	219.9	219.9	219.9	219.9	219.9
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		1384.8	1380.6	1352.7	1351.5	1345.6	1361.5
VRC JUN30 RESERVOIR CONTENT, M	6/		571.80	571.71	571.32	571.29	571.20	571.44
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 (1726.8 HM^3) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), NOT LESS THAN LOWER LIMIT, BUT NOT MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 5: 2002 Variable Refill Curve Libby Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			6115.6	6064.4	5970.0	6278.1	6206.0	6643.0
PROBABLE DATE-31JULY INFLOW, KSFD			3083.3	3057.5	3009.9	3165.2	3128.9	3349.2
95% FORECAST ERROR FOR DATE, KSFD			886.8	606.4	552.5	533.4	474.5	367.5
OBSERVED JAN1-DATE INFLOW, IN KSFD			0.0	101.3	191.1	279.8	515.3	1248.3
95% CONF.DATE-31JULY INFLOW, KSFD	1/		2196.5	2349.7	2266.3	2352.0	2139.1	1733.4
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			97.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		2129.7					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1107.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1487.8					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2410.2					
JAN31 ORC, FT	7/		2410.2					
BASE ECC, FT	9/	2418.1						
LOWER LIMIT, FT		2383.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.2	97.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		2068.7	2282.5				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		995.0	995.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1436.8	1223.0				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2407.3	2394.5				
FEB28 ORC, FT	7/		2407.3	2394.5				
BASE ECC, FT	9/	2415.4						
LOWER LIMIT, FT		2342.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.8	93.7	96.4			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		1994.6	2200.7	2185.1			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0	4000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		871.0	871.0	871.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1386.9	1180.8	1196.4			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2404.4	2391.8	2392.8			
MAR31 ORC, FT	7/		2404.4	2391.8	2392.8			
BASE ECC, FT	9/	2412.6						
LOWER LIMIT, FT		2295.3						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.7	85.3	87.8	91.1		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		1816.5	2004.1	1989.8	2142.0		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		7000.0	7000.0	7000.0	7000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		736.0	736.0	736.0	736.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1430.0	1242.4	1256.7	1104.5		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2406.9	2395.7	2396.6	2386.7		
APR30 ORC, FT	7/		2406.9	2395.7	2396.6	2386.7		
BASE ECC, FT	9/	2410.1						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.3	57.0	58.7	60.9	66.9	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		1214.2	1339.8	1330.3	1431.9	1430.0	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		8000.0	8000.0	8000.0	8000.0	8000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		519.0	519.0	519.0	519.0	519.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		1815.3	1689.7	1699.2	1597.6	1599.5	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2427.2	2420.9	2421.4	2416.0	2416.2	
MAY31 ORC, FT	7/		2427.2	2420.9	2421.4	2416.0	2416.2	
BASE ECC, FT	9/	2430.3						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.6	20.2	20.8	21.6	23.7	35.5
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		430.5	475.1	471.6	507.6	507.0	614.5
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		9000.0	9000.0	9000.0	9000.0	9000.0	9000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		279.0	279.0	279.0	279.0	279.0	279.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2359.0	2314.4	2317.9	2281.9	2282.5	2175.0
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2452.4	2450.5	2450.6	2449.0	2449.1	2444.2
JUN30 ORC, FT	7/		2452.4	2450.5	2450.6	2449.0	2449.1	2444.2
BASE ECC, FT	9/	2455.2						
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: 2002 Variable Refill Curve Libby Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KM^3			7.544	7.481	7.364	7.744	7.655	8.194
PROBABLE DATE-31JULY INFLOW, HM^3			7543.6	7480.5	7364.0	7744.0	7655.2	8194.2
95% FORECAST ERROR FOR DATE, HM^3			2169.6	1483.6	1351.7	1305.0	1160.9	899.1
OBSERVED JAN1-DATE INFLOW, IN HM^3			0.0	247.8	467.5	684.6	1260.7	3054.1
95% CONF.DATE-31JULY INFLOW, HM^3	1/		5374.0	5748.8	5544.7	5754.4	5233.5	4240.9
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			97.0					
ASSUMED FEB1-JUL31 INFLOW, HM^3	2/		5210.5					
FEB MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.3					
MIN FEB1-JUL31 OUTFLOW, HM^3	4/		2708.4					
VRC JAN31 RESERVOIR CONTENT, HM^3	5/		3640.1					
VRC JAN31 RESERVOIR CONTENT, M	6/		734.57					
JAN31 ORC, M	7/		734.57					
BASE ECC, M	9/	737.04						
LOWER LIMIT, M		726.55						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.2	97.1				
ASSUMED MAR1-JUL31 INFLOW, HM^3	2/		5061.3	5584.4				
MAR MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.3	113.3				
MIN MAR1-JUL31 OUTFLOW, HM^3	4/		2434.4	2434.4				
VRC FEB28 RESERVOIR CONTENT, HM^3	5/		3515.3	2992.2				
VRC FEB28 RESERVOIR CONTENT, M	6/		733.75	729.84				
FEB28 ORC, M	7/		733.75	729.84				
BASE ECC, M	9/	736.21						
LOWER LIMIT, M		713.96						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.8	93.7	96.4			
ASSUMED APR1-JUL31 INFLOW, HM^3	2/		4880.0	5384.2	5346.1			
APR MINIMUM FLOW REQUIREMENT, M^3/S	3/		113.3	113.3	113.3			
MIN APR1-JUL31 OUTFLOW, HM^3	4/		2131.0	2131.0	2131.0			
VRC MAR31 RESERVOIR CONTENT, HM^3	5/		3393.2	2888.9	2927.1			
VRC MAR31 RESERVOIR CONTENT, M	6/		732.86	729.02	729.33			
MAR31 ORC, M	7/		732.86	729.02	729.33			
BASE ECC, M	9/	735.36						
LOWER LIMIT, M		699.61						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.7	85.3	87.8	91.1		
ASSUMED MAY1-JUL31 INFLOW, HM^3	2/		4444.2	4903.2	4868.2	5240.6		
MAY MINIMUM FLOW REQUIREMENT, M^3/S	3/		198.2	198.2	198.2	198.2		
MIN MAY1-JUL31 OUTFLOW, HM^3	4/		1800.7	1800.7	1800.7	1800.7		
VRC APR30 RESERVOIR CONTENT, HM^3	5/		3498.6	3039.7	3074.6	2702.3		
VRC APR30 RESERVOIR CONTENT, M	6/		733.62	730.21	730.48	727.47		
APR30 ORC, M	7/		733.62	730.21	730.48	727.47		
BASE ECC, M	9/	734.60						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.3	57.0	58.7	60.9	66.9	
ASSUMED JUN1-JUL31 INFLOW, HM^3	2/		2970.7	3278.0	3254.7	3503.3	3498.6	
JUN MINIMUM FLOW REQUIREMENT, M^3/S	3/		226.5	226.5	226.5	226.5	226.5	
MIN JUN1-JUL31 OUTFLOW, HM^3	4/		1269.8	1269.8	1269.8	1269.8	1269.8	
VRC MAY31 RESERVOIR CONTENT, HM^3	5/		4441.3	4134.0	4157.3	3908.7	3913.3	
VRC MAY31 RESERVOIR CONTENT, M	6/		739.81	737.89	738.04	736.40	736.61	
MAY31 ORC, M	7/		739.81	737.89	738.04	736.40	736.61	
BASE ECC, M	9/	740.76						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.6	20.2	20.8	21.6	23.7	35.5
ASSUMED JUL1-JUL31 INFLOW, HM^3	2/		1053.3	1162.4	1153.8	1241.9	1240.4	1503.4
JUL MINIMUM FLOW REQUIREMENT, M^3/S	3/		254.8	254.8	254.8	254.8	254.8	254.8
MIN JUL1-JUL31 OUTFLOW, HM^3	4/		682.6	682.6	682.6	682.6	682.6	682.6
VRC JUN30 RESERVOIR CONTENT, HM^3	5/		5771.5	5662.4	5671.0	5582.9	5584.4	5321.4
VRC JUN30 RESERVOIR CONTENT, M	6/		747.49	746.91	746.94	746.46	746.49	744.99
JUN30 ORC, M	7/		747.49	746.91	746.94	746.46	746.49	744.99
BASE ECC, M	9/	748.34						
JUL 31 ORC, M			749.50	749.50	749.50	749.50	749.50	749.50
JAN1-JUL31 FORECAST,-EARLYBIRD, KM^3	8/		121.7	124.6	120.0	118.9	121.1	123.4

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 (6142.2 HM^3) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143
7/ LOWER OF ELEV. FROM 6/ OR BASE VRC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT
8/ MEASURED AT THE DALLES USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3/.
9/ HIGHER OF ARC OR CRC1 IN DOP

