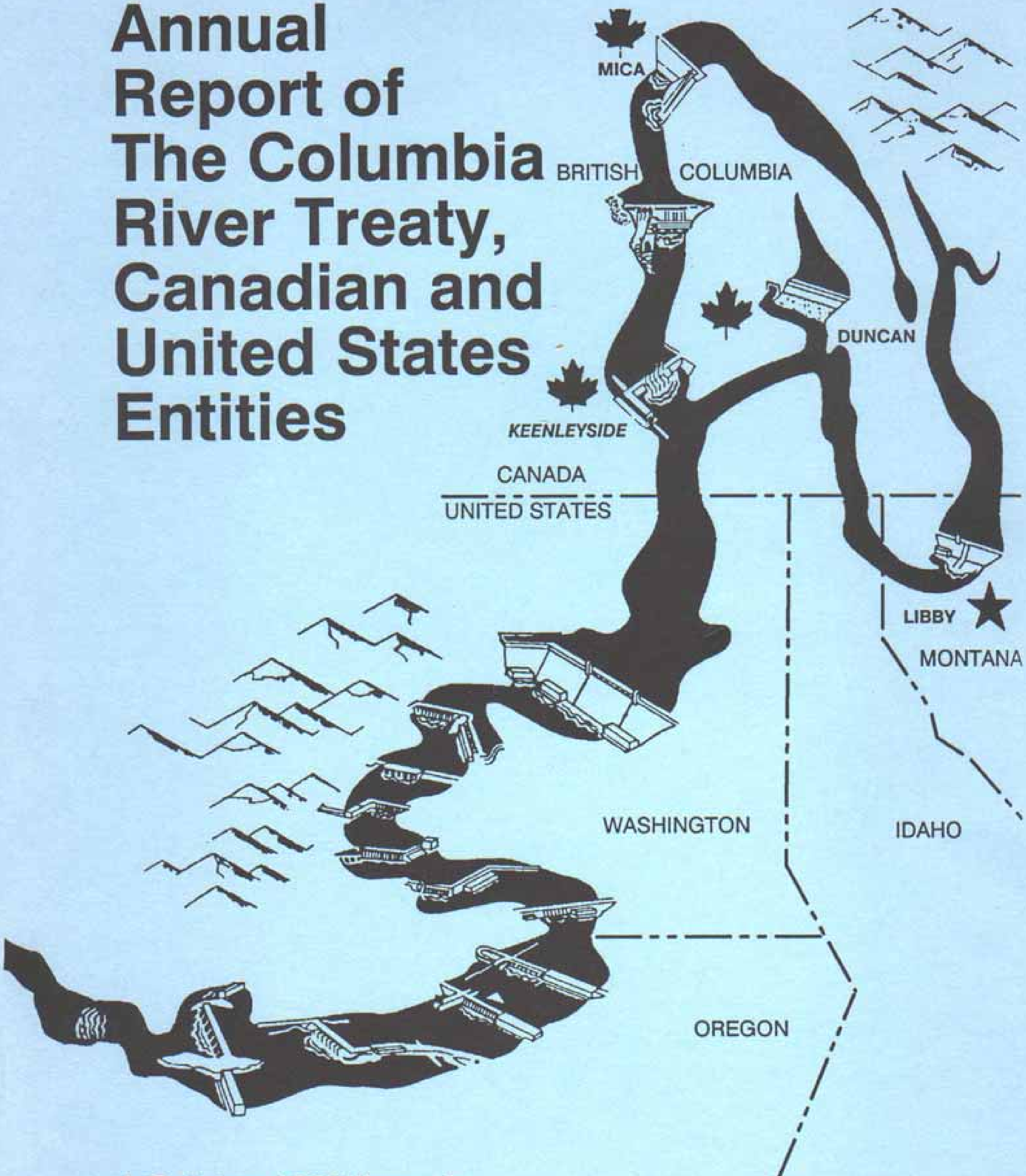
Annual Report of The Columbia River Treaty, Canadian and United States Entities



1 October 1990 through
30 September 1991

November 1991

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

FOR THE PERIOD

1 OCTOBER 1990 - 30 SEPTEMBER 1991

Executive Summary

Entity

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

- Detailed Operating Plan for Columbia River Treaty Storage, 1 August 1990 through 31 July 1991, dated September 1990.
- Entity Agreement on implementation of the Assured Operating Plan for Operating Year 1993-94, dated March 1991.
- Entity Agreements on the Assured Operating Plan, Determination of Downstream Power Benefits and Options for Development of the Detailed Operating Plan for Operating Years 1994-95 and 1995-96, dated March 1991.

System Operation

The coordinated system filled to 99.1 percent of capacity by 31 July 1990. As a result, first year firm energy load carrying capability (FELCC) was adopted for the 1990-91 operating year. During September and October the system proportionally drafted to meet FELCC. In November, unusually heavy precipitation triggered a streamflow rise, and the system returned to operating to energy content curves.

The 1 January water supply forecast for the Columbia River at The Dalles was 116.0 MAF, or 107 percent of average. As a result, the system began operating to volume-based energy content curves, permitting sizeable amounts of secondary energy to be sold. Precipitation and snowfall for the January-July period was slightly below normal, causing subsequent water supply forecasts to gradually decrease. The actual observed runoff was 107.1 MAF or 99 percent of average.

The peak daily average flow observed at The Dalles was 348,900 cfs. The lower Columbia River was regulated on a daily basis for flood control between 17 May and 18 June. The system storage content reached 99.6 percent of capacity on 31 July 1991. Generation at downstream projects in the United States, delivered under the Canadian Entitlement Exchange Agreement, was approximately 325 average megawatts at rates up to 1022 megawatts. All CSPE power was used to meet Pacific Northwest loads.

Treaty Project Operation

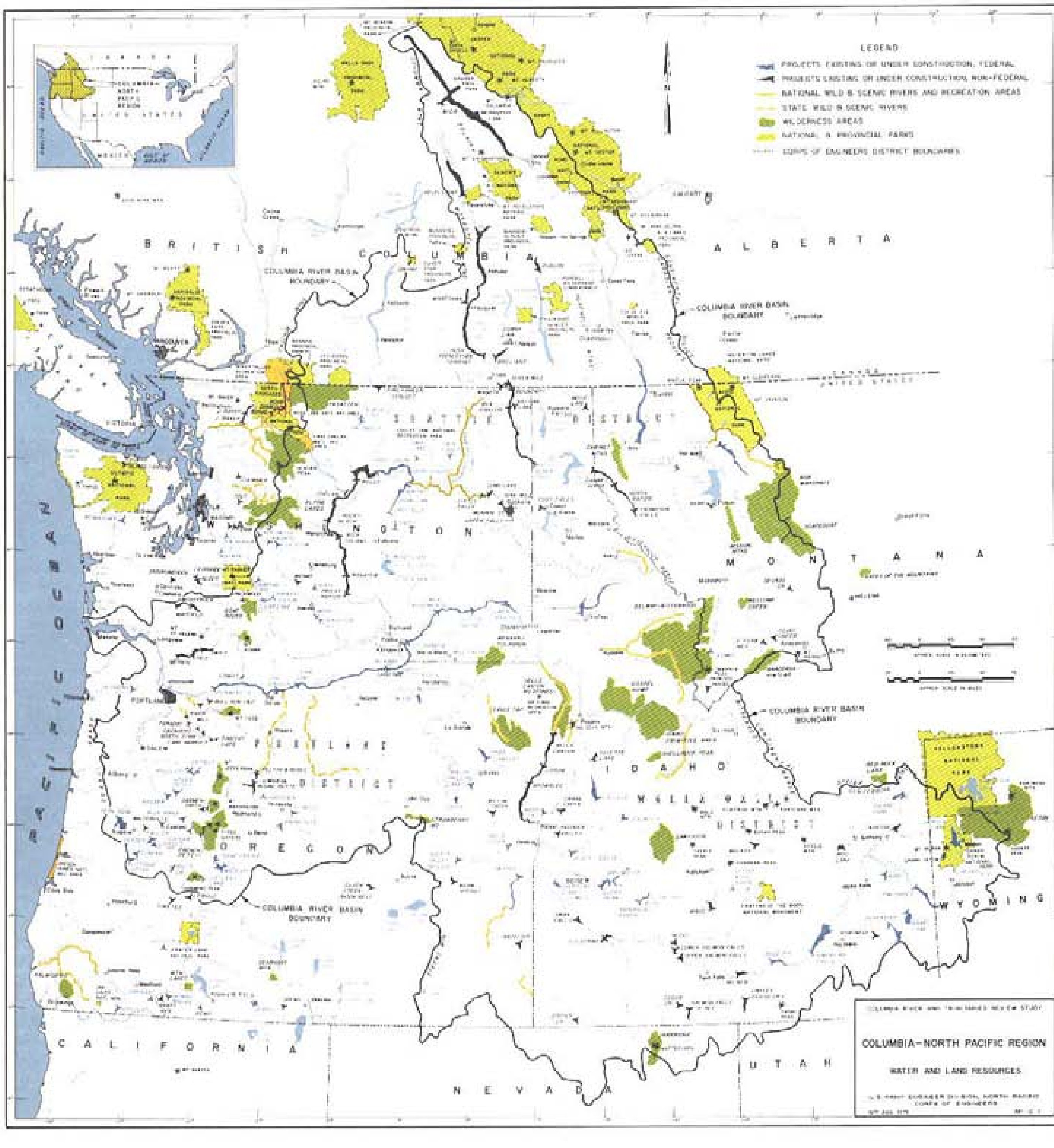
The Treaty projects were operated throughout the year in accordance with the 1990-91 Detailed Operating Plan and the Flood Control Operating Plan.

Mica treaty storage reached full content on 10 August 1990. The reservoir reached its lowest level, 2389.3 feet on 6 May 1991. Full treaty storage content was again reached on 3 August 1991. The maximum level for the operating year, 2475.85 feet, was reached on 10 August. This was Mica's highest level of record.

During the 1990 operating year, Arrow reached its maximum level of 1446.0 feet on 11 September 1990. The reservoir drafted throughout autumn and winter, reaching a minimum elevation of 1381.5 feet on 17 April. The maximum level in 1991 was elevation 1444.2 feet on 30 September.

Duncan reservoir completely filled during the 1990 operating year and remained full until 1 September. After some draft in early September, the reservoir refilled back to full pool by 15 October and remained full until 16 November. Because of the IJC-required draft of Kootenay Lake, which has precedent over Libby and Duncan flood control draft, and the reduced channel capacity of the Kootenay Lake outlet in February and March, it was only possible to draft about 85 percent of the total required spring flood control space at Libby and Duncan. On 31 March, total storage at these two reservoirs was about 560 kaf greater than flood control levels. Duncan reached its lowest level during the operating year, 1827.3 feet, on 3 April 1990. The reservoir reached full pool, elevation 1892.0 feet, on 1 August and remained full through September.

During the 1990 operating year, Libby reached full pool of 2459.0 feet on 26 July 1990. This was the first time the reservoir had reached full pool since 1987. The reservoir began being drawn down on 17 September, and by 31 December it had reached elevation 2400.9 feet. A minimum level of 2305.2 feet was reached on 2 April. The reservoir reached full pool, elevation 2459.0 feet on 27 July, and remained in its top foot through 31 August.



LEGEND
PROJECTS EXISTING OR UNDER CONSTRUCTION, FEDERAL
PROJECTS EXISTING OR UNDER CONSTRUCTION, NON-FEDERAL
NATIONAL WILD & SCENIC RIVERS AND RECREATION AREAS
STATE WILD & SCENIC RIVERS
WILDERNESS AREAS
NATIONAL & PROVINCIAL PARKS
CORPS OF ENGINEERS DISTRICT BOUNDARIES
BRITISH COLUMBIA
ALBERTA
WASHINGTON
MONTANA
OREGON
IDAHO
WYOMING
CALIFORNIA
NEVADA
UTAH
PACIFIC OCEAN
SEATTLE DISTRICT
PORTLAND DISTRICT
WALLA WALLA DISTRICT
COLUMBIA RIVER BASIN BOUNDARY
VANCOUVER
VICTORIA
PORTLAND
CANADA
UNITED STATES
YELLOWSTONE NATIONAL PARK
COLUMBIA-NORTH PACIFIC REGION
WATER AND LAND RESOURCES

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I Introduction

This annual Columbia River Treaty Entity Report is for the 1991 Water Year, 1 October 1990 through 30 September 1991. 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 1990 through 31 July 1991. The power and flood control effects downstream in Canada and the United States are described. This report is the twenty-fifth 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 United States of America were constructed under the provisions of the Columbia River Treaty of January 1961. Treaty storage in Canada is required to be operated for the purposes of flood control and increasing hydroelectric power generation in Canada and the United States of America. In 1964, the Canadian and the United States governments each designated an Entity to formulate and carry out the operating arrangements necessary to implement the Treaty. The Canadian Entity is the British Columbia Hydro and Power Authority (B.C. Hydro). The United States Entity is the Administrator of the Bonneville Power Administration (BPA) and the Division Engineer of the North Pacific Division, Army Corps of Engineers (ACE).

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

1. Canada is to provide 15.5 million acre-feet (maf) of usable storage. (This has been accomplished with 7.0 maf in Mica, 7.1 maf in Arrow and 1.4 maf in Duncan.)

2. For the purpose of computing downstream benefits the U.S. 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 additional power 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 expected 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. constructed Libby Dam with a reservoir that extends 42 miles into Canada and for which Canada made the land available.

7. Both Canada and the United States have the right to make diversions of water for consumptive uses and, in addition, after September 1984 Canada has the option of making for power purposes specific diversions of the Kootenay River into the headwaters of the Columbia River.

8. Differences arising under the Treaty which cannot be resolved by the two countries may be referred to either the International Joint Commission (IJC) or to arbitration by an appropriate tribunal.

9. The Treaty shall remain in force for at least 60 years from its date of ratification, 16 September 1964.

10. In the Canadian Entitlement Purchase Agreement of 13 August 1964, Canada sold its entitlement to downstream power benefits to the United States for 30-years beginning at Duncan on 1 April 1968, at Arrow on 1 April 1969, and at Mica on 1 April 1973.

11. Canada and the U.S. are each to appoint Entities to implement Treaty provisions and are to jointly appoint a Permanent Engineering Board (PEB) to review and report on operations under the Treaty.

II Treaty Organization

Entities

There was one meeting of the Columbia River Treaty Entities (including the Canadian Entity Representative and U.S. Coordinators) during the year on the morning of 29 November 1990 in Victoria, British Columbia. The members of the two Entities at the end of the period of this report were:

UNITED STATES ENTITY

Mr. Jack Robertson, Chairman
Acting Administrator, Bonneville Power Administration
Department of Energy
Portland, Oregon

Major General Ernest J. Harrell
Division Engineer
North Pacific Division
Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY

Mr. Bob Wyman, Chairman
Chairman, British Columbia Hydro and Power
Vancouver, B.C.

Mr. Robertson was appointed to succeed Mr. James J. Jura on 16 August 1991, and General Harrell succeeded General Patrick M. Stevens IV on 2 March 1991. Mr. Wyman succeeded Mr. Larry Bell effective 1 March 1991.