Table 6: Computation of Initial Controlled Flow

Columbia River at The Dalles
1 May 2002

1 May Forecast of May – August Unregulated Runoff Volume, Maf		76.100
Less Estimated Depletions, Maf		1.500
Less Upstream Storage Corrections, Maf		22.760
Mica	6.182	
Arrow	5.000	
Duncan	1.394	
Libby	3.012	
Libby + Duncan Under Draft	0.000	
Hungry Horse	1.140	
Flathead Lake	0.500	
Noxon Rapids	0.000	
Pend Oreille Lake	0.500	
Grand Coulee	3.214	
Brownlee	0.200	
Dworshak	1.312	
John Day	0.307	
Total	22.760	
Forecast of Adjusted Residual Runoff Volume, Maf		51.840
Computed Initial Control Flow from Chart 1 of Flood Control Operation Plan, 1,000 cfs		326

Table 6M: Computation of Initial Controlled Flow

Columbia River at The Dalles
1 May 2002

1 May Forecast of May – August Unregulated Runoff Volume - km^3		93.869
Less Estimated Depletions, km^3		1.850
Less Upstream Storage Corrections, km^3		28.075
Mica	7.625	
Arrow	6.168	
Duncan	1.719	
Libby	3.715	
Libby + Duncan Under Draft	0.000	
Hungry Horse	1.406	
Flathead Lake	0.617	
Noxon Rapids	0.000	
Pend Oreille Lake	0.617	
Grand Coulee	3.964	
Brownlee	0.247	
Dworshak	1.618	
John Day	0.379	
Total	28.075	
Forecast of Adjusted Residual Runoff Volume, km^3		63.944
Computed Initial Control Flow from Chart 1 of Flood Control Operation Plan, m^3/s		9,231.283

CHARTS

Chart 1: Seasonal Precipitation

Columbia River Basin
October 2001 - September 2002
Percent Of 1961 – 1990 Average

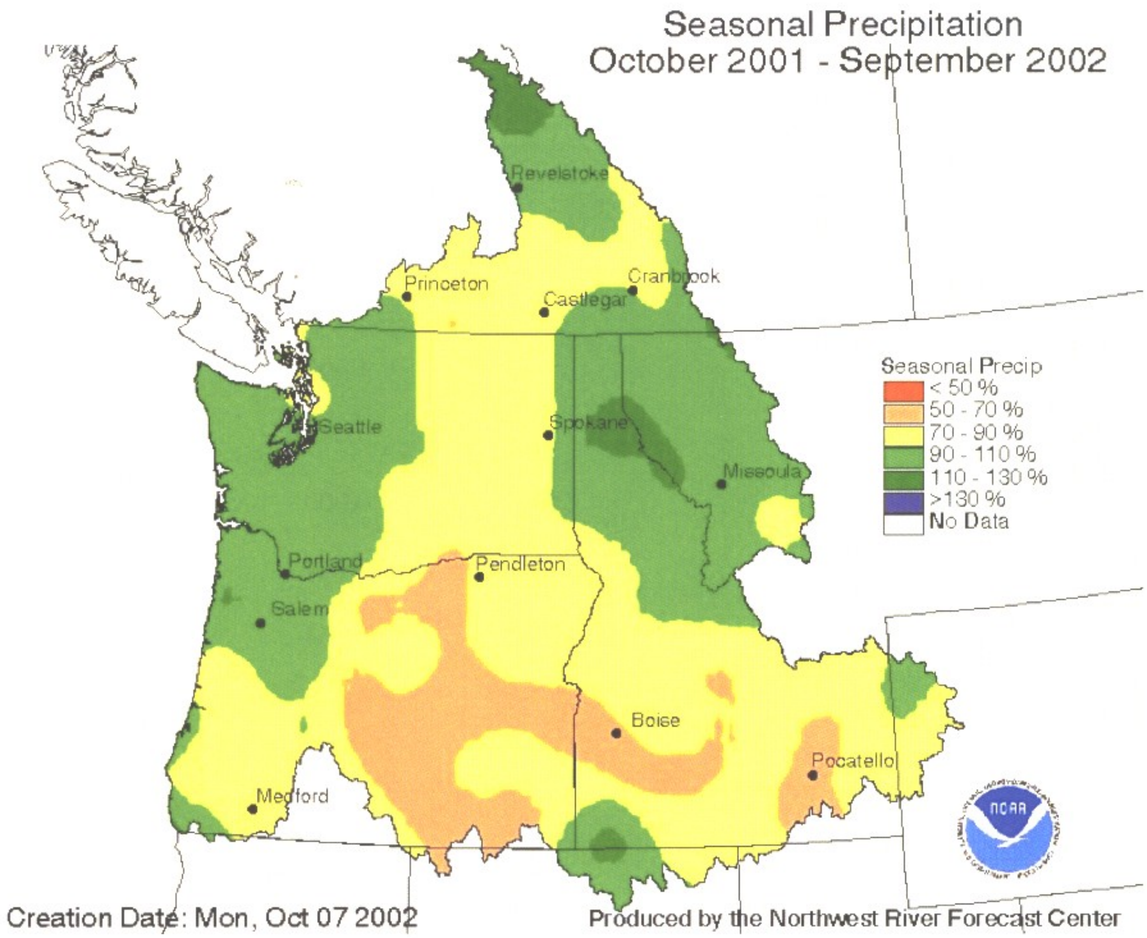


Chart 2: Columbia Basin Snowpack

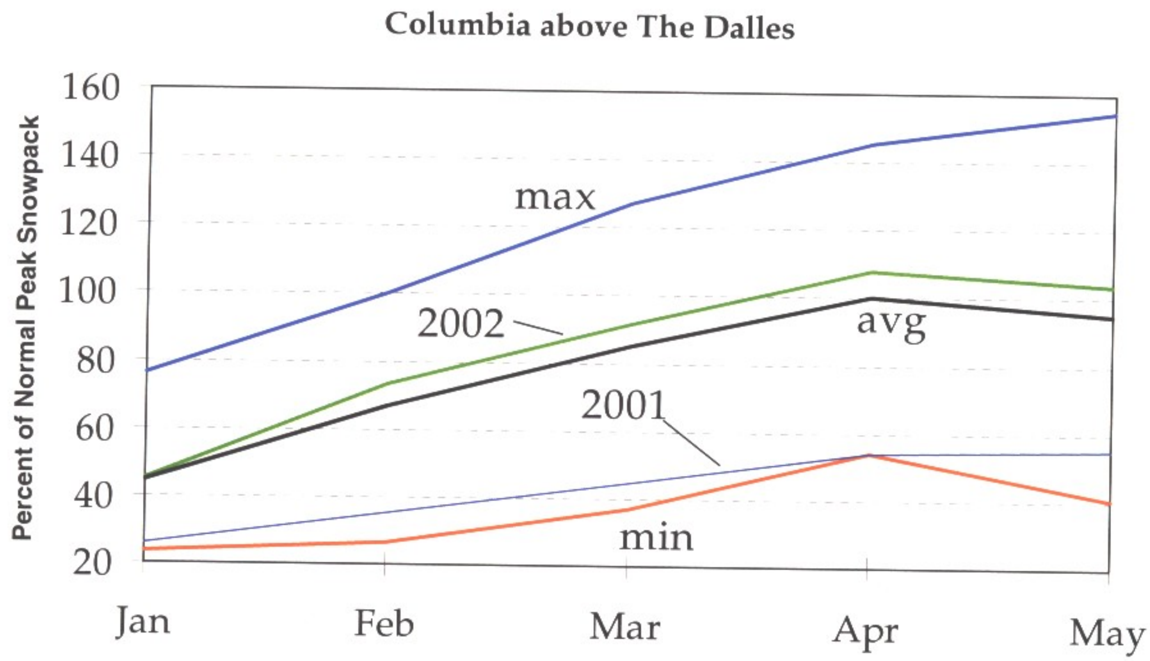


Chart 3: Accumulated Precipitation At Selected Basin

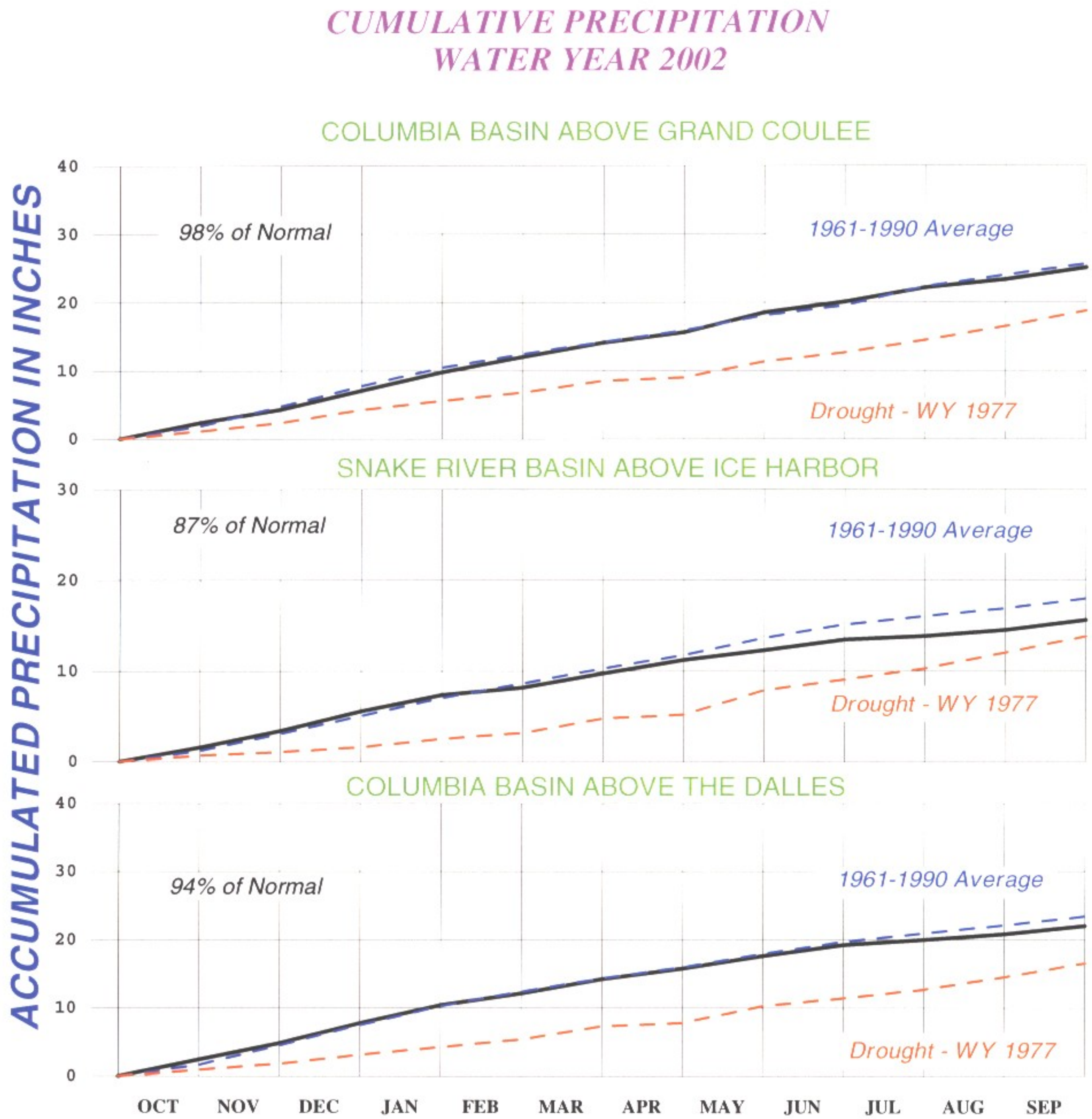
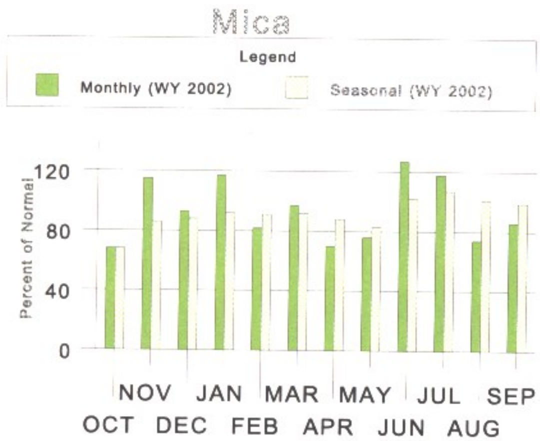
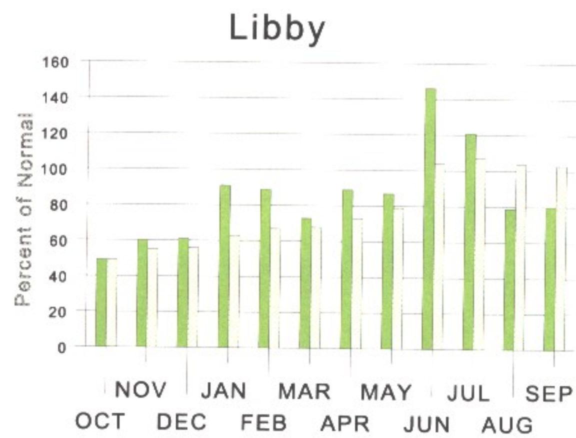
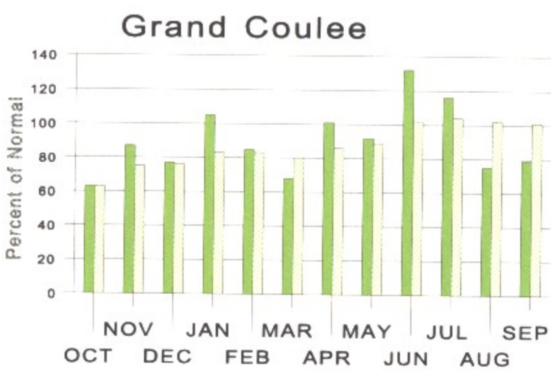


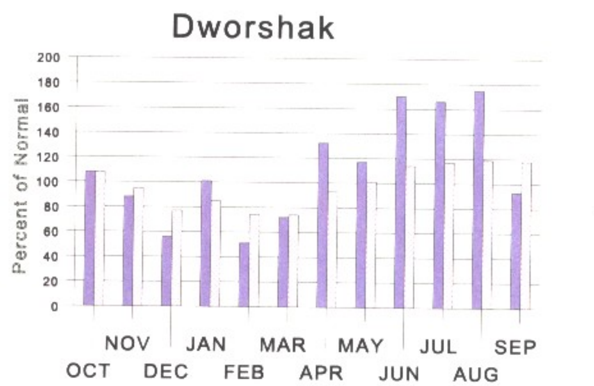
Chart 4: Reservoir Inflow

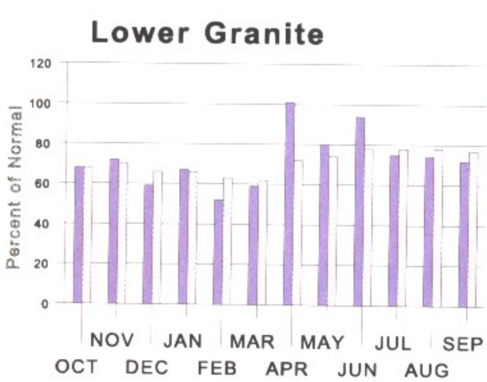
Monthly and Seasonal Reservoir Inflow at Key Indices Water Year 2002











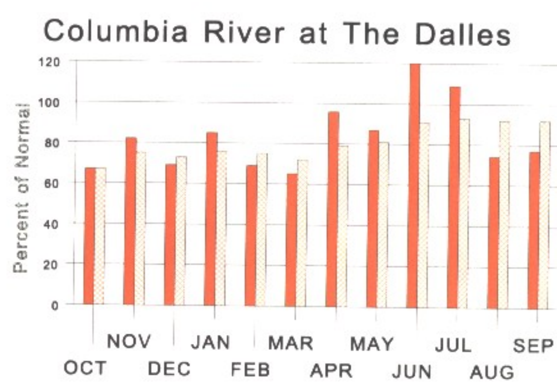
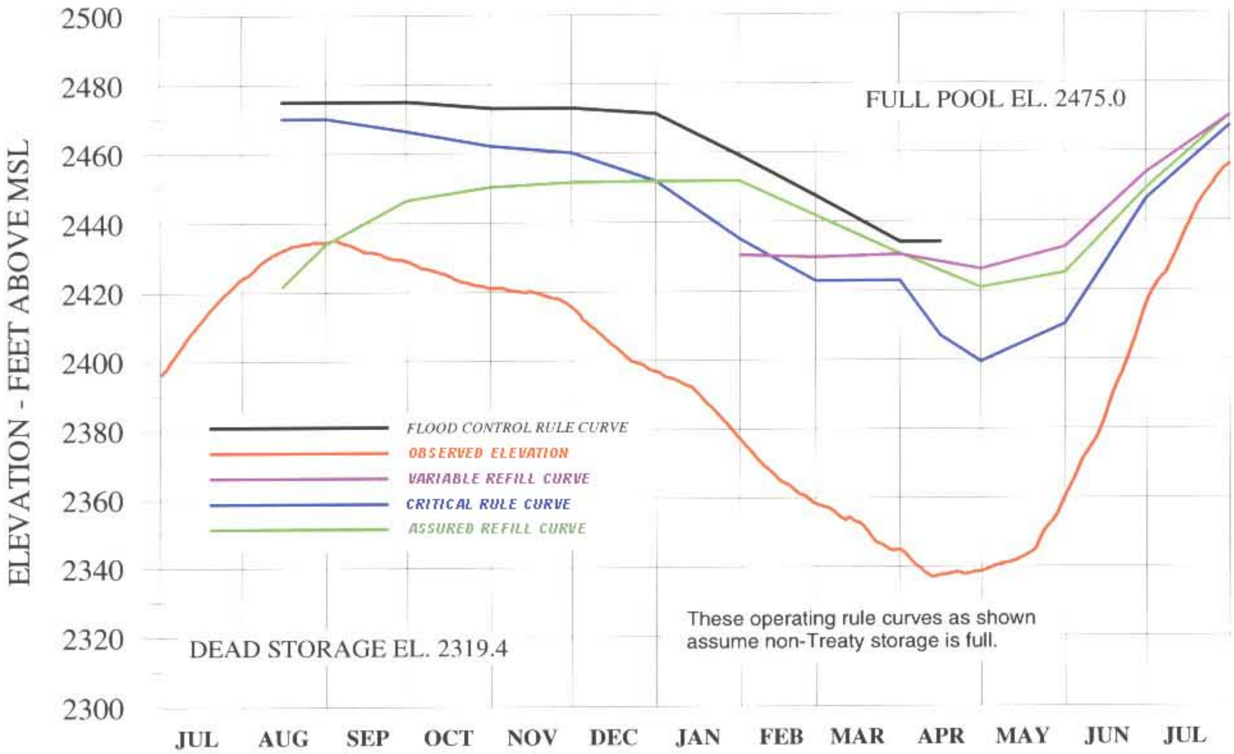