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

1. Plan and exchange information relating to facilities used to obtain the benefits contemplated by the Treaty.
2. Calculate and arrange for delivery of hydroelectric power to which Canada is entitled and the amounts payable to the U.S. for standby transmission services.
3. Operate a hydrometeorological system.
4. Assist and cooperate with the Permanent Engineering Board 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.

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

Entity Coordinators and Representative

The Entities have appointed members of their respective staffs to serve as coordinators or focal points on Treaty matters within their organizations.

The members are:

UNITED STATES ENTITY COORDINATORS

Edward W. Sienkiewicz, Coordinator
Senior Asst. Administrator for Power Management
Bonneville Power Administration
Portland, Oregon

Robert P. Flanagan, Coordinator
Director, Directorate of Planning and Engineering
Chief, Engineering Division
North Pacific Division
Army Corps of Engineers
Portland, Oregon

Pamela A. Kingsbury, Secretary
Energy Resource Specialist, Hydro Canadian Section
Division of Power Resources
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY REPRESENTATIVE

Douglas R. Forrest, Manager
British Columbia Hydro and Power
Vancouver, B.C.

Ms. Kingsbury was appointed to succeed Mr. Joseph Volpe, Jr., who passed away on 25 July 1990.

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	CANADIAN SECTION
Robert D. Griffin, BPA, Co-Chairman	Timothy J. Newton, BCH, Chairman
Nicholas A. Dodge, ACE, Co-Chairman	Ralph D. Legge, BCH
Russell L. George, ACE	Kenneth R. Spafford, BCH
John M. Hyde, BPA	Gary H. Young, BCH

There were seven meetings of the Operating Committee during the year. The dates, places and number of persons attending those meetings were:

Date	Location	Attendees
20 November 1990	Vancouver, B.C.	13
16 January 1991	Vancouver, Washington	14
13 March 1991	Vancouver, B.C.	15
14 May 1991	Vancouver, Wash	18
17 June 1991	Vancouver, B.C.	9
7 August 1991	Revelstoke, B.C.	15
26 September 1991	Portland, Oregon	18

The Operating Committee coordinated the operation of the Treaty storage in accordance with the current hydroelectric and flood control operating plans. This aspect of the Committee's work is described in following sections of this report which has been prepared by the Committee with the assistance of others. During the period covered by this report, the Operating Committee completed the 1990-91 Detailed Operating Plan (DOP), and completed the 1994-95 and 1995-96 Assured Operating Plans.

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 Treaty and otherwise assisting the Entities as needed. The Committee consists of four members as follows:

UNITED STATES SECTION	CANADIAN SECTION
Richard S. Watt, Acting Co-Chairman	William Chin, BCH, Chairman
Douglas D. Speers, ACE, Co-Chairman	Brian H. Fast, BCH, Member

Mr. Watt was appointed to temporarily succeed Ms. Carolyn Bohan on 30 June 1991. Mr. Fast was appointed 16 September 1991 to exceed John R. Gordon. There was one meeting of the Hydrometeorological Committee on 21 March in Portland. The committee reviewed the 1990 volume forecast results, hydromet station changes, developments on telemetry and changes in forecast procedures. In general, data was exchanged smoothly with no major problems.

Permanent Engineering Board

Provisions for the establishment of the Permanent Engineering Board (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
Herbert H. Kennon, Chairman, Washington, D.C. Ronald H. Wilkerson, Member Tulsa, Oklahoma	G.M. MacNabb, Chairman Ottawa, Ontario John Allen, Member Victoria, B.C.
John P. Elmore, Alternate Washington, D.C. Thomas L. Weaver, Alternate Golden, Colorado S.A. Zanganeh, Secretary Washington, D.C.	Don A. Kasianchuk, Alternate Victoria, B.C. E.M. Clark, Alternate & Secretary Vancouver, B.C.

In general, the duties and responsibilities of the PEB are to assemble records of flows of the Columbia River and the Kootenay River at the international boundary; report to both governments if there is deviation from the hydroelectric or flood control operating plans, and if appropriate, include recommendations for remedial action; 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; make 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, corrections 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 afternoon of 29 November 1990 in Victoria, British Columbia. A special joint meeting of the PEB and the Entities was held on 25 April 1991 in Seattle, Washington, to discuss the Entities position on the computation of capacity credit limits.

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
S.A. Zanganeh, Chairman Washington, D.C.	R.O. "Neil" Lyons, Chairman Vancouver, B.C.
Gary L. Fuqua, Member Portland, Oregon	Roger McLaughlin, Member Victoria, B.C.
Earl E. Eiker, Member Washington, D.C.	David M. McCauley, Member Victoria, B.C.
Larry Eilts, Member Golden, Colorado	
Stephen J. Wright, Alternate Member Washington, D.C.	
David Wingerd, Alternate Member Washington, D.C.	

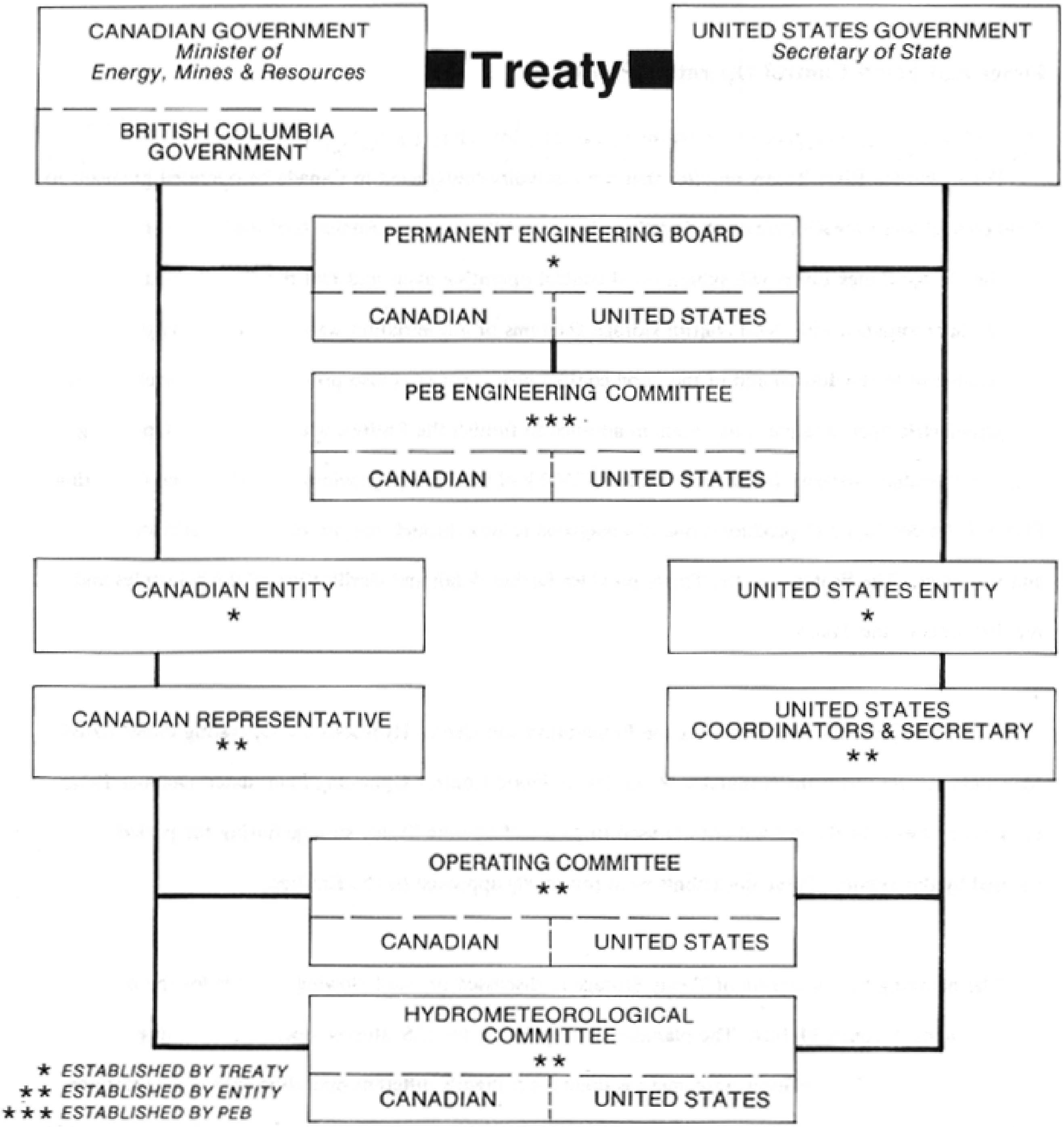
Mr. Eilts was appointed as a member of the US Section on 29 November 1990. Also on this same date, Mr. McCauley was appointed as alternate member of the Canadian Section. Mr. Wingerd was appointed as alternate member of the US Section on 21 January 1991.

International Joint Commission

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

The IJC has appointed local Boards of Control to insure compliance with IJC orders and to keep the IJC currently informed. There are four such boards west of the continental divide. These are the International Kootenay Lake Board of Control, the International Columbia River Board of Control, the International Osoyoos Lake Board of Control and the International Skagit River Board of Control. The Entities and their committees conducted their Treaty activities during the period of this report so that there was no known conflict with IJC orders or rules.

Columbia River Treaty Organization



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 and that the Canadian Entity will operate in accordance with flood control storage diagrams or any variation which the Entities agree will not be adverse to the desired aim of the flood control plan. Annex A also provides for the development of hydroelectric operating plans five years in advance to furnish the Entities with an Assured Operating Plan for Canadian storage. In addition, Article XIV.2.k of the Treaty provides that a Detailed Operating Plan may be developed to produce more advantageous results through the use of current estimates of loads and resources. 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 May 1983 together with the "Columbia River Treaty Flood Control Operating Plan" dated October 1972, establish and explain the general criteria used to plan and operate Treaty storage during the period covered by this report. These documents were previously approved by the Entities.

The planning and operation of Treaty Storage as discussed on the following pages is for the operating year, 1 August through 31 July. The planning and operating for U.S. storage operated according to the Pacific Northwest Coordination Agreement is done for a slightly different operating year, 1 July through 30 June. Therefore, most of the hydrographs and reservoir charts in this report are for a 13 month period, July 1990 through July 1991.

Assured Operating Plan

The Assured Operating Plan (AOP) dated November 1985 established Operating Rule Curves for Duncan, Arrow and Mica during the 1990-91 operating year. The Operating Rule Curves provided guidelines for draft and refill. They were derived from Critical Rule Curves, Assured Refill Curves, Upper Rule Curves, and Variable Refill Curves, consistent with flood control requirements, as described in the 1983 Principles and Procedures document. The Flood Control Storage Reservation Curves were established to conform to the Flood Control Operating Plan of 1972.

Determination of Downstream Power Benefits

For each operating year, the Determination of Downstream Power Benefits resulting from Canadian Treaty storage is made five years in advance in conjunction with the Assured Operating Plan. For operating years 1990-91 and 1991-92 the estimates of benefits resulting from operating plans designed to achieve optimum operation in both countries were less than that which would have prevailed from an optimum operation in the United States only. Therefore, in accordance with Sections 7 and 10 of the Canadian Entitlement Purchase Agreement, the Entities agreed that the United States was entitled to receive 2.7 average megawatts of energy during the period 1 August 1990 through 31 March 1991, and 3.5 average megawatts of energy during the period from 1 April through 31 July 1991. Suitable arrangements were made between the Bonneville Power Administration and B.C. Hydro for delivery of this energy. Computations indicated no loss or gain in dependable capacity during the 1990-91 operating year.

Detailed Operating Plan

During the period covered by this report, storage operations were implemented by the Operating Committee in accordance with the "Detailed Operating Plan for Columbia River Treaty Storage" (DOP), dated September 1990. The DOP established criteria for determining the Operating Rule Curves for use in actual operations. Except for minor changes at Arrow during the spring months, the DOP used the AOP critical rule curves for Canadian Projects. The Variable Refill Curves and flood control requirements subsequent to 1 January 1991 were determined on the basis of seasonal volume runoff forecasts during actual operation. Results of the Actual Energy Regulation were used to determine the triggering of high releases from Mica. The regulation of the Canadian storage was conducted by the Operating Committee on a weekly basis throughout the year.

Entity Agreements

During the period covered by this report, three agreements were officially approved by the Entities. The following tabulation indicates the date each of these were signed and gives a description of the agreement:

Date Agreement Signed by Entities	Description
19 November 1990	Detailed Operating Plan on Columbia River Treaty Storage, 1 August 1990 through 31 July 1991, dated September 1990.
1 March 1991	Entity Agreement on implementation of the Assured Operating Plan for Operating Year 1993-94.
1 March 1991	Entity Agreements on the Assured Operating Plan, Determination of Downstream Power Benefits and Options for Development of the Detailed Operating Plan for Operating Years 1994-95 and 1995-96.

Long Term Non-Treaty Storage Contract

In accordance with the 9 July 1990 Entity Agreement which 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 monitored the storage operations made under this Agreement throughout the last year to insure that they did not adversely impact operation of Treaty storage required by the Detailed Operating Plan.

IV Weather and Streamflow

Weather

Chart 1 is a geographical illustration of the seasonal precipitation in the Columbia River Basin, in percent of normal, for the period 1 October 1990 through 31 March 1991. Chart 2 shows an index of the accumulated snowpack in the Columbia Basin above The Dalles in percent of normal for the period 1 January through 31 May 1991. Indices of temperature and precipitation for the Columbia Basin above the Dalles for the winter and snowmelt seasons are shown on Charts 3 and 4, respectively. Chart 5 illustrates temperature and precipitation indices for the Columbia Basin in Canada during the snowmelt season. The following paragraphs describe significant weather events between 1 August 1990 and 30 September 1991.

The weather during water year 1991 was full of contrasts. Precipitation was above normal in the northern portion of the region and near normal over most of the remainder of the region. Only southwestern Idaho had significantly below normal precipitation. Temperatures were generally near normal except for a period near the end of December that was well below normal. These general statistics were made up of some significant events: near record snowpacks in the Okanogan basin, and several flood-producing storms in western Washington, Oregon, northern Idaho, and western Montana.

The weather in September, immediately preceding the water year, was dry and warm, protected by high pressure ridges or blocking low pressure systems. Precipitation in the Columbia Basin above The Dalles was only 21 percent of normal and temperatures were 3°-9°F above normal, resulting in reduced soil moisture and streamflow. On 5 October the jet stream moved southward over Oregon as a weak front moved through western Washington, bringing heavy showers. A transient pressure ridge built but soon collapsed as a strong westerly flow brought more unstable fronts through the northern portion of the

Pacific Northwest. These storms were frequent and some were very heavy locally west of the Cascades. Spokane reported the wettest October on record and several sub-basins reported well over 200 percent of their normal monthly precipitation. The October precipitation was 172 percent of normal for the Columbia basin above The Dalles.

On two separate occasions during November jet streams arching from Hawaii to the Washington coast developed, bringing warm, moist tropical air into the Pacific Northwest. This produced heavy rains, high river discharges, and floods along the British Columbia border from the coast to the Continental Divide. November precipitation was 146 percent of average above The Dalles.