Chart 5: Regulation of Mica
1 July 2001 – 31 July 2002



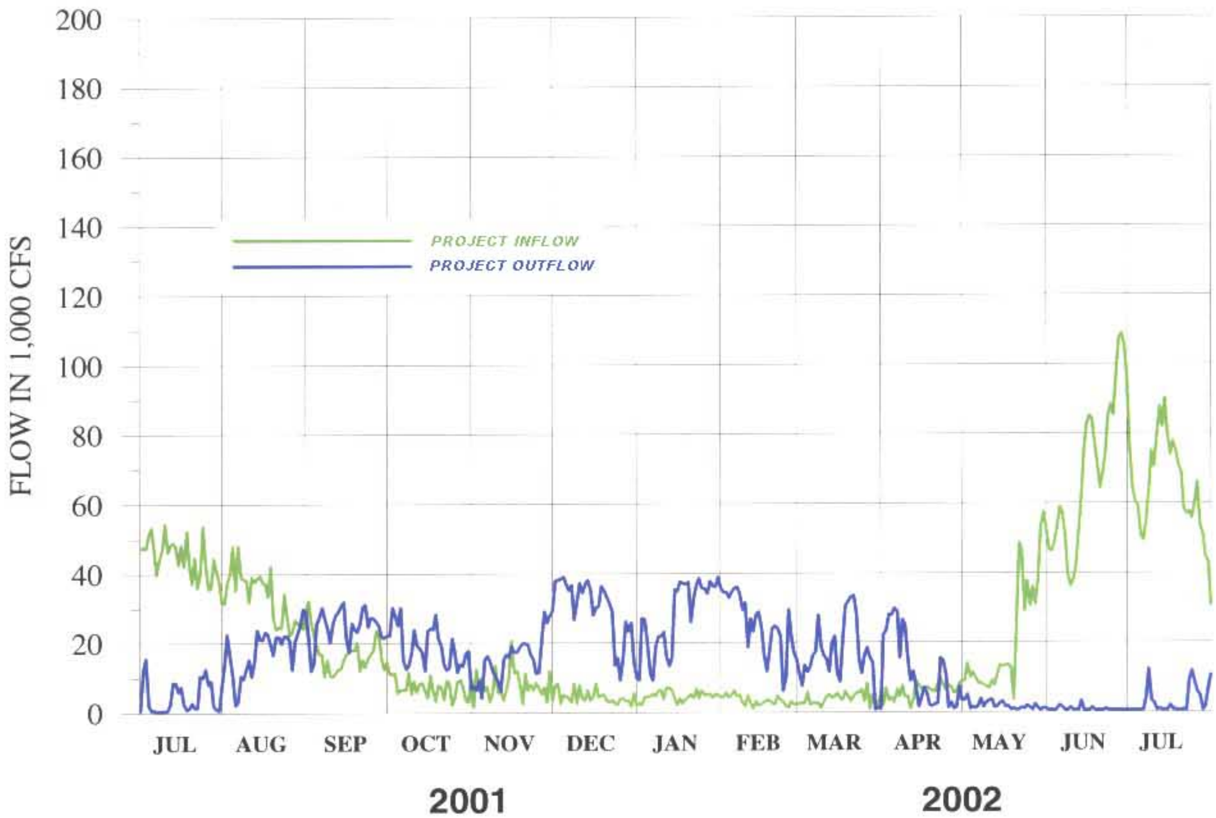
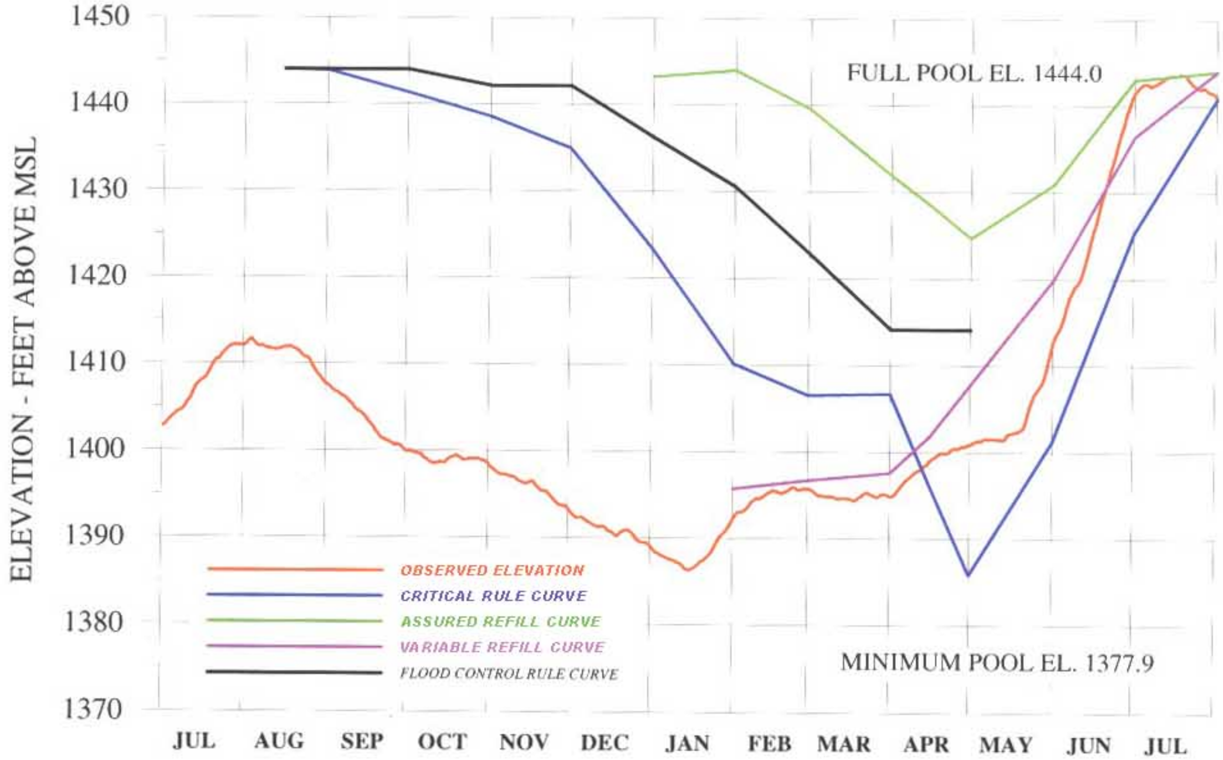


Chart 6: Regulation Of Arrow
1 July 2001 – 31 July 2002



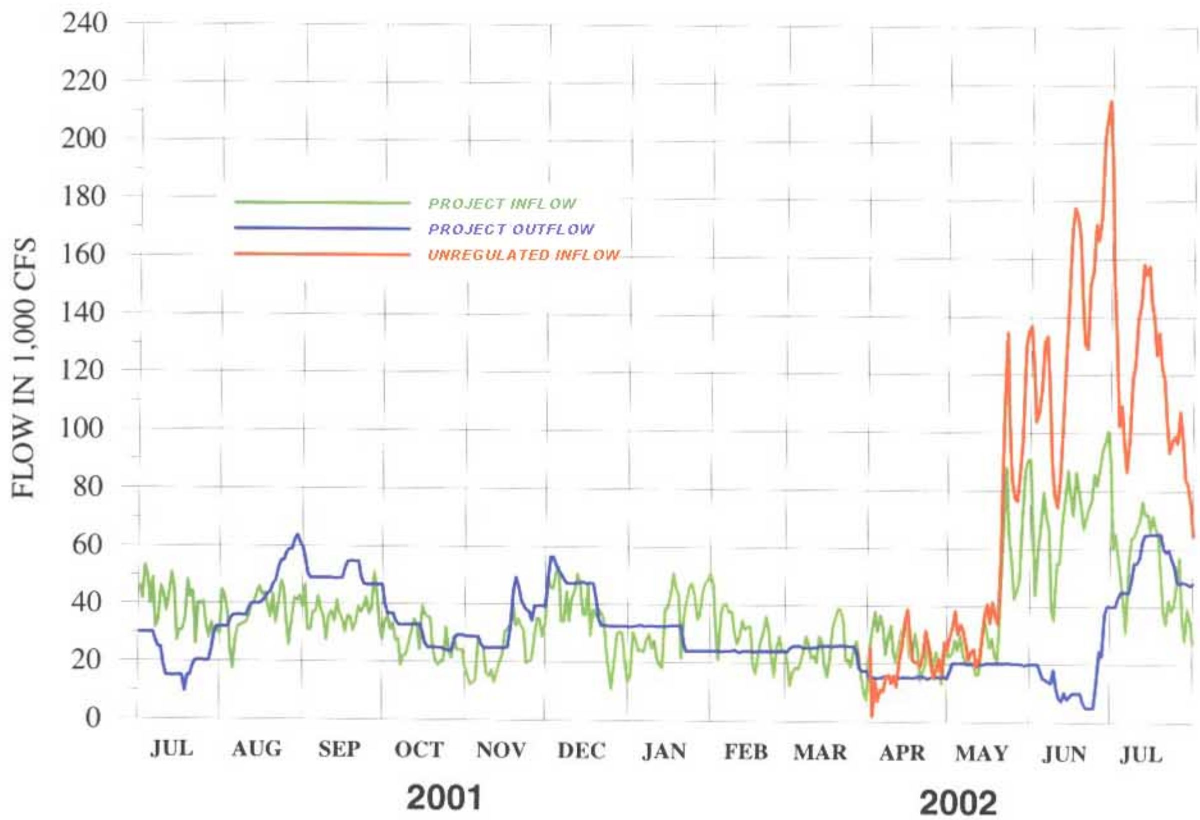
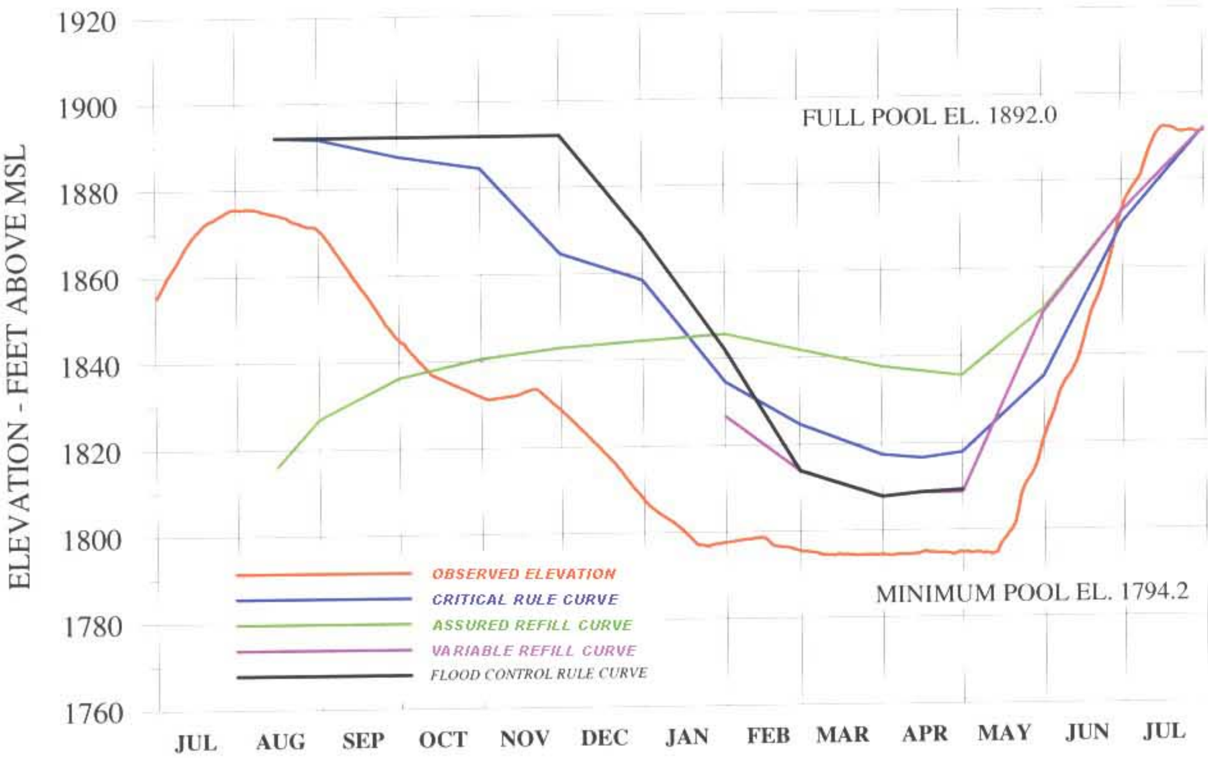