During the first 18 days of December temperatures and precipitation were normal with five storms passing through the northern half of the basin. Then a weak Arctic trough moved on-shore and was strengthened by the building of a strong high pressure ridge immediately off the coast. This provided a short over-water trajectory for cold Arctic air, moving southward into the Pacific Northwest. Even with the protection of the strong ridge, weak weather disturbances moving through the area produced snow, even in the low lands of western Washington and Oregon. This pattern lasted until 8 January with only two brief breaks: on 28 December and 2 January when weak frontal systems crossed the basin. By 9 January the ridge had collapsed and temperatures moderated to near normal. The ridge then rebuilt, to a lesser intensity and with normal temperatures, but strong enough to eliminate most precipitation until its collapse at the end of the month. January precipitation was 69 percent of normal in the Columbia basin above Grand Coulee.

February saw a change in the jet stream to a more southerly course, bringing warmer weather and typical winter storms into western Washington. Except for the coastal areas of Washington and northern Oregon and British Columbia, the remainder of the Northwest received much less than normal precipitation. During March the storm track moved northward, the mean daily temperatures fell to normal, and the rate of precipitation increased.

April and May saw a continuation of these weather patterns with slightly greater than normal precipitation and mean daily temperatures gradually increasing, although not as rapidly as normal. During these two months the precipitation for the Columbia basin above The Dalles was 124 and 153 percent of average, respectively. Despite these heavy rains the snowmelt progressed at a steady pace without any large surges in streamflow.

June remained cool, producing a very controlled snowmelt with no high peak discharges. Several low pressure systems from Alaska moved through the region in July bringing fronts that triggered widely scattered showers and unseasonable cool temperatures. A few hot dry spells in August completed the snowmelt in British Columbia. August ended with cool weather and light rains during the last week of the month.

The final monthly precipitation indices for the Columbia Basin above The Dalles are shown below for the 1991 water year. These indices are based on 60 stations and are computed at the end of each month after all the data are collected. Also shown in the table are the monthly indices as a percent of the 25-year average (1961-1985).

WY 91 INDICES

MONTH	PRECIPITATION		MONTH	PRECIPITATION	
	(in.)	(%)		(in.)	(%)
OCT 90	3.01	172	APR 91	2.05	124
NOV 90	4.05	146	MAY 91	2.75	153
DEC 90	2.78	83	JUN 91	2.19	14
JAN 91	1.98	64	JUL 91	0.80	76
FEB 91	1.64	75	AUG 91	1.58	78
MAR 91	2.28	118	SEP 91	0.67	45
			WATER YEAR	25.22	104

Streamflow

The observed inflow and outflow hydrographs for the Treaty reservoirs for the period 1 July 1990 through 31 July 1991 are shown on Charts 6 through 9. Observed flows 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 10, 11, 12, and 13, respectively. Chart 14 is a hydrograph of observed and two unregulated flows at The Dalles during the April through July 1991 period including a plot of flows occurring if regulated only by the Treaty reservoirs.

Streamflows in the basin above The Dalles were near normal for the composite operating year, with November, February, July, and August exceeding the norm. The October through September runoff for The Dalles was 101 percent of the 1961-85 average. The peak regulated discharge for the Columbia River at The Dalles was 348,000 cfs on 26 May 1991. The 1990-91 monthly natural streamflows and their percent of the 1961-85 average monthly flows are shown in the following table for the Columbia River at Grand Coulee and at The Dalles. These flows have been corrected for storage in lakes and reservoirs to exclude the effects of regulation.

		COLUMBIA RIVER AT GRAND COULEE IN CFS		COLUMBIA RIVER AT THE DALLES IN CFS	
TIME PERIOD		NATURAL FLOW	PERCENT OF AVERAGE	NATURAL FLOW	PERCENT OF AVERAGE
AUG	90	108,800	100	141,340	99
SEP	90	52,750	78	78,680	79
OCT	90	43,390	87	78,410	90
NOV	90	85,050	181	114,650	128
DEC	90	50,620	118	100,040	102
JAN	91	36,230	87	92,800	91
FEB	91	66,190	133	133,670	111
MAR	91	53,800	91	115,840	78
APR	91	126,830	113	205,360	94
MAY	91	294,140	110	431,060	100
JUN	91	336,291	99	474,620	92
JUL	91	258,850	129	328,610	121
YEAR		126,390	110	193,340	101

Seasonal Runoff Forecasts and Volumes

Observed 1991 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 1000 Acre-Feet	Percent of 1961-85 Average
Libby Reservoir Inflow	8536	131
Duncan Reservoir Inflow	2402	117
Mica Reservoir Inflow	13568	117
Arrow Reservoir Inflow	26180	112
Columbia River at Birchbank	48555	118
Grand Coulee Reservoir Inflow	69603	111
Snake River at Lower Granite Dam	15733	65
Columbia River at The Dalles	97028	101

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 1991 as usual 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 volume inflow forecasts for Mica, Arrow, Duncan, and Libby projects and for unregulated runoff for the Columbia River at The Dalles. Also shown in Table 1 are the actual volumes for these five locations. The forecasts for Mica, Arrow and Duncan inflow were prepared by B.C. Hydro and those for the lower Columbia River and Libby inflows were prepared by the United States Columbia River Forecasting Service. The 1 April 1991 forecast of January through July runoff for the Columbia River above The Dalles was 106.0 MAF and the actual observed runoff was 107.1 MAF.

The following tabulation summarizes monthly forecasts since 1970 of the January through July runoff for the Columbia River above The Dalles compared to the actual runoff measured in millions of acre-feet (MAF):

Year	Jan	Feb	Mar	Apr	May	June	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	84.7	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

V Reservoir Operation

General

The 1991 operating year was characterized by unusually wet autumn conditions, near normal winter weather and a cool spring, which delayed the snowmelt runoff. At The Dalles, the observed January-July runoff was 99 percent of average, one percent higher than the April forecast, but eight percent lower than the January forecast. This runoff volume was the highest since 1986. July natural streamflows at The Dalles were 121 percent of average, reflecting delayed runoff of the upper Columbia snowpack due to the unusually cool spring.

The operating year began with the coordinated reservoir system officially filling to 99.1 percent of capacity on 31 July 1990. As a result, first year firm energy load carrying capability (FELCC) was adopted for the 1990-91 operating year.

The system began the year operating to energy content curves (ECC) in August, and some secondary energy was sold. During September and October, the system operated in accordance with proportional draft requirements, with draft levels between first- and second-year critical rule curves. In November, unusually heavy precipitation triggered a rise in streamflows throughout much of the Columbia basin, and the reservoir system returned to operating to ECCs.

The 1 January water supply forecast was 116.0 maf for the January-July period, or 107 percent of the 1961-85 average. Subsequent forecasts through April reflected a decreasing trend, with the April forecast 98 percent of average.

The unusually cool spring resulted in a protracted runoff of the unusually high snowpack, with April through June natural flows at The Dalles near-to-below average, and July and August flows well above average. Despite the delayed runoff, mid-Columbia streamflows were high enough throughout the entire spring water budget period that no mid-Columbia water budget releases were necessary to enhance flows for downstream migration of juvenile anadromous fish. During the 15 April - 15 June water budget period, the Priest Rapids outflow averaged 200,000 cfs and was below 140,000 cfs on only one day. Flows at The Dalles during this period averaged 282,000 cfs and were above 200,000 cfs every day during the period.

Over the weekend of 17 May, a combination of snowmelt and heavy rainfall triggered a rapid rise in streamflows throughout the Columbia/Snake basins, prompting daily flood control regulation of the Columbia system to begin. The river was regulated on a daily basis for flood control between 17 May and 18 June. The year's observed peak flow at The Dalles was 348,000 cfs on 26 May. Last year's peak was 372,000 cfs. The system reached 99.6 percent of its full capacity on 31 July 1991, allowing first-year FELCC to be adopted for the 1991-92 operating year for the second successive year.

Mica Reservoir

As shown in Chart 6, Mica reservoir was at elevation 2470.9 feet, approximately four feet below its full pool elevation 2475 feet, on 31 July 1990. The Treaty storage was filled to its full storage content ten days later on 10 August. With above average inflow in August, the reservoir continued filling to 2474.1 feet by 23 August.

During September, Mica was lowered by approximately four feet to elevation 2470.2 feet by 30 September. On 1 October, the Mica Treaty storage release was increased to above inflow, to begin drafting two feet of Treaty storage for flood control space per the Detailed Operating Plan. The Treaty storage release, together with releases from non-Treaty storage at Mica, lowered the reservoir to 2464.7

feet by 31 October. Between 12 November and 3 December, above average inflow resulted in Mica remaining near elevation 2463 feet.

On 1 December, pursuant to the new Non-Treaty Storage Agreement (BPA Contract No. DE-MS79-90BP92754), 2.5 maf of BC Hydro's storage at Mica was re-classified as non-Treaty storage, divided equally and transferred into BCH's and the United State's Active storage accounts.

As system power requirements increased, the Mica outflow was increased to full powerhouse capacity during December. Consequently, the reservoir was drawn down to elevation 2450.9 feet by 31 December, slightly below its Operating Rule Curve after adjusting for non-Treaty storage and an imbalance between Mica and Arrow Treaty storage content.

During January and February, the project outflow at Mica was generally maintained near full powerhouse capacity of 40,000 cfs. By 28 February, the reservoir was drawn down to elevation 2417.2 feet. The project continued drafting in March. During April, the Treaty storage release was increased above its normal Detailed Operating Plan schedule of 15,000 cfs (for 1 - 15 April period) and 10,000 cfs (for 16 - 30 April period), to compensate for an "under-draft" of Mica Treaty storage in March due to an error in computing the Mica operating rule curve. This adjustment allowed the correct amount of Treaty storage to be drafted from Mica by the end of April.

On 6 May, Mica reached its lowest level for 1991 at elevation 2389.3 feet. Mica began filling on 7 May. During the refill period, the project outflow was reduced, at times to as low as zero discharge, to allow maximum storage into Treaty and non-Treaty storage accounts. Inflow into the reservoir was below average in June due to cool temperatures. As the weather became warmer in July, the inflow increased to well above average, peaking at 89,900 cfs on 3 July.

The reservoir filled quickly in May and June, and reached elevation 2445.1 feet by 30 June. Beginning 7 July, the discharge at Mica was progressively increased, reaching full powerhouse capacity of 40,000 cfs on 20 July, to reduce the rate of filling. The reservoir reached elevation 2472.8 feet on 31 July. Treaty storage reached its full storage content three days later, on 3 August. Mica reached full pool of elevation 2475 feet on 8 August. The project began spilling on 9 August as the reservoir inflow remained well above average. On 10 August, high temperatures and heavy local precipitation increased the inflow to the peak for the year, 98,360 cfs. The reservoir was surcharged to elevation 2475.85 feet and the total project outflow was increased to as high as 100,500 cfs for part of the day. This elevation was Mica reservoir's highest level of record. Inflow receded after the peak, but remained above the powerhouse capacity through 24 August, and the project stopped spilling. Another rainstorm on 1 September triggered a rise in reservoir inflow to a peak of 52,830 cfs, but spill was not necessary as inflows quickly receded.

Revelstoke Reservoir

During this past operating year, the Revelstoke project was basically operated as a run-of-the-river plant, maintaining the reservoir level within two feet of its normal full pool elevation of 1880 feet.

In June, the reservoir was drawdown approximately five feet below full pool prior to the summer runoff. The inflow in early August was unusually high and the reservoir refilled to full pool and began spilling on 9 August. In order to discharge the high runoff on 10 August, the project discharge was increased to a maximum of 114,500 cfs for part of the day. Spilling at Revelstoke was gradually reduced as the inflow into the reservoir receded, and the project stopped spilling on 21 August.

Arrow Reservoir

As shown in Chart 7, Arrow reservoir was filled to elevation 1443.3 feet by 31 July. The reservoir continued filling and reached full pool of elevation 1444.0 feet on 5 August. During the period 6-21 August, the Arrow discharge varied between 53,000 cfs and 70,000 cfs, maintaining the reservoir level at about 1444 feet. On 22 August, the project outflow was reduced below inflow to begin filling into Arrow non-Treaty storage with water that was surplus to system load requirements at the time. This caused the reservoir to surcharge above 1444 feet to elevation 1446 feet by 11 September. This non-Treaty storage was released from Arrow by 30 November.

Drafting of Arrow Treaty storage began on 29 September. By 31 October, about two feet of Treaty storage was released from the reservoir, meeting its flood control drawdown requirement for October. Arrow continued drafting in November and December to meet downstream power requirements. The reservoir reached elevation 1429.2 feet, or approximately three feet higher than the Operating Rule Curve after adjusting a storage imbalance between Mica and Arrow reservoirs, on 31 December. During this period, the project outflow varied between 20,000 cfs and 70,000 cfs.

Snow accumulation was above normal for the upper Columbia River basin during the winter months. This lowered Arrow's Operating Rule Curve to allow maximum drawdown prior to the freshet. The heavy draft, which began in late December, continued in January and February with the project combined Treaty and non-Treaty storage releases increased to as high as 104,200 cfs on 30 January. From 23 February until 6 March, the reservoir filled temporarily by approximately four feet to elevation 1403.9 feet. The project resumed drafting on 7 March. Beginning 23 March and continuing until mid-April, Arrow was on free flow, discharging its maximum possible outflow. On 17 April, Arrow reservoir reached its lowest level for 1991 at elevation 1381.5 feet.

During the period 26-28 April, the Arrow outflow was reduced to the minimum discharge of 5,000 cfs for several hours each day to accommodate underwater inspection of the guidewall cables and the upstream blanket at the dam. As the tailwater level dropped, about 89 nests of trout eggs (redds) were discovered at gravel bars near the City of Castlegar where Pass Creek discharges into the Columbia River. After the dam inspection, it was agreed to maintain a sufficient Arrow discharge to protect the eggs so long as it did not jeopardize reservoir refill. With well above average flows from the Kootenay River resulting in a backwater effect in the spawning area (which was near the confluence of the Columbia and Kootenay) it was possible to gradually reduce the Arrow discharge in June to accelerate refilling of the reservoir.

On 28 June, the project outflow was further reduced to 10,000 cfs to further accelerate refill. With well above average runoff in July, Arrow quickly filled to elevation 1441.9 feet by 3 August. Including the surcharge storage at Mica the Treaty storage account at Arrow was considered refilled to its full content on that day.

On 3 and 4 August, the project outflow was maintained at 60,000 cfs instead of being increased to pass inflow, to help maintain low flows for the unloading of a nuclear reactor in the mid-Columbia River. On 10 August, inflow to Arrow reservoir increased significantly due to spilling at Mica and Revelstoke Reservoirs. The discharge at Arrow was increased up to 115,000 cfs on 13 August.

On 14 August, additional storage space (two feet between elevations 1444 feet and 1446 feet) were made available for non-Treaty storage at the Arrow project. The project outflow was reduced to below inflow to begin filling into these non-Treaty storage accounts. Both accounts were filled by 25 August. The reservoir reached its maximum level for 1991, elevation 1444.2 feet, on 30 September.