Chart 7: Regulation Of Duncan
1 July 2001 – 31 July 2002



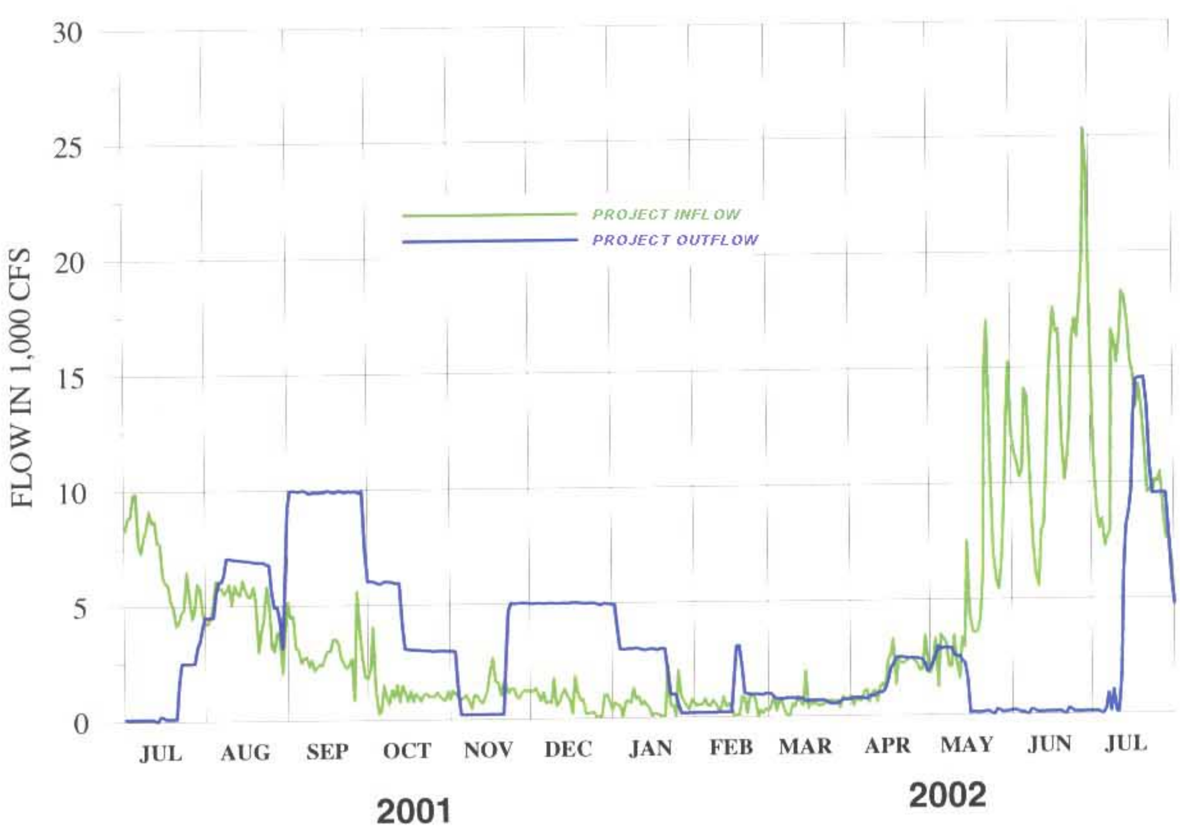


Chart 8: Regulation Of Libby
1 July 2001 – 31 July 2002

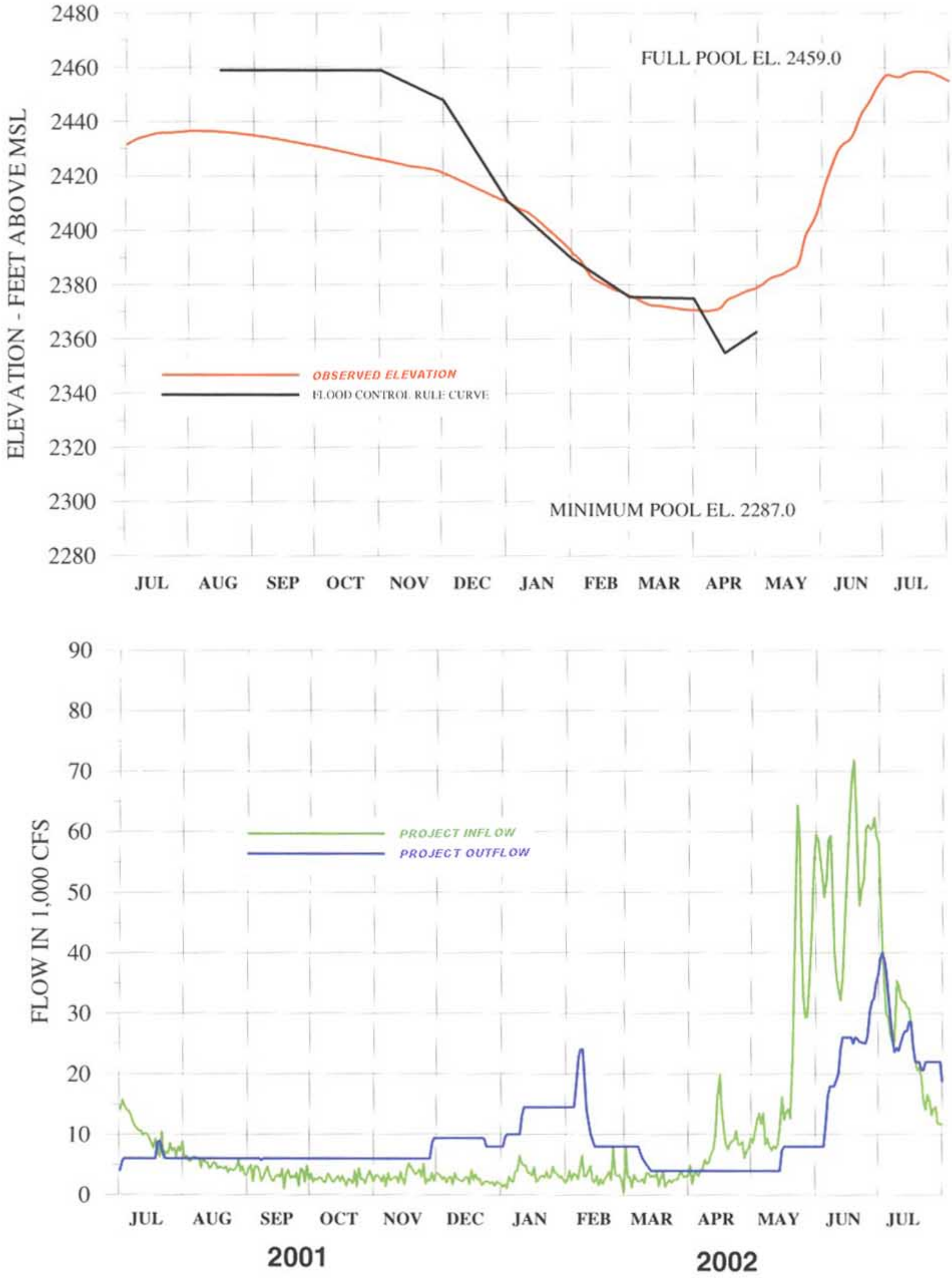
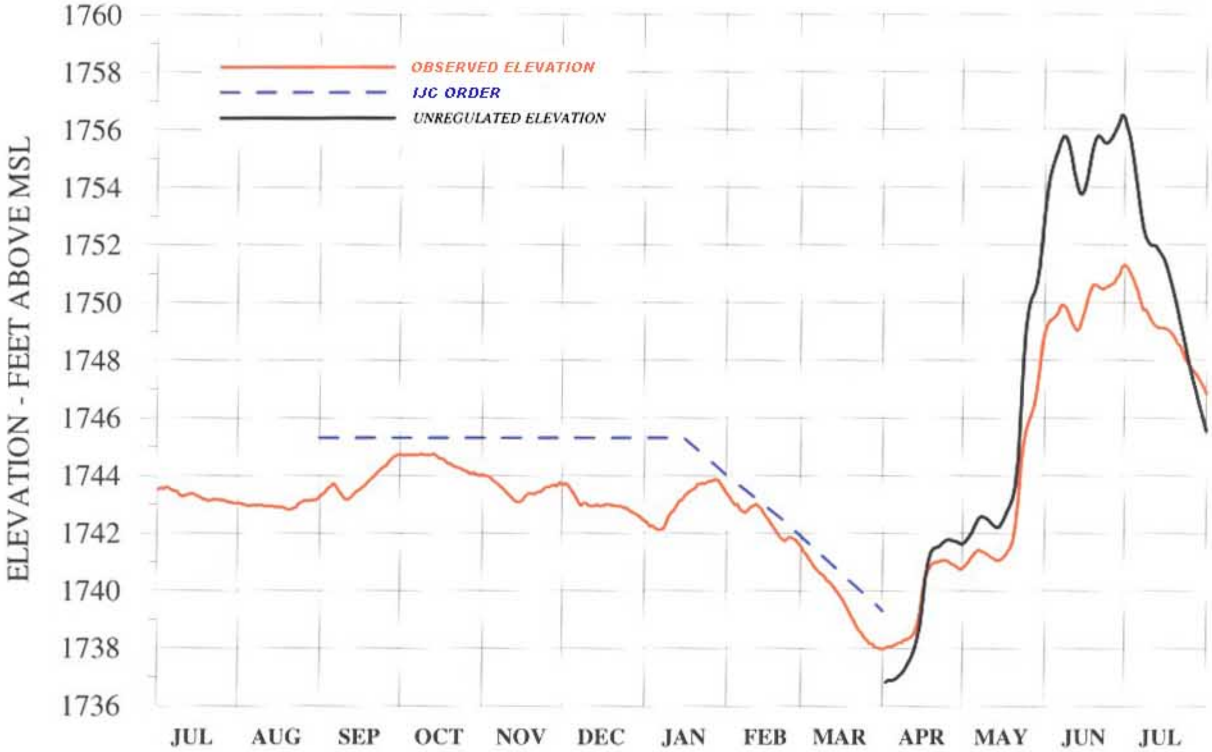