Duncan Reservoir

As shown in Chart 8, Duncan reservoir reached full pool of elevation 1892 feet on 31 July. During August, the project discharged inflow to maintain the reservoir at full pool. Between 1 and 16 September, the discharge was maintained at 6,000 cfs, drafting the reservoir approximately six feet. Beginning 22 September, the outflow was reduced to minimum discharge of 100 cfs to prevent spilling at power plants on the Kootenay River. With near average inflow into the Duncan, the reservoir slowly refilled to full pool by 15 October. Duncan then discharged inflow until 16 November.

Duncan began drafting its storage when the project outflow was increased to 6,000 cfs on 17 November and then further increased to 8,000 cfs on 2 December. By 31 December, the reservoir was drawn down approximately 24 feet to elevation 1868 feet, which is essentially equal to the 31 December flood control requirement.

During January the outflow averaged 8,500 cfs and by the 31st, the reservoir reached elevation 1838.9 feet. During February and March, due to Grohman Narrows limiting the discharge capability from Kootenay Lake, the Duncan discharge was reduced to an average of 2,000 cfs to prevent Kootenay Lake from exceeding its IJC curve. Inflow into Duncan was sufficiently low that the reservoir continued drafting during this period. On 3 April, Duncan reservoir reached elevation 1827.3 feet, its lowest level for the current operating year, but 20 feet above the flood control requirement of 1807.7 feet.

Since Duncan reservoir was at an unusually high level prior to the spring snowmelt period, and above average runoff was expected, refill of the reservoir was delayed past April until near the end of May. Prior to refill, the project outflow was adjusted to equal inflow. As a result, the reservoir level remained at about 1830 feet during April and May. On 25 May, the reservoir began filling when the project discharge was reduced to 7,000 cfs. It was further reduced to 1,000 cfs on 8 June. The snowmelt runoff was below normal in June but increased significantly in July, with the inflow peaking at 18,200 cfs on 3 July. The outflow remained at 1,000 cfs until 6 July when it began being increased to slow the refill of the final 20 feet of reservoir space. The reservoir reached full pool of 1892 feet on 1 August and the project outflow was then adjusted to match the inflow.

On 10 August, high temperature and heavy thunderstorm activity increased the daily average inflow to 15,920 cfs and the reservoir was surcharged to elevation 1892.7 feet. The inflow soon receded and the reservoir was drawn back down to near full pool by 13 August.

Libby Reservoir

As shown in Chart 9, Libby completely refilled following the 1990 runoff, with Lake Koocanusa reaching full pool on 26 July 1990. This was the first time the reservoir had reached full pool since 1987. The reservoir remained full through Labor Day and did not begin drafting until 17 September. The draft was initiated by BPA's desire to import holding interchange energy, which required that Libby be drafted to its Energy Content Curve.

Lake Koocanusa was drafted further through October and into early November, reaching elevation 2428.2 feet on 8 November. Outflows averaged almost 20,000 cfs during this period, and some provisional draft occurred. For the remainder of November, Libby discharged minimum flow as the Columbia system returned to operating to ECC following a series of fall storms. In December, the discharge was increased to full powerhouse capacity and additional provisional draft occurred. By the end of the month the reservoir reached 2400.9 feet, nine feet below ECC. Inflows during the October-December period were 140 percent of average.

In January, water supply forecasts for the upper Columbia drainages were well above average. Libby's forecast was 130 percent, indicating a complete winter draft of the reservoir would likely be necessary for flood control. Throughout January, Libby discharged at full powerhouse capacity, averaging 24,500 cfs, and drafted to 2358.4 feet, two tenths of a foot above the 31 January flood control point. The February water supply forecast continued at 130 percent and both snowpack and observed streamflows remained above normal. Early in February, it was necessary to begin reducing the Libby outflow to keep Kootenay Lake from exceeding its IJC rule curve. Throughout the rest of February and all of March, Libby was restricted to control the Kootenay Lake inflow per the IJC criteria. By late March, Libby's outflow had gradually been reduced to 6,000 cfs, and by 2 April, the reservoir reached elevation 2305.2 feet, its lowest point of the year, but 18.2 feet above the 31 March flood control point of 2287.0 feet (minimum pool).

Libby passed inflow throughout most of April as the reservoir's refill probability exceeded the 95 percent level at which refill is usually initiated. Observed inflows and snowpack continued to be above normal and the April water supply forecast remained above normal at 126 percent. Later in the month, inflows began to rise and the reservoir began gradually refilling. In early May, outflow was reduced to 4,000 cfs to refill the reservoir to 2335.0 feet by mid-month to improve lake access for recreation. In mid-May, following heavy rainfall and snowmelt which triggered runoff in the Kootenai River, outflows were reduced to control water levels flows at Bonners Ferry, where some lowland crop flooding occurred. During this event, inflows to Libby peaked for the runoff season at 65,500 cfs. During the second half of May and into early June, outflows were regulated to provide flows near 20 to 30 kcfs downstream near Leonia for an Idaho Fish and Game sturgeon spawning study. By mid-June, following the releases for sturgeon, outflows were reduced to near 6,000 cfs to increase the refill rate. By the end of the month the reservoir refilled to within 22 feet of full. In early July the outflows were increased to near 25,000 cfs to slow the final refill and avoid spill. On 27 July the project reached full pool and was operated in its top half foot, 2458.5 to 2459.0 feet, through August. During August and September outflows of 14,000 cfs were provided for downstream data collection by the Montana Department of Fish, Wildlife and Parks for fish habitat modelling.

The January-July observed runoff was 8614 kaf, 133 percent of average. This runoff volume was the highest since 1974 and the 6th highest in the 1928-91 period of record.

Kootenay Lake

As shown in Chart 10, Kootenay Lake was at elevation 1745.6 feet on 31 July. As the inflow receded, Kootenay Lake drafted to below the IJC summer operating level of 1743.32 feet by 30 August. Beginning 1 September and continuing until early October, the discharge at Kootenay Lake was reduced to prevent spilling at the downstream Brilliant project. The lake subsequently filled slowly to near the IJC curve elevation 1745.32 feet by 11 October. During November and December, Kootenay Lake operated primarily between elevations 1744.5 feet and 1745.0 feet, discharging between 18,000 cfs and 40,000 cfs during this period.

Kootenay Lake began drafting according to the IJC curve in early January and continued being drawn down in February and March. Because of the IJC-required draft of the lake, which has precedent over Libby and Duncan flood control draft, and the reduced channel capacity of the lake outlet, especially in February and March, it was necessary to begin reducing the Duncan and Libby discharges on 6 February to keep the Kootenay Lake level from exceeding what is allowed per the IJC Order. By 30 March, Kootenay Lake was drawn down to elevation 1739.1 feet, its lowest level for 1991.

Kootenay Lake began filling on 5 April. During April and May, due both Duncan and Libby being operated to pass inflow, the Lake inflow was well above average, peaking at 97,100 cfs on 19 May. As a result, the lake filled very quickly during this period, reaching an initial peak level of 1749.8 feet on 21 May.

The water level dropped slightly before the reservoir resumed filling, reaching a peak level of 1750.2 feet on 12 June. This was the highest peak level since 1974 when the lake peaked at elevation 1754.2 feet. The maximum discharge during this period was 71,400 cfs, on 13 June, which was much higher than the combined powerhouse capacity of approximately 42,000 cfs at the Kootenay Canal and the Kootenay River projects.

The runoff receded in late June and July. Kootenay Lake was drafted slowly during this period to elevation 1746.3 feet by 31 July. On 25 August, the Kootenay Lake level as measured at the Nelson gage was 1743.31 feet, slightly below the IJC requirement for drafting to 1743.32 feet at Nelson following the spring runoff. The lake continued drafting until 25 August when the outflow was reduced to begin refilling back up to elevation 1745.32 feet per the IJC rule curve.

VI Power and Flood Control Accomplishments

General

During the period covered by this report, Duncan, Arrow, Mica, and Libby reservoirs were operated in accordance with the Columbia River Treaty. Specifically, the operation of the reservoirs was governed by:

1. "Detailed Operating Plan for Columbia River Treaty Storage - 1 August 1990 through 31 July 1991," dated September 1990.
2. "Columbia River Treaty Flood Control Operating Plan," dated October 1972.

Consistent with all Detailed Operating Plans prepared since the installation of generation at Mica, the 1990-91 Detailed Operating Plan was designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States, in accordance with paragraph 7 of Annex A of the Treaty. The 1990-91 Assured Operating Plan, prepared in 1985, was used as the basis for the preparation of the 1990-91 Detailed Operating Plan.

Power

The Canadian Entitlement to downstream power benefits from Duncan, Arrow and Mica for the 1989-90 operating year had been purchased in 1964 by the Columbia Storage Power Exchange (CSPE). In accordance with the Canadian Entitlement Exchange Agreement dated 13 August 1964, the U.S. Entity delivered capacity and energy to the CSPE participants.

The generation at downstream projects in the United States, delivered under the Canadian Entitlement Exchange Agreement was 330 average megawatts at rates up to 1,022 megawatts, from

1 August 1990 through 31 March 1991, and 318 average megawatts, at rates up to 932 megawatts, from 1 April through 31 July 1991. All CSPE power was used to meet Pacific Northwest loads.

The Coordinated System reservoirs were near full on 1 August 1990, and after being drawn down during the 1990-91 operating year, refilled to 99.6 percent of full on 31 July 1991. The following table shows the status of the energy stored in Coordinated System reservoirs at the end of each month compared to operating rule curves during the 1990-91 operating year. Normal full Coordinated System reservoir storage is approximately 63,700 megawatt-months. All figures are 1000 MWMo.

Month	Operating Rule Curve	Actual	Difference
Aug 90	45.6	44.9	- 0.7
Sep 90	43.7	42.5	- 1.2
Oct 90	41.2	39.6	- 1.6
Nov 90	37.5	38.8	+ 1.3
Dec 90	33.4	32.0	- 1.4
Jan 91	16.7	24.8	+ 8.1
Feb 91	11.5	20.7	+ 9.2
Mar 91	8.6	13.9	+ 5.3
Apr 91	8.1	13.0	+ 4.9
May 91	16.9	23.9	+ 7.0
Jun 91	35.9	37.5	+ 1.6
Jul 91	45.4	45.6	+ 0.2

During the January-June period of 1991, volume runoff forecasts for cyclic reservoirs were sufficient to lower the Operating Rule Curves to below Assured Refill Curves, and, as a result, no proportional draft was necessary during this period.

The following table shows BPA nonfirm and surplus firm sales in megawatt-hours to northwest and southwest utilities during the 1990-91 operating year.

PERIOD	TO NORTHWEST UTILITIES NONFIRM	SURPLUS FIRM	TO SOUTHWEST UTILITIES NONFIRM	SURPLUS FIRM
AUG 90	4,900	0	190,225	0
SEP 90	0	2,914	0	0
OCT 90	0	175,772	0	0
NOV 90	53,807	150,840	382,176	0
DEC 91	158,289	250,858	1,211,846	47,602
JAN 91	441,942	113,761	1,245,678	45,338
FEB 91	271,871	100,800	1,443,338	185,524
MAR 91	592,645	99,909	1,647,869	58,437
APR 91	283,774	0	1,701,475	0
MAY 91	670,133	1,811	1,783,351	0
JUN 91	1,015,311	8,000	1,568,742	0
JUL 91	417,292	8,800	609,565	0
TOTAL	3,909,964	913,465	11,784,265	336,901

Flood Control

The Columbia River Basin reservoir system, including the Columbia River Treaty projects, was operated on a daily basis for flood control between 17 May and 18 June. The observed and unregulated hydrographs for the Columbia River at The Dalles between 1 April 1991 and 31 July 1991 are shown on Chart 14. The unregulated peak flow at The Dalles would have been 568,010 cfs and it was controlled to a maximum of 348,000 cfs on 26 May 1991.

The observed peak stage at Vancouver, Washington was 12.6 feet on 21 May 1991 and the unregulated stage would have been 19.1 feet. Chart 15 documents the relative filling of Arrow and Grand Coulee during the principal filling period, and compares the regulation of these two reservoirs to guidelines in the Treaty Flood Control Operating Plan. The major deviation from the guideline curve shown in this plot was caused by the operation of Arrow to protect trout redds below the dam in May and June.

Computations of the Initial Controlled Flow (ICF) for system flood control operation were made in accordance with the Treaty Flood Control Operating Plan. Computed Initial Controlled Flows at The Dalles were 394,000 cfs on 1 January 1991, 370,000 cfs on 1 February, 342,000 cfs on 1 March, 336,000 cfs on 1 April and 337,000 cfs on 1 May. As mentioned earlier, the observed peak flow at The Dalles was 348,000 cfs. Data for the 1 May ICF computation are given in Table 6.

Table 1

Unregulated Runoff Volume Forecasts
Million of Acre-Feet
1991

Forecast Date - 1st of	DUNCAN Most Probable 1 April - 31 August	ARROW Most Probable 1 April - 31 August	MICA Most Probable 1 April - 31 August	LIBBY Most Probable 1 April - 31 August	UNREGULATED RUNOFF COLUMBIA RIVER AT THE DALLES,OREGON Most Probable 1 April - 31 August
January	2.8	29.0	14.4	8.5	103.0
February	2.5	29.0	14.6	8.2	98.1
March	2.4	29.1	14.9	8.0	93.9
April	2.4	27.2	13.4	8.4	94.3
May	2.4	26.1	12.8	8.5	94.3
June	2.4	26.3	13.1	8.6	92.4
Actual	2.4	26.2	13.6	8.5	97.0

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

Table 2

95 Percent Confidence Forecast and Variable Energy Content Curve Mica 1991

	INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
1 PROBABLE FEB 1 - JUL 31 INFLOW, KSFD[1]		6452.6	6075.1	6212.5	5878.5	5900.5	5797.5
2 95% FORECAST ERROR, KSFD		584.5	480.5	444.1	414.4	380.9	378.8
3 95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD[2] ..		5868.1	5594.6	5768.4	5464.1	5519.6	5418.7
4 OBSERVED FEB 1 - DATE INFLOW, KSFD		0.0	0.0	183.7	305.2	613.0	1675.3
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD[3]		5868.1	5594.6	5584.7	5158.9	4906.6	3743.4
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME ..		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD[4]		5868.1					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		2180.0					
MIN. JAN 31 RESERVOIR CONTENT, KSFD[5]		-158.9					
MIN. JAN 31 RESERVOIR ELEVATION, FT[6]		2394.1					
JAN 31 ECC, FT[7]		2416.9					
BASE ECC, FT	2436.1						
LOWER LIMIT, FT	2416.9						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME ..		97.8	97.8				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD[4]		5739.0	5471.5				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		1760.0	1760.0				
MIN. FEB 28 RESERVOIR CONTENT, KSFD[5]		-449.8	-182.3				
MIN. FEB 28 RESERVOIR ELEVATION, FT[6]		2394.1	2394.1				
FEB 28 ECC, FT[7]		2402.4	2402.4				
BASE ECC, FT	2423.3						
LOWER LIMIT, FT	2402.4						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME ..		95.4	95.4	97.6			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD[4]		5598.2	5337.2	5450.7			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		1295.0	1295.0	1295.0			
MIN. MAR 31 RESERVOIR CONTENT, KSFD[5]		-774.0	-513.0	-626.5			
MIN. MAR 31 RESERVOIR ELEVATION, FT[6]		2394.1	2394.1	2394.1			
MAR 31 ECC, FT[7]		2394.1	2394.1	2394.1			
BASE ECC, FT	2411.4						
LOWER LIMIT, FT	2394.1						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME ..		90.7	90.7	92.8	95.1		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD[4]		5322.4	5074.3	5182.6	4906.1		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		920.0	920.0	920.0	920.0		
MIN. APR 30 RESERVOIR CONTENT, KSFD[5]		-873.2	-625.1	-733.4	-456.9		
MIN. APR 30 RESERVOIR ELEVATION, FT[6]		2394.1	2394.1	2394.1	2394.1		
APR 30 ECC, FT[7]		2394.1	2394.1	2394.1	2394.1		
BASE ECC, FT	2402.8						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME ..		73.2	73.2	74.9	76.8	80.8	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD[4]		4295.4	4095.2	4182.9	3962.0	3964.5	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		610.0	610.0	610.0	610.0	610.0	
MIN. MAY 31 RESERVOIR CONTENT, KSFD[5]		-156.2	44.0	-43.7	177.2	174.7	
MIN. MAY 31 RESERVOIR ELEVATION, FT[6]		2394.1	2395.3	2394.1	2398.6	2398.5	
MAY 31 ECC, FT[7]		2394.1	2395.3	2394.1	2398.6	2398.5	
BASE ECC, FT	2411.4						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME ..		36.7	36.7	37.5	38.5	40.5	50.1
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD[4]		2153.6	2053.2	2094.3	1986.2	1987.2	1875.4
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		310.0	310.0	310.0	310.0	310.0	310.0
MIN. JUN 30 RESERVOIR CONTENT, KSFD[5]		1685.6	1786.0	1744.9	1853.0	1852.0	1963.8
MIN. JUN 30 RESERVOIR ELEVATION, FT[6]		2433.1	2435.2	2434.3	2436.6	2436.6	2438.9
JUN 30 ECC, FT[7]		2433.1	2435.2	2434.3	2436.6	2436.6	2438.9
BASE ECC, FT	2441.5						
JUL 31 ECC, FT	2470.1	2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

1 DEVELOPED BY CANADIAN ENTITY
2 LINE 1 - LINE 2
3 LINE 3 - LINE 4
4 PRECEDING LINE X LINE 5
5 FULL CONTENT (3529.2 KSFD) PLUS TWO PRECEDING LINES LESS LINE PRECEDING THAT
6 FROM RESERVOIR ELEVATION - STORAGE CONTENT TABLE DATED FEBRUARY 21, 1973
7 LOWER OF ELEVATION ON PRECEDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR

95 Percent Confidence Forecast and Variable Energy Content Curve Arrow 1991

	INITIAL	JAN 1 LOCAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1 PROBABLE FEB 1 - JUL 31 INFLOW, KSFD[1]		6845.6	12740.1	12946.6	12504.2	12718.2	12670.4
2 95% FORECAST ERROR, KSFD		956.5	1060.7	936.8	795.5	715.8	779.2
3 95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD[2] ..		5889.1	11679.4	12009.8	11708.7	12002.4	11891.2
4 OBSERVED FEB 1 - DATE INFLOW, KSFD		0.0	0.0	478.0	898.4	1723.4	4256.1
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD[3]		5889.1	11679.4	11531.8	10810.3	10279.0	7635.1
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME ..		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD[4]		5889.1					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		1440.0					
MICA REFILL REQUIREMENTS, KSFD[9]		2180.0					
MIN. JAN 31 RESERVOIR CONTENT, KSFD[5]		-3049.5					
MIN. JAN 31 RESERVOIR ELEVATION, FT[6]		1377.9					
JAN 31 ECC, FT[7]		1402.0					
BASE ECC, FT	1431.0						
LOWER LIMIT, FT	1402.0						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME ..		96.8	97.3				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD[4]		5700.6	11364.1				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		1300.0	1300.0				
MICA REFILL REQUIREMENTS, KSFD[9]		1760.0	3195.7				
MIN. FEB 28 RESERVOIR CONTENT, KSFD[5]		-2581.1	-3288.8				
MIN. FEB 28 RESERVOIR ELEVATION, FT[6]		1377.9	1377.9				
FEB 28 ECC, FT[7]		1387.1	1393.9				
BASE ECC, FT	1429.7						
LOWER LIMIT, FT	1393.9						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME ..		93.1	94.2	96.9			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD[4]		5482.7	11002.0	11174.3			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		1145.0	1145.0	1336.7			
MICA REFILL REQUIREMENTS, KSFD[9]		1295.0	3532.1	3532.1			
MIN. MAR 31 RESERVOIR CONTENT, KSFD[5]		-2053.2	-2745.3	-2725.9			
MIN. MAR 31 RESERVOIR ELEVATION, FT[6]		1377.9	1377.9	1377.9			
MAR 31 ECC, FT[7]		1379.5	1379.5	1379.5			
BASE ECC, FT	1424.3						
LOWER LIMIT, FT	1379.5						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME ..		85.2	87.9	90.4	93.3		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD[4]		5017.5	10266.2	10424.7	10086.0		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		920.0	920.0	1091.7	920.0		
MICA REFILL REQUIREMENTS, KSFD[9]		920.0	3532.1	3532.1	3532.1		
MIN. APR 30 RESERVOIR CONTENT, KSFD[5]		-1437.9	-2234.5	-2221.4	-2054.3		
MIN. APR 30 RESERVOIR ELEVATION, FT[6]		1377.9	1377.9	1377.9	1377.9		
APR 30 ECC, FT[7]		1377.9	1377.9	1377.9	1377.9		
BASE ECC, FT	1420.6						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME ..		61.3	67.3	69.1	71.3	76.4	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD[4]		3610.0	7848.6	7968.5	7707.7	7853.2	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		610.0	610.0	723.9	610.0	695.4	
MICA REFILL REQUIREMENTS, KSFD[9]		610.0	3485.2	3532.1	3352.0	3354.5	
MIN. MAY 31 RESERVOIR CONTENT, KSFD[5]		-30.4	-173.7	-132.9	-166.1	-223.6	
MIN. MAY 31 RESERVOIR ELEVATION, FT[6]		1377.9	1377.9	1377.9	1377.9	1377.9	
MAY 31 ECC, FT[7]		1377.9	1377.9	1377.9	1377.9		
BASE ECC, FT	1431.3						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME ..		26.7	31.1	32.0	33.0	35.4	46.3
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD[4]		1572.4	3632.3	3690.2	3567.4	3638.8	3535.1
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		310.0	310.0	367.9	310.0	353.4	367.9
MIN. JUN 30 RESERVOIR CONTENT, KSFD[5]		310.0	1743.2	1784.3	1676.2	1677.2	1565.4
MICA REFILL REQUIREMENTS, KSFD[9]		2007.2	2000.5	2041.6	1998.4	1971.4	1977.9
MIN. JUN 30 RESERVOIR ELEVATION, FT[6]		1418.4	1418.3	1419.0	1418.3	1417.8	1417.9
JUN 30 ECC, FT[7]		1418.4	1418.3	1419.0	1418.3	1417.8	1417.9
BASE ECC, FT	1442.9						
JUL 31 ECC, FT	1444.0	1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

1 DEVELOPED BY CANADIAN ENTITY
2 LINE 1 - LINE 2
3 LINE 3 - LINE 4
4 PRECEDING LINE X LINE 5
5 FULL CONTENT (3579.6 KSFD) PLUS TWO PRECEDING LINES LESS LINE PRECEDING THAT
6 FROM RESERVOIR ELEVATION - STORAGE CONTENT TABLE DATED FEBRUARY 21, 1973
7 LOWER OF ELEVATION ON PRECEDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR
8 FOR ARROW LOCAL: MICA MINIMUM POWER DISCHARGE
9 FOR ARROW TOTAL: MICA FULL CONTENT LESS ENERGY CONTENT CURVE

Table 4

95 Percent Confidence Forecast and Variable Energy Content Curve Duncan 1991

	INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
1 PROBABLE FEB 1 - JUL 31 INFLOW, KSFD[1]		1199.4	1070.5	1079.7	1028.1	1050.0	1060.7
2 95% FORECAST ERROR, KSFD		107.3	98.4	93.8	94.3	84.4	86.7
3 95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD[2]		1092.1	972.1	985.9	933.8	965.6	974.0
4 OBSERVED FEB 1 - DATE INFLOW, KSFD		0.0	0.0	25.8	47.1	105.6	321.5
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD[3]		1092.1	972.1	960.1	886.7	860.0	652.5
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD[4]		1092.1					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		18.1					
MIN. JAN 31 RESERVOIR CONTENT, KSFD[5]		-368.2					
MIN. JAN 31 RESERVOIR ELEVATION, FT[6]		1794.2					
JAN 31 ECC, FT[7]		1837.2					
BASE ECC, FT	1837.6						
LOWER LIMIT, FT	1837.2						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		97.9	97.9				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD[4]		1069.2	951.7				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		15.3	15.3				
MIN. FEB 28 RESERVOIR CONTENT, KSFD[5]		-348.1	-230.6				
MIN. FEB 28 RESERVOIR ELEVATION, FT[6]		1794.2	1794.2				
FEB 28 ECC, FT[7]		1807.7	1807.7				
BASE ECC, FT	1810.3						
LOWER LIMIT, FT	1807.7						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		95.4	95.4	97.5			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD[4]		1041.9	927.4	936.1			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		12.2	12.2	12.2			
MIN. MAR 31 RESERVOIR CONTENT, KSFD[5]		-323.9	-209.4	-218.1			
MIN. MAR 31 RESERVOIR ELEVATION, FT[6]		1794.2	1794.2	1794.2			
MAR 31 ECC, FT[7]		1802.5	1802.5	1802.5			
BASE ECC, FT	1812.7						
LOWER LIMIT, FT	1802.5						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		89.9	89.9	91.9	94.3		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD[4]		981.8	873.9	882.3	836.2		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		9.2	9.2	9.2	9.2		
MIN. APR 30 RESERVOIR CONTENT, KSFD[5]		-266.8	-158.9	-167.3	-121.2		
MIN. APR 30 RESERVOIR ELEVATION, FT[6]		1794.2	1794.2	1794.2	1794.2		
APR 30 ECC, FT[7]		1798.1	1798.1	1798.1	1798.1		
BASE ECC, FT	1839.9						
LOWER LIMIT, FT	1798.1						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		69.4	69.4	71.8	72.8	77.2	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD[4]		757.9	674.6	681.7	645.5	663.9	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		6.1	6.1	6.1	6.1	6.1	
MIN. MAY 31 RESERVOIR CONTENT, KSFD[5]		-46.0	37.3	30.2	66.4	48.0	
MIN. MAY 31 RESERVOIR ELEVATION, FT[6]		1794.2	1802.5	1801.1	1807.9	1804.5	
MAY 31 ECC, FT[7]		1794.2	1802.5	1801.1	1807.9	1804.5	
BASE ECC, FT	1839.9						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		32.9	32.9	33.6	34.4	36.5	47.3
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD[4]		359.3	319.8	322.6	305.0	313.9	308.6
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		3.1	3.1	3.1	3.1	3.1	3.1
MIN. JUN 30 RESERVOIR CONTENT, KSFD[5]		349.6	389.1	386.3	403.9	395.0	400.3
MIN. JUN 30 RESERVOIR ELEVATION, FT[6]		1849.4	1854.4	1854.1	1856.3	1853.2	1855.9
JUN 30 ECC, FT[7]		1849.4	1854.4	1854.1	1856.3	1855.2	1855.9
BASE ECC, FT	1868.2						
JUL 31 ECC, FT		1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

1 DEVELOPED BY CANADIAN ENTITY
2 LINE 1 - LINE 2
3 LINE 3 - LINE 4
4 PRECEDING LINE X LINE 5
5 FULL CONTENT (705.8 KSFD) PLUS PRECEDING LINE LESS LINE PRECEDING THAT
6 FROM RESERVOIR ELEVATION - STORAGE CONTENT TABLE DATED FEBRUARY 21, 1973
7 LOWER OF ELEVATION ON PRECEDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR

Table 5

95 Percent Confidence Forecast and Variable Energy Content Curve Libby 1991

	INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
1 PROBABLE JAN 1 - JUL 31 INFLOW, KSFD		4175.0	4124.3	4102.2	4311.2	4341.4	3862.1
2 95% FORECAST ERROR, KSFD		886.8	606.4	552.5	533.4	474.5	367.5
3 OBSERVED JAN 1 - DATE INFLOW, KSFD		0.0	150.9	310.8	450.8	805.7	1358.9
4 95% CONF DATE - JUL 31 INFLOW, KSFD[1]		3288.2	3366.9	3238.8	3327.0	3061.2	2135.7
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		97.1					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD[2]		3194.2					
FEB MINIMUM FLOW REQUIREMENTS, CFS[3]		4000.0					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD[4]		1007.0					
MIN. JAN 31 RESERVOIR CONTENT, KSFD[5]		323.3					
MIN. JAN 31 RESERVOIR ELEVATION, FT[6]		2323.5					
JAN 31 ECC, FT[7]		2323.5					
BASE ECC, FT	2430.3						
LOWER LIMIT, FT	2288.5						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		94.5	97.3				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD[4]		3106.4	3274.3				
MAR MINIMUM FLOW REQUIREMENT, CFS[3]		4500.0	4500.0				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD[4]		895.0	895.0				
MIN. FEB 1 RESERVOIR CONTENT, KSFD[5]		299.1	131.2				
MIN. FEB 1 RESERVOIR ELEVATION, FT[6]		2321.2	2303.1				
FEB 28 ECC, FT[7]		2321.2	2303.1				
BASE ECC, FT	2427.7						
LOWER LIMIT, FT	2287.0						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		91.2	93.9	96.6			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD[4]		3000.2	3162.2	3128.0			
APR MINIMUM FLOW REQUIREMENT, CFS[3]		4500.0	4500.0	4633.3			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD[4]		755.5	755.5	769.6			
MIN. MAR 31 RESERVOIR CONTENT, KSFD[5]		265.8	103.8	152.1			
MIN. MAR 31 RESERVOIR ELEVATION, FT[6]		2317.7	2300.1	2305.5			
MAR 31 ECC, FT[7]		2317.7	2300.1	2305.5			
BASE ECC, FT	2420.0						
LOWER LIMIT, FT	2287.0						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		83.2	85.7	88.1	91.2		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD[4]		2736.1	2883.8	2852.7	3034.2		
MAY MINIMUM FLOW REQUIREMENT, CFS[3]		6000.0	6000.0	6000.0	6000.0		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD[4]		613.0	613.0	621.1	613.0		
MIN. APR 30 RESERVOIR CONTENT, KSFD[5]		387.4	239.7	278.9	89.3		
MIN. APR 30 RESERVOIR ELEVATION, FT[6]		2329.8	2315.0	2319.1	2298.2		
APR 30 ECC, FT[7]		2329.8	2315.0	2319.1	2298.2		
BASE ECC, FT	2419.1						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		56.9	57.5	59.1	61.2	67.1	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD[4]		1869.7	1936.0	1915.1	2036.8	2055.0	
JUN MINIMUM FLOW REQUIREMENT, CFS[3]		7000.0	7000.0	7133.3	7000.0	7100.0	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD[4]		427.0	427.0	435.1	427.0	433.1	
MIN. MAY 31 RESERVOIR CONTENT, KSFD[5]		1067.8	1001.5	1030.5	900.7	888.6	
MIN. MAY 31 RESERVOIR ELEVATION, FT[6]		2384.2	2379.6	2381.7	2372.4	2371.5	
MAY 31 ECC, FT[7]		2384.2	2379.6	2381.7	2372.4	2371.5	
BASE ECC, FT	2441.3						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		19.4	20.0	20.5	21.3	23.3	34.7
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD[4]		638.2	672.7	665.3	707.7	713.9	741.9
JUN MINIMUM FLOW REQUIREMENT, CFS[3]		7000.0	7000.0	7133.3	7000.0	7100.0	7133.3
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD[4]		217.0	217.0	221.1	217.0	220.1	221.1
MIN. JUN 30 RESERVOIR CONTENT, KSFD[5]		2089.3	2054.8	2066.4	2019.8	2016.7	1989.7
MIN. JUN 30 RESERVOIR ELEVATION, FT[6]		2440.3	2438.7	2439.2	2437.0	2436.9	2435.6
JUN 30 ECC, FT[7]		2440.3	2438.7	2439.2	2437.0	2436.9	2435.6
BASE ECC, FT	2459.0						
JUL 31 ECC, FT		2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
JAN 1 - JUL 31 FORECAST, EARLYBIRD, MAF[8] (AT THE DALLES)		112.0	111.0	106.0	110.0	107.0	106.0