Chart 9: Regulation Of Kootenay Lake
1 July 2001 – 31 July 2002



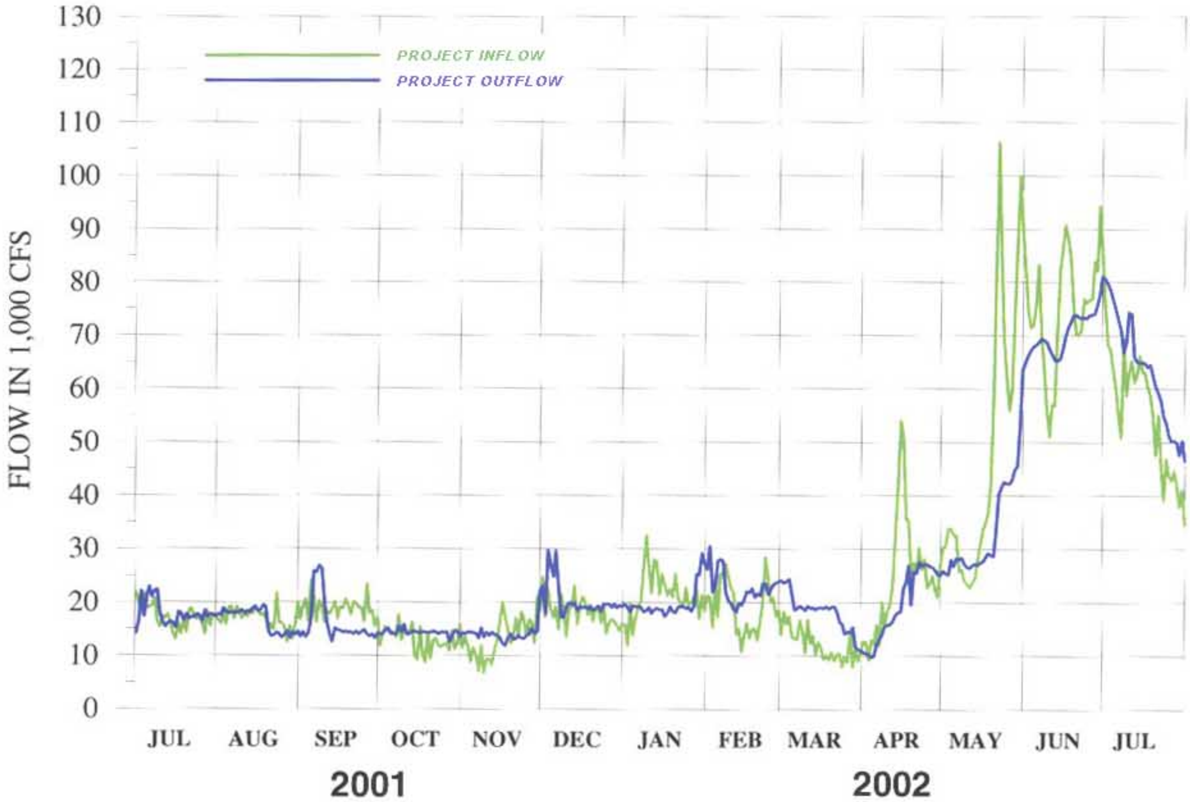


Chart 10: Columbia River At Birchbank
1 July 2001 – 31 July 2002

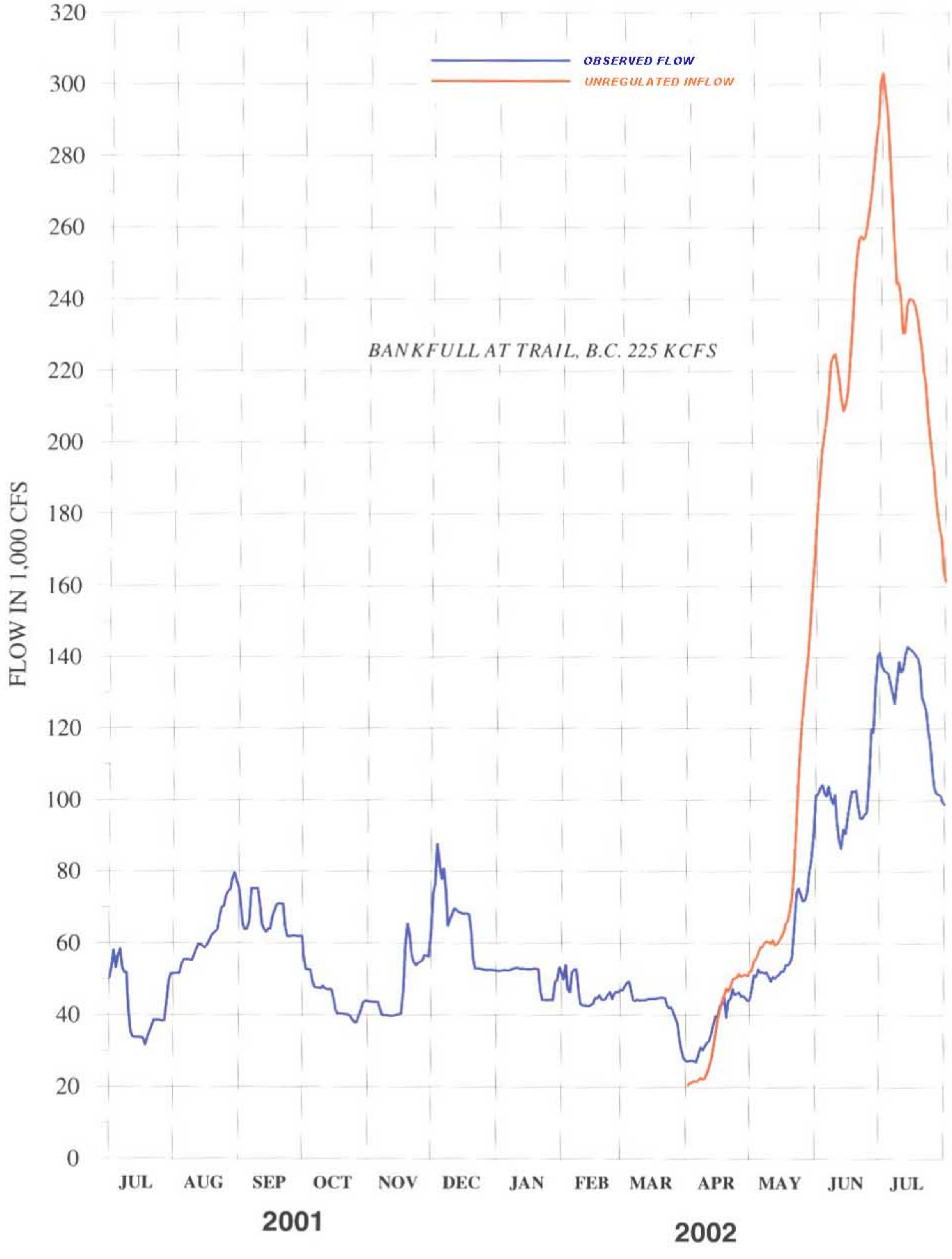
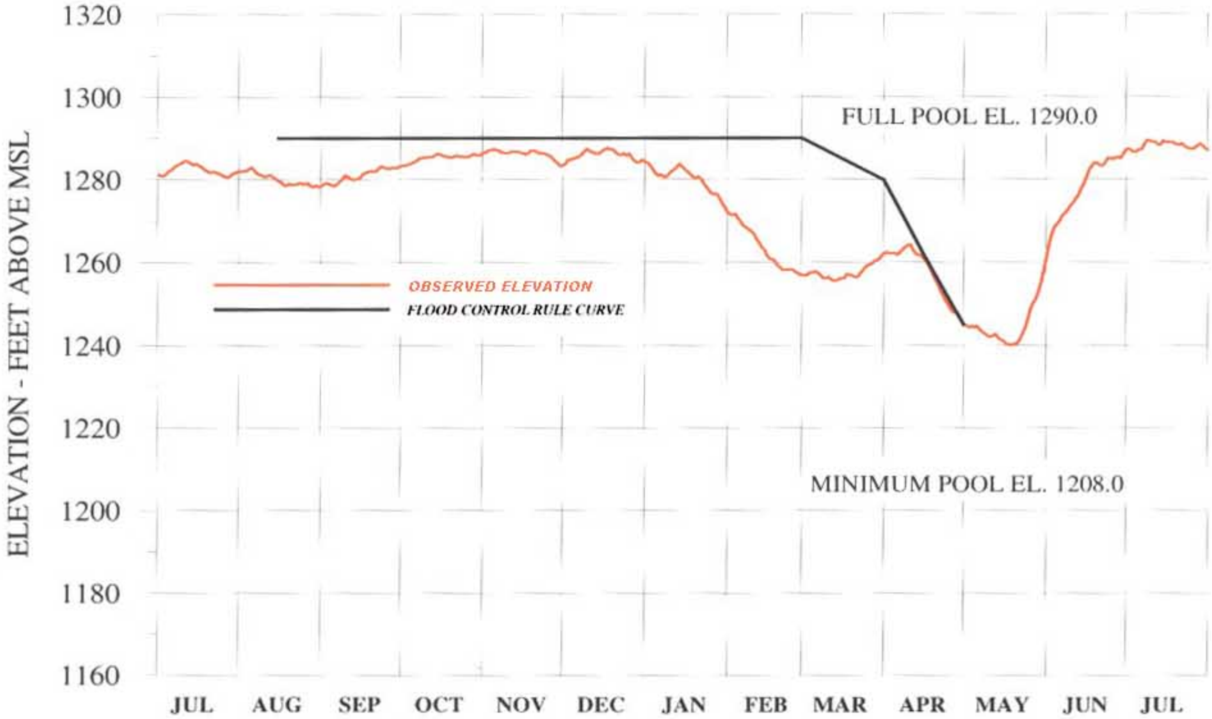


Chart 11: Regulation Of Grand Coulee
1 July 2001 – 31 July 2002



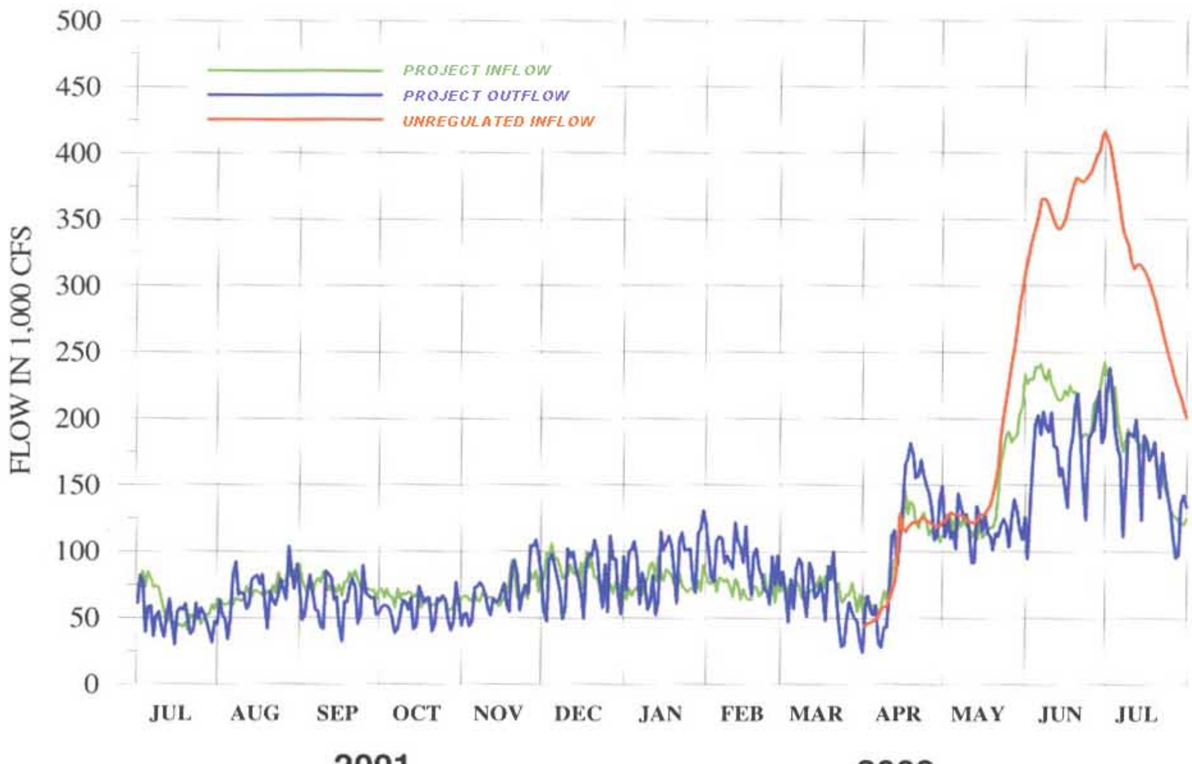


Chart 12: Columbia River At The Dalles (Summary Hydrograph) 1 July 2001 – 31 July 2002