1 LINE 1 - LINE 2 LINE 3
2 PRECEDING LINE TIMES LINE 4
3 BASED ON POWER DISCHARGE REQUIREMENTS, DETERMINED FROM 8
4 CUMULATIVE MINIMUM OUTFLOW FROM 3, FROM DATE TO JULY
5 FULL CONTENT (2510.5 KSFD) PLUS 4, AND MINUS 2
6 ELEVATION FROM 5, STORAGE CONTENT TABLE, DATED JUNE 1980
7 ELEVATION FROM 6, BUT LIMITED BASE ECC, AND ECC LOWER LIMIT
8 USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3

Table 6

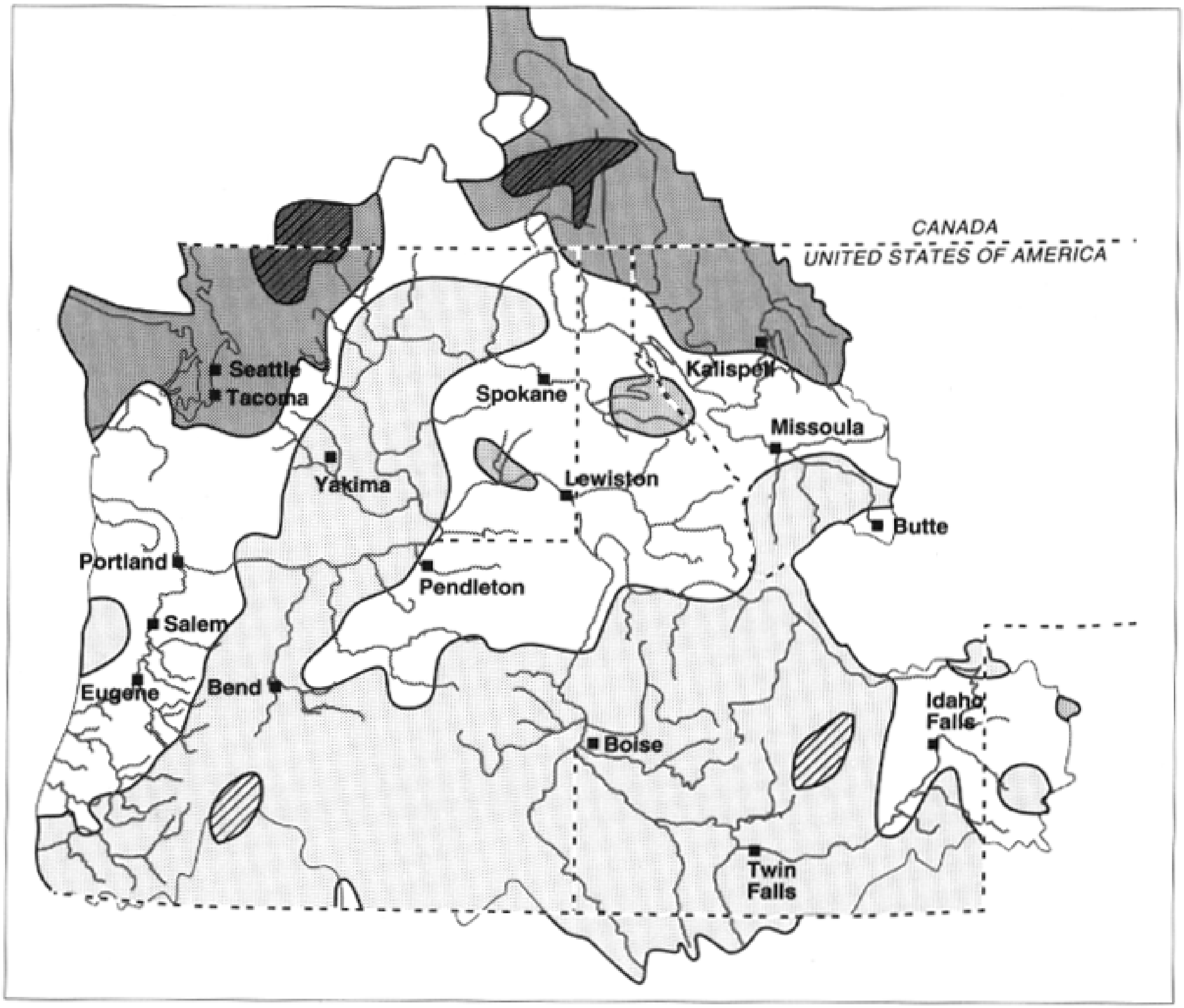
Computation of Initial Controlled Flow
Columbia River at The Dalles
1 May 1991

1 May Forecast of May-August Unregulated Runoff Volume, MAF		81.8
Less Estimated Depletions, MAF		1.5
Less Upstream Storage Corrections, MAF		
MICA	7.8	
ARROW	5.0	
DUNCAN	1.3	
LIBBY	5.0	
LIBBY + DUNCAN UNDER DRAFT*	-0.7	
HUNGRY HORSE	1.9	
FLATHEAD LAKE	0.5	
NOXON	0.0	
PEND OREILLE LAKE	0.5	
GRAND COULEE	4.5	
BROWNLEE	0.0	
DWORSHAK	1.2	
JOHN DAY	0.2	
TOTAL	27.1	28.6
Forecast of Adjusted Residual Runoff Volume, MAF		53.2
Computed Initial Controlled Flow from Chart 1 of Flood Control Operating Plan, 1,000 cfs		337.0

* Due to the IJC rule curve requirements at Kootenay Lake, it was not possible to evacuate all the required flood control space at Duncan and Libby.

Chart 1

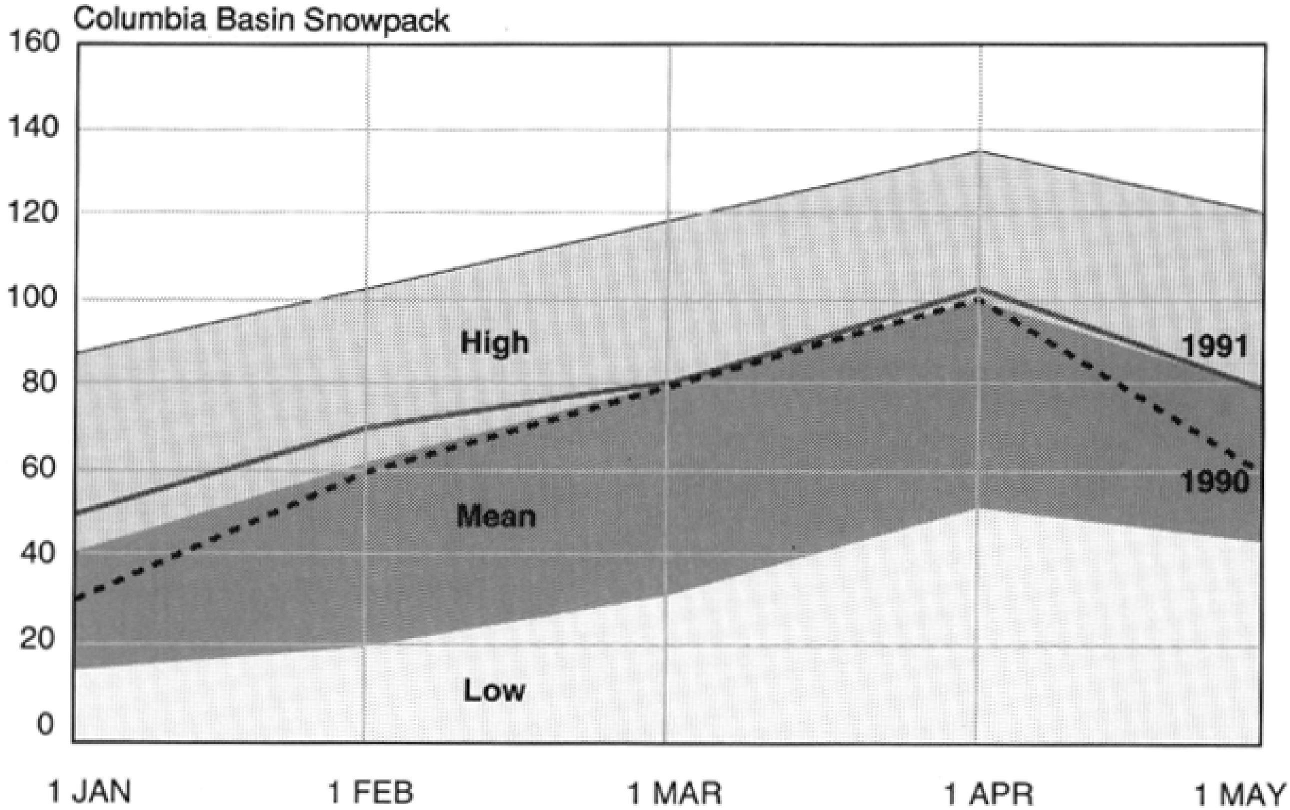
Seasonal Precipitation
Columbia River Basin
October 1990 - March 1991
Percent of 1961 -1985 Average

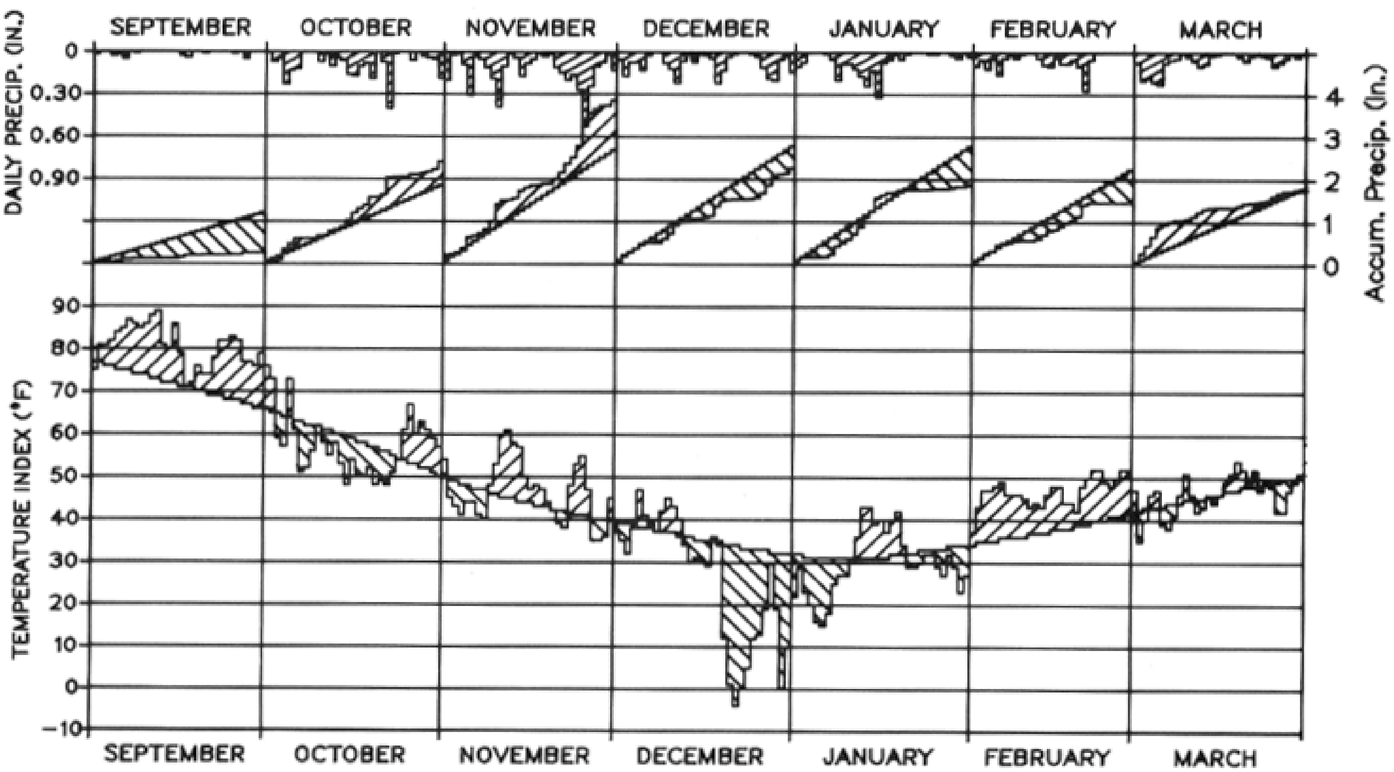


- Precipitation very high and more than 150% of average
- Precipitation high and more than 120% of average
- Precipitation low and more than 80% of average
- Precipitation very low and more than 50% of average