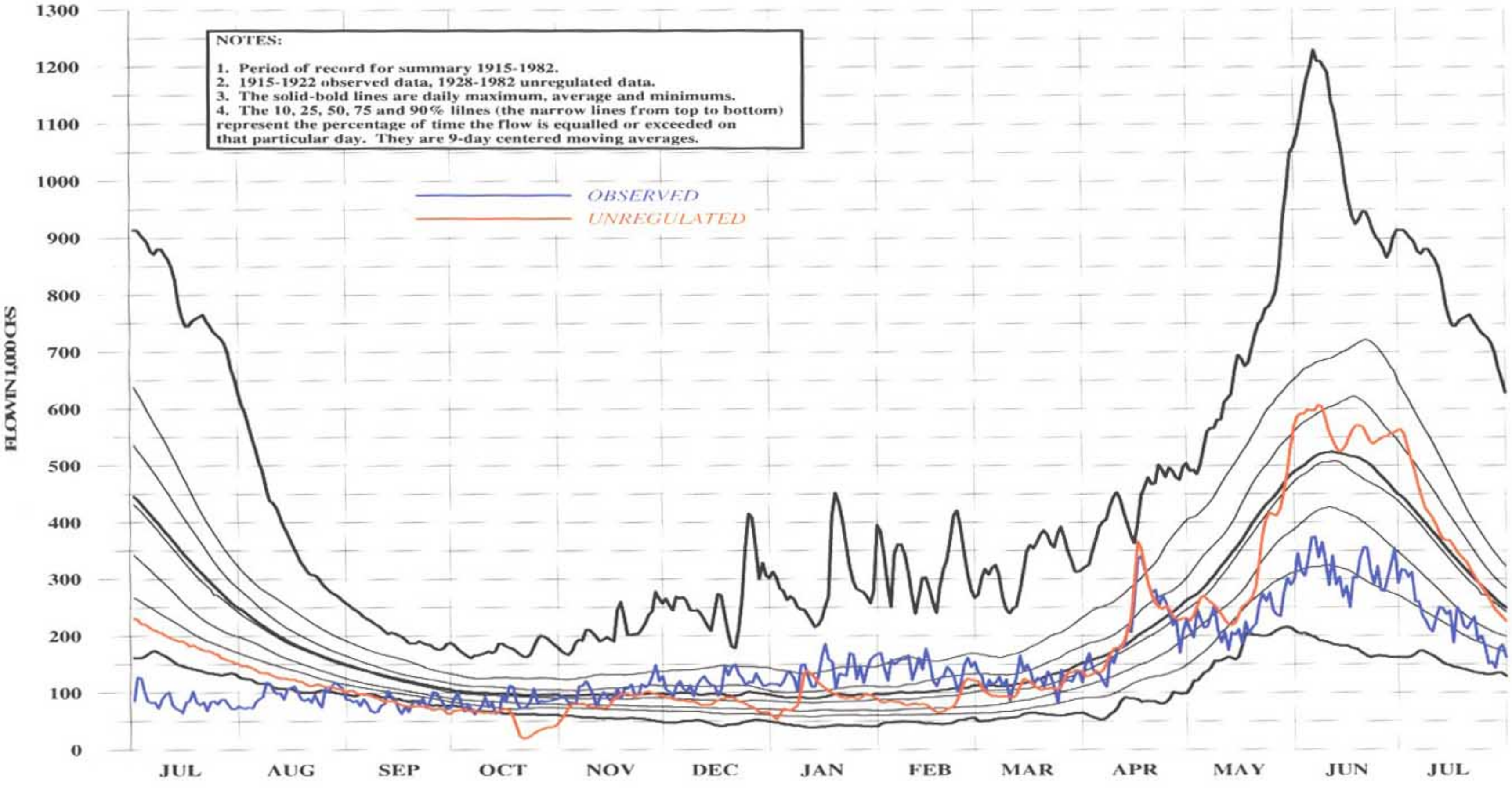


Chart 13: Columbia River At The Dalles (Re-Regulation Plot) 1 April 2001 – 31 July 2002

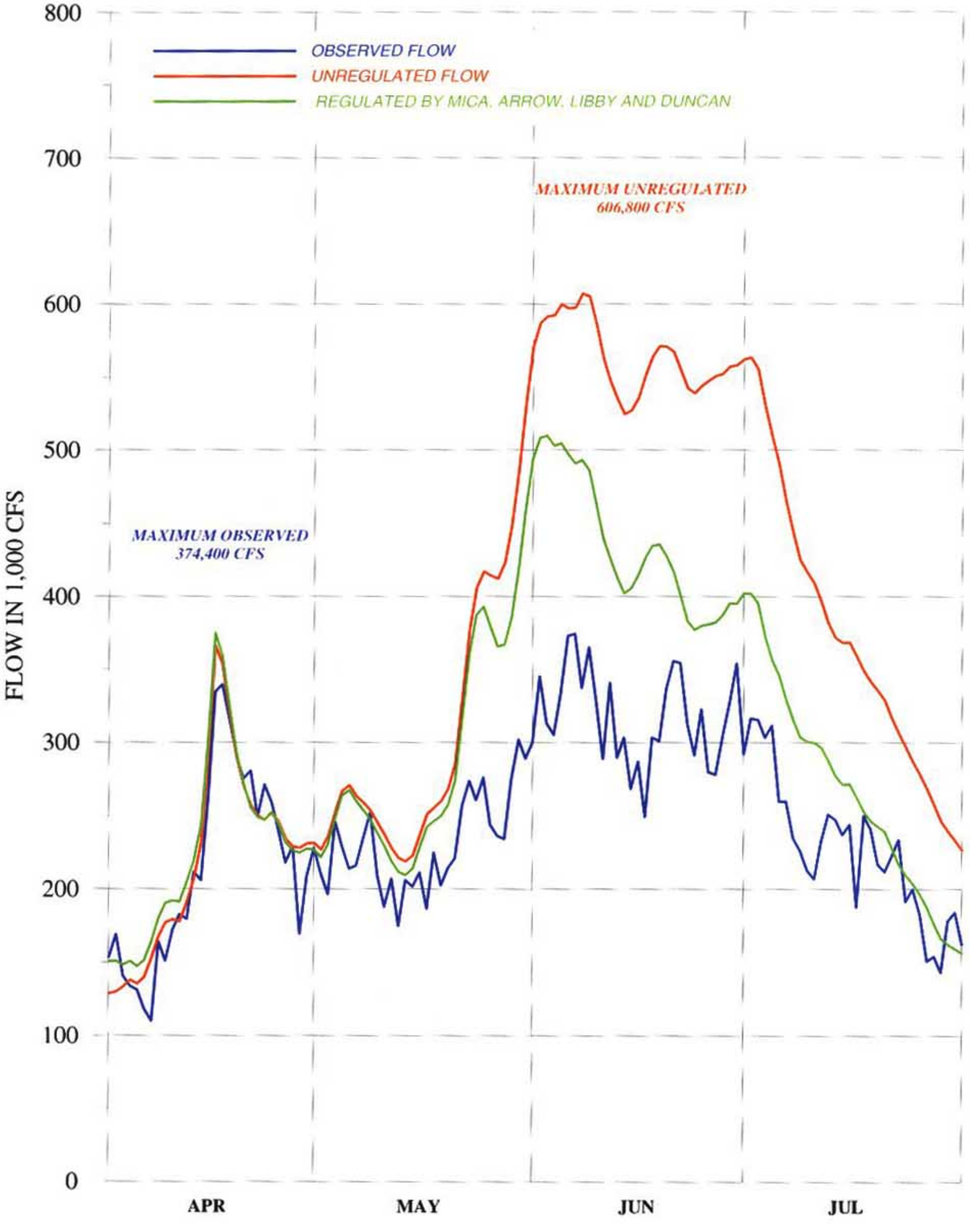


Chart 14: 2002 Relative Filling Arrow And Grand Coulee