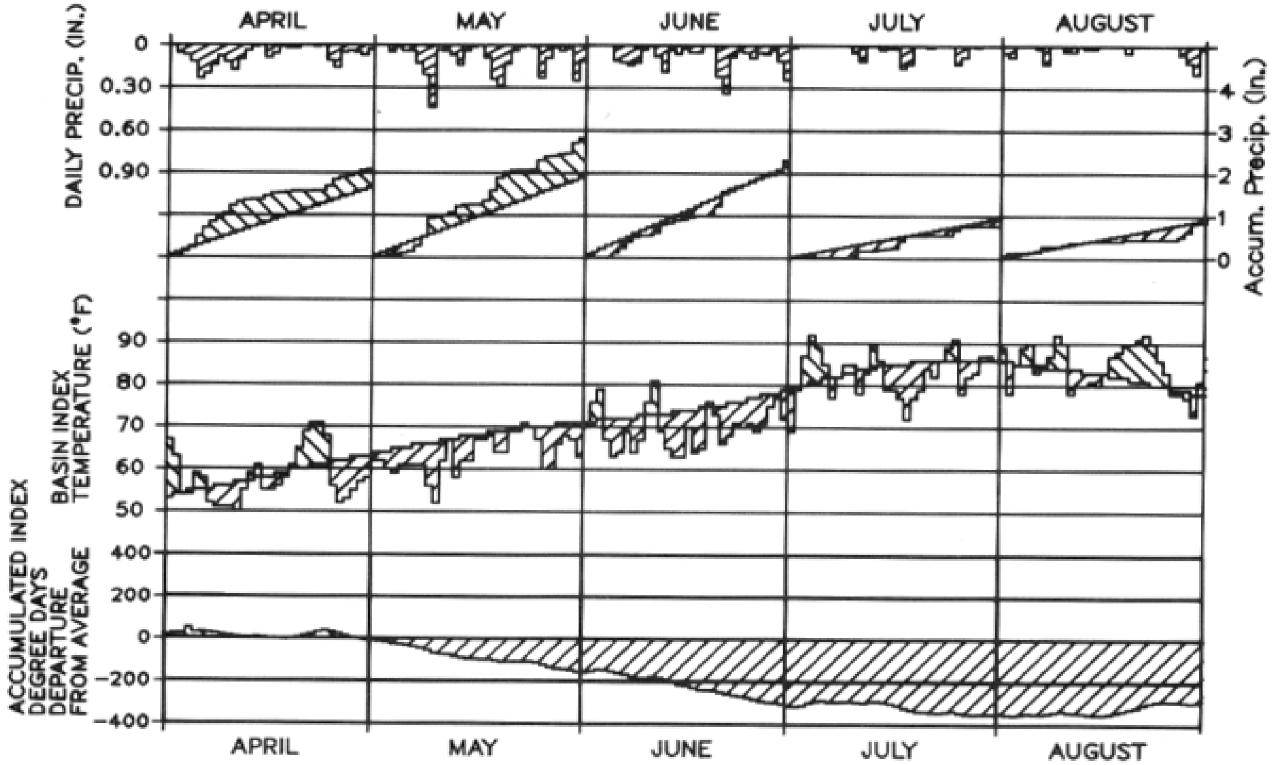
Information prepared by
NATIONAL WEATHER SERVICE
Northwest River Forcast Center
Portland, Oregon

Chart 2
Columbia Basin Snowpack

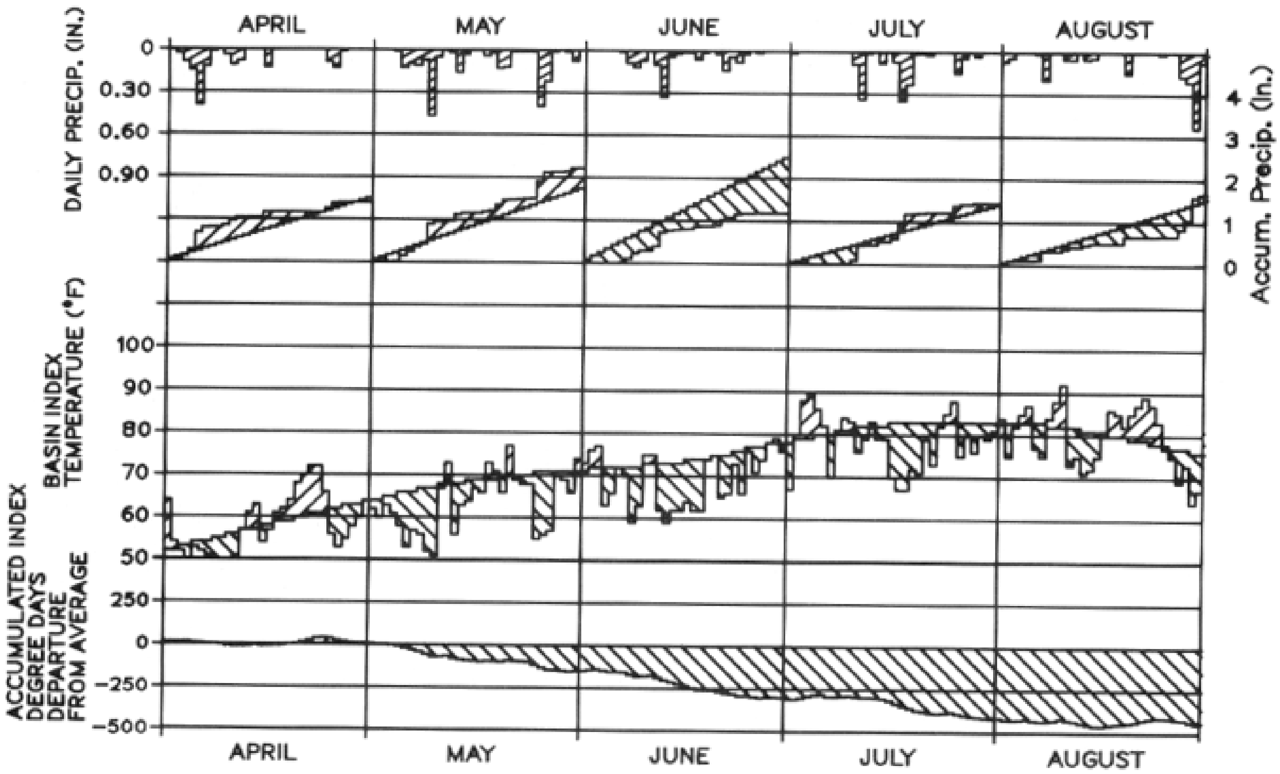




WINTER SEASON Chart 3
TEMPERATURE AND PRECIPITATION INDEX 1990–1991
Columbia River Basin Above The Dalles, OR

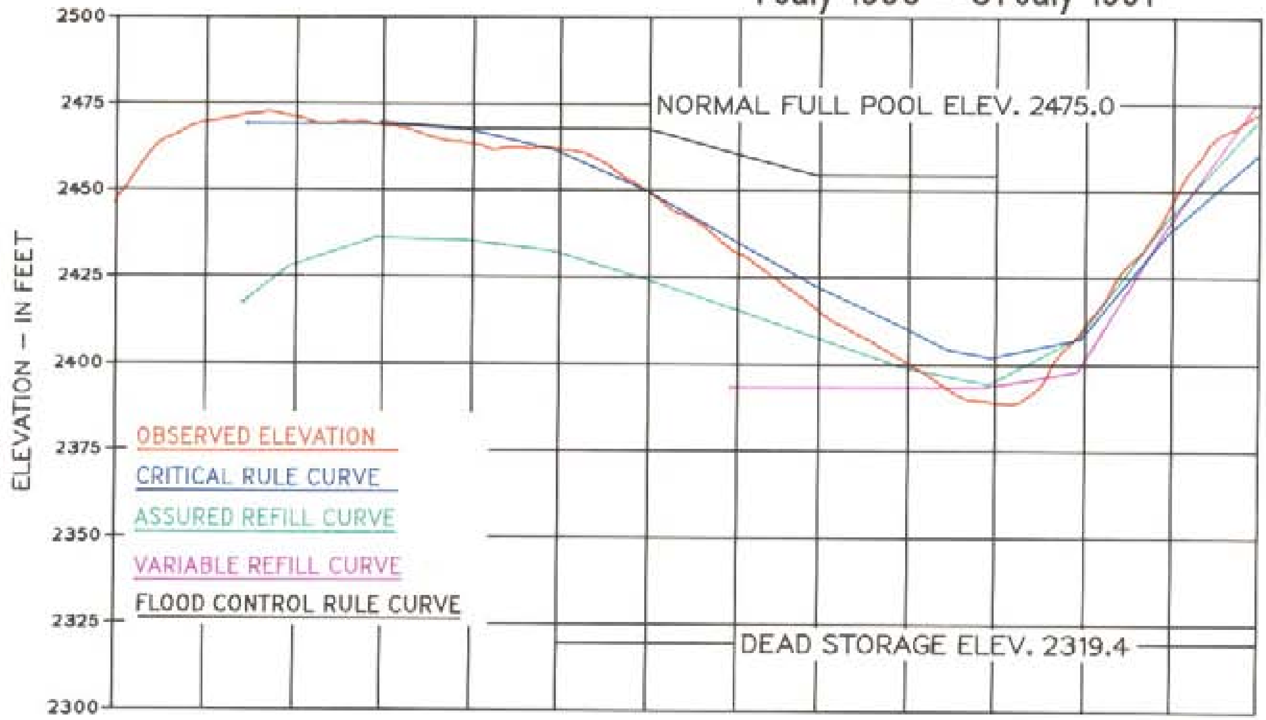


1991 SNOWMELT SEASON CHART 4
TEMPERATURE AND PRECIPITATION INDEX
Columbia River Basin Above The Dalles, OR



1991 SNOWMELT SEASON Chart 5
TEMPERATURE AND PRECIPITATION INDEX
Columbia River Basin In Canada

Chart 6
Regulation of Mica
1 July 1990 – 31 July 1991



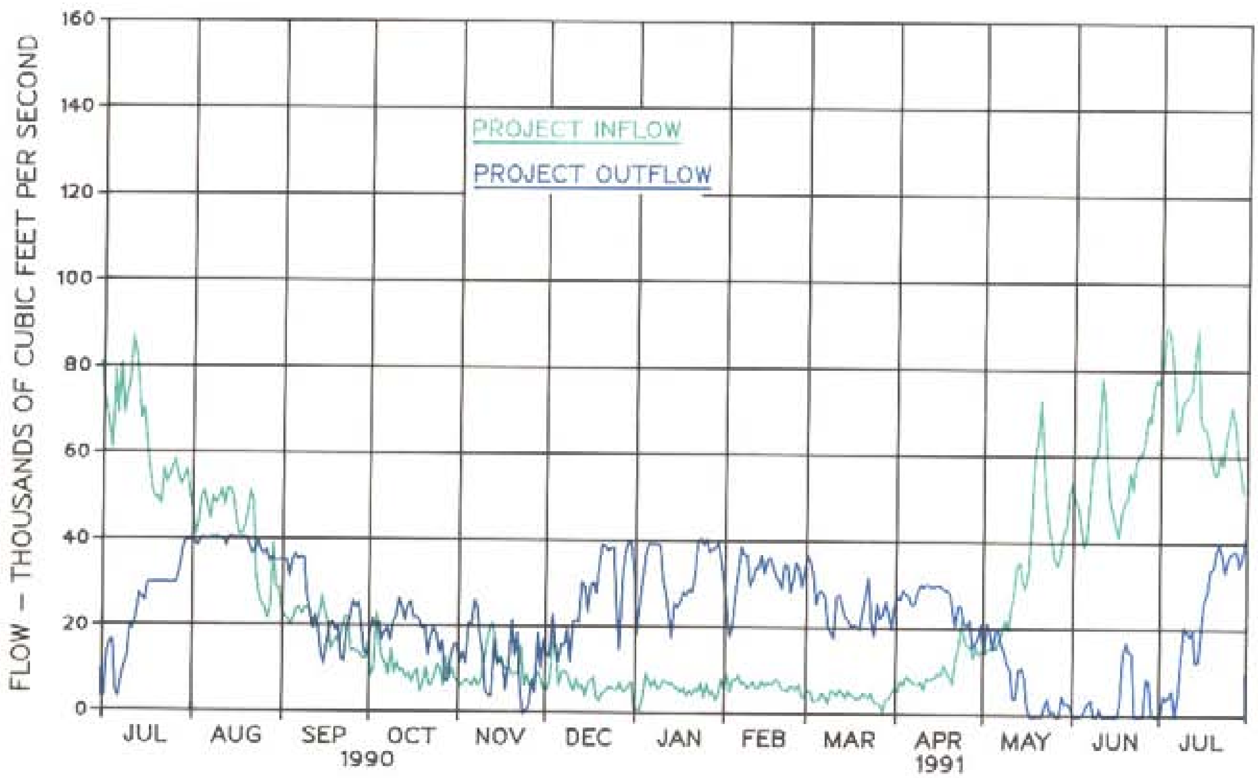
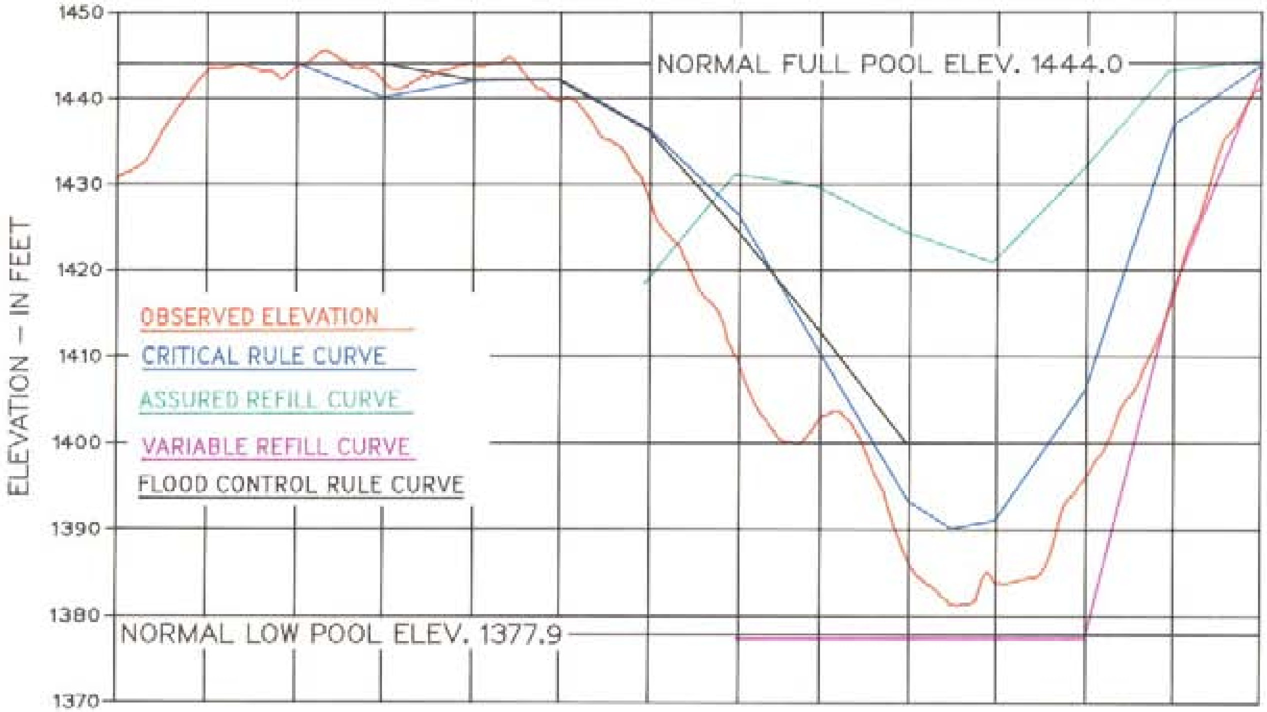


Chart 7
Regulation of Arrow
1 July 1990 – 31 July 1991



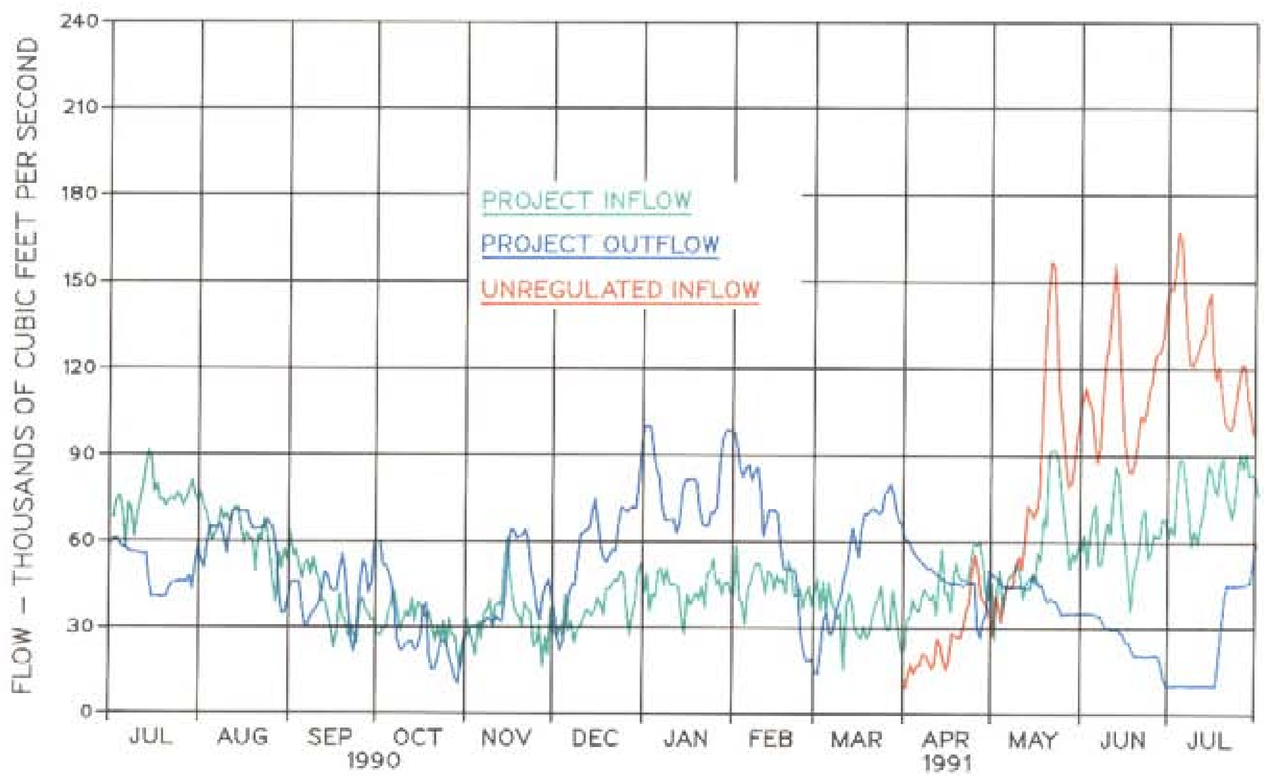
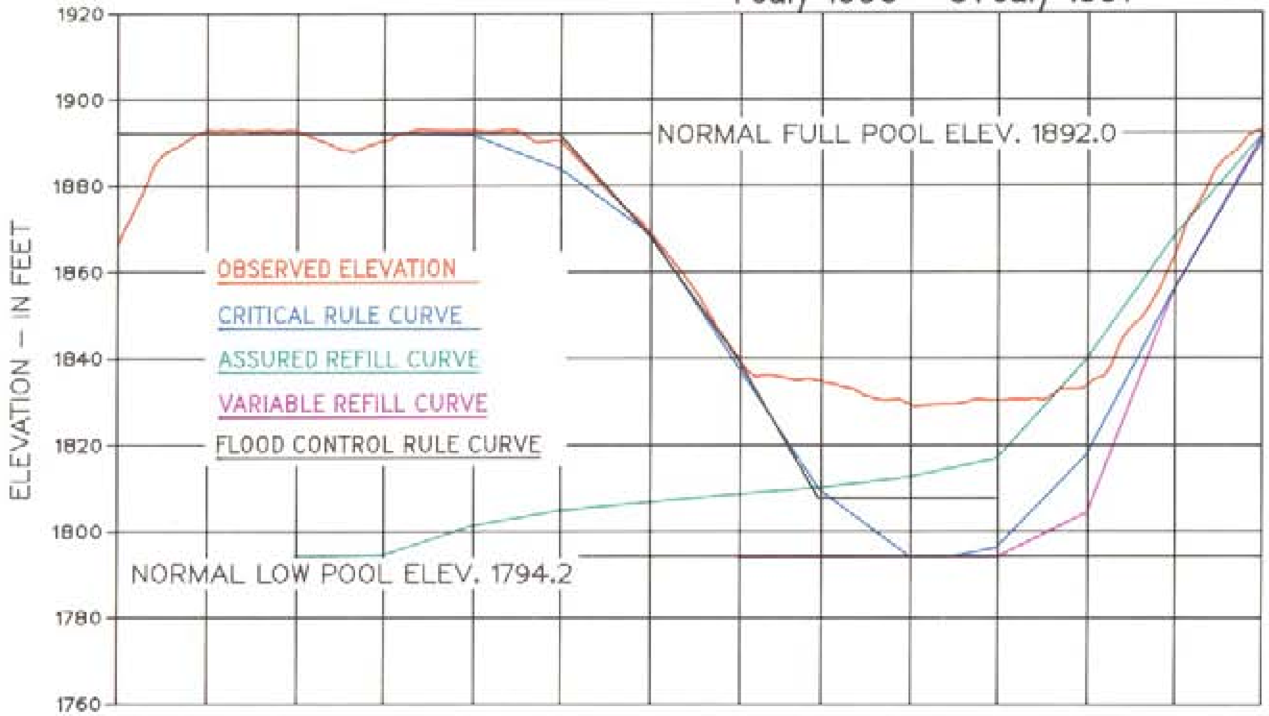


Chart 8
Regulation of Duncan
1 July 1990 – 31 July 1991



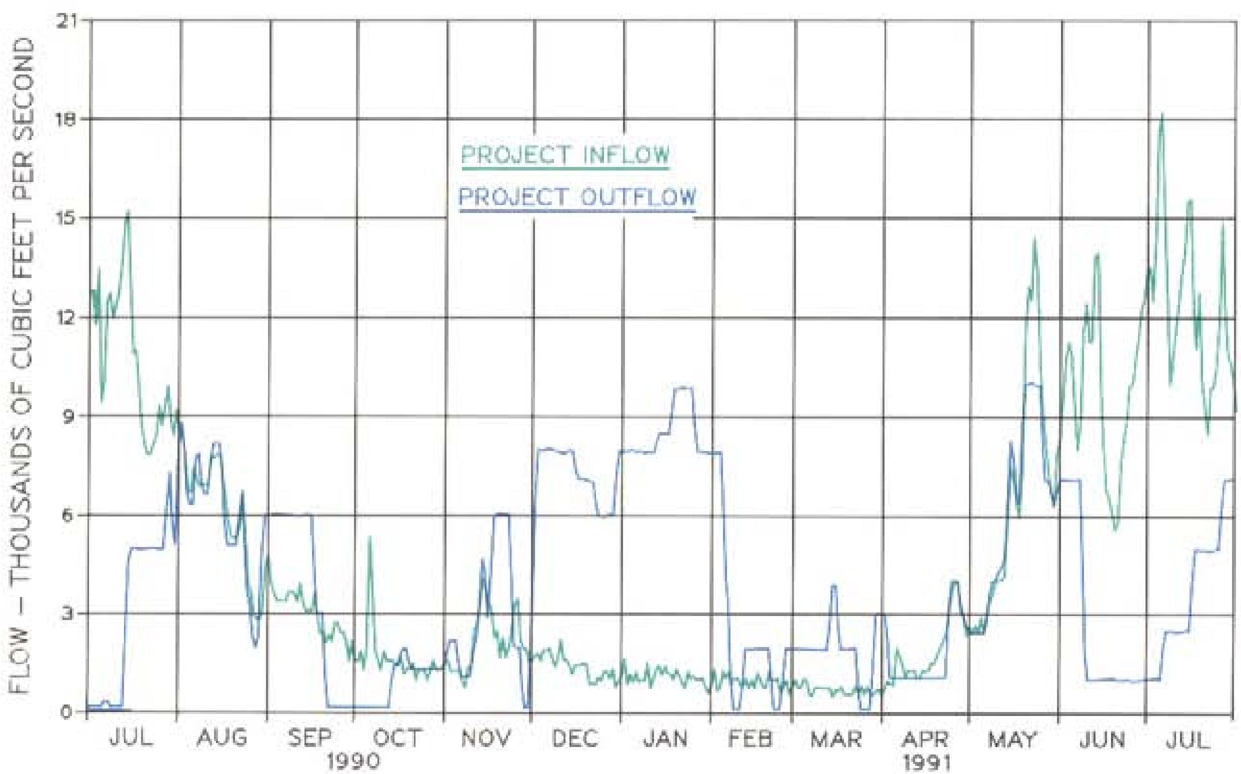
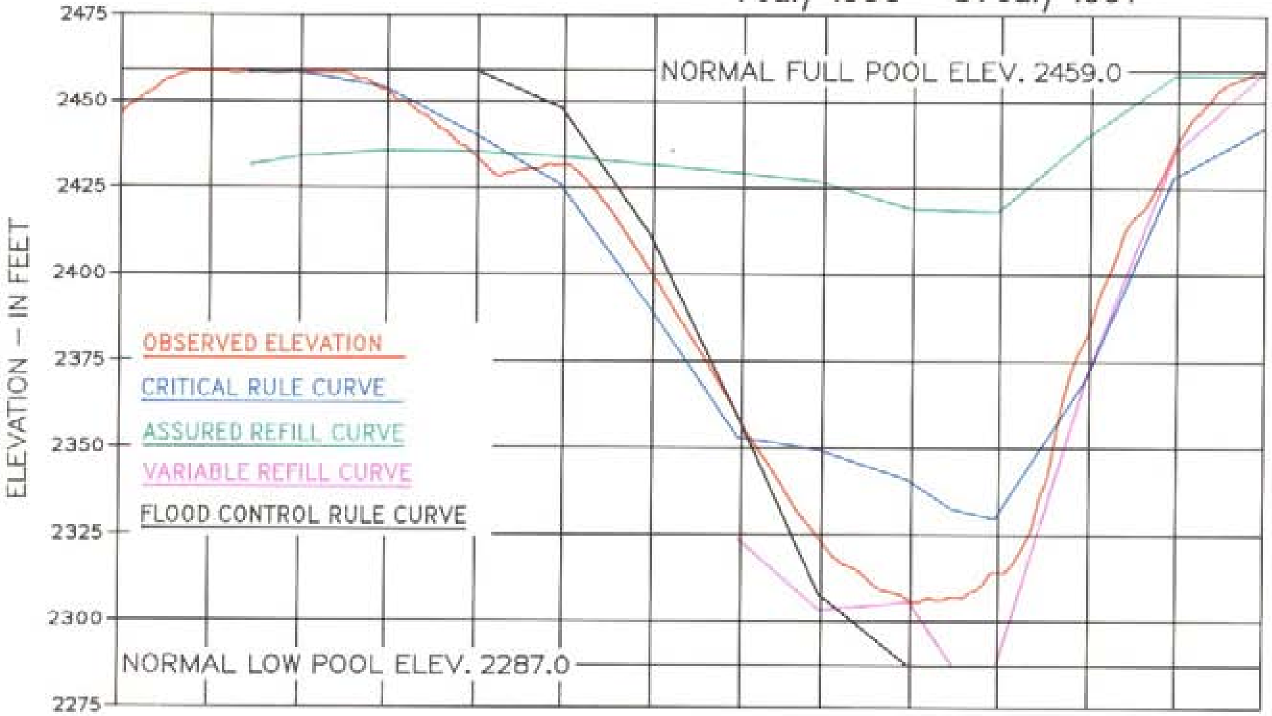


Chart 9
Regulation of Libby
1 July 1990 – 31 July 1991



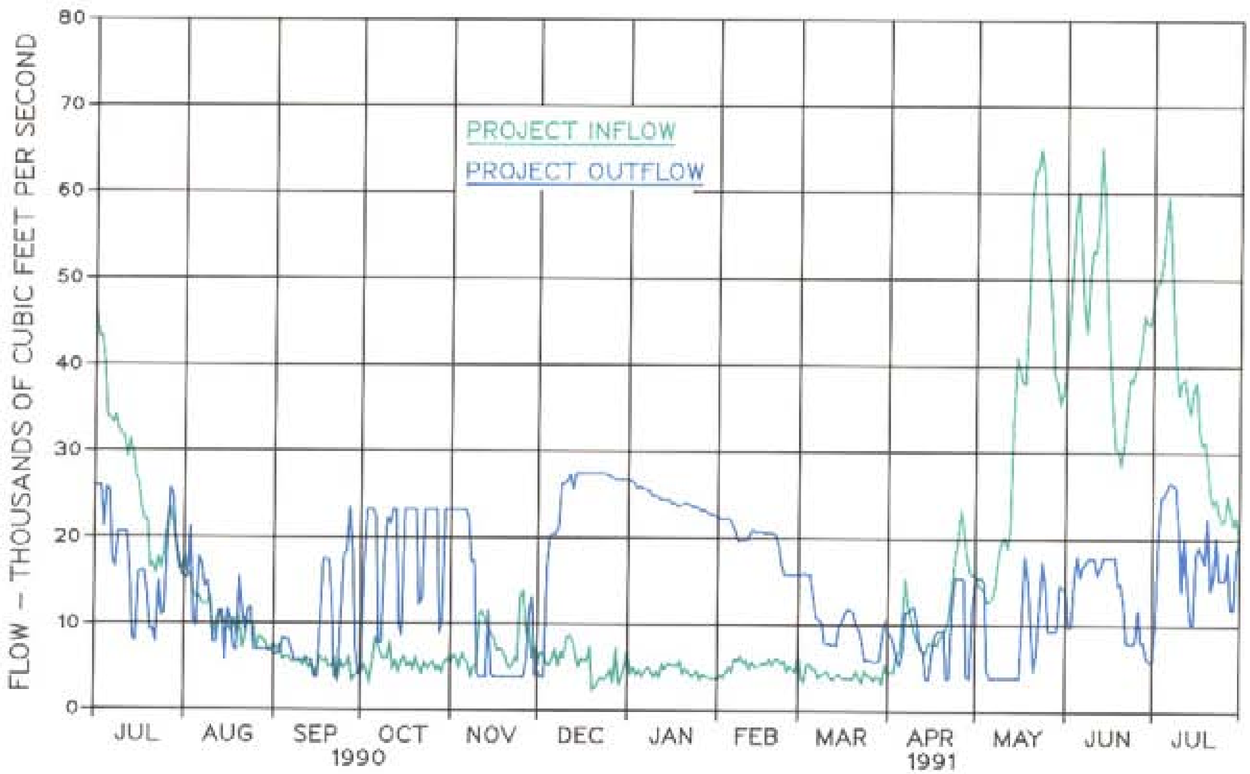


Chart 10
Regulation of Kootenay Lake
1 July 1990 – 31 July 1991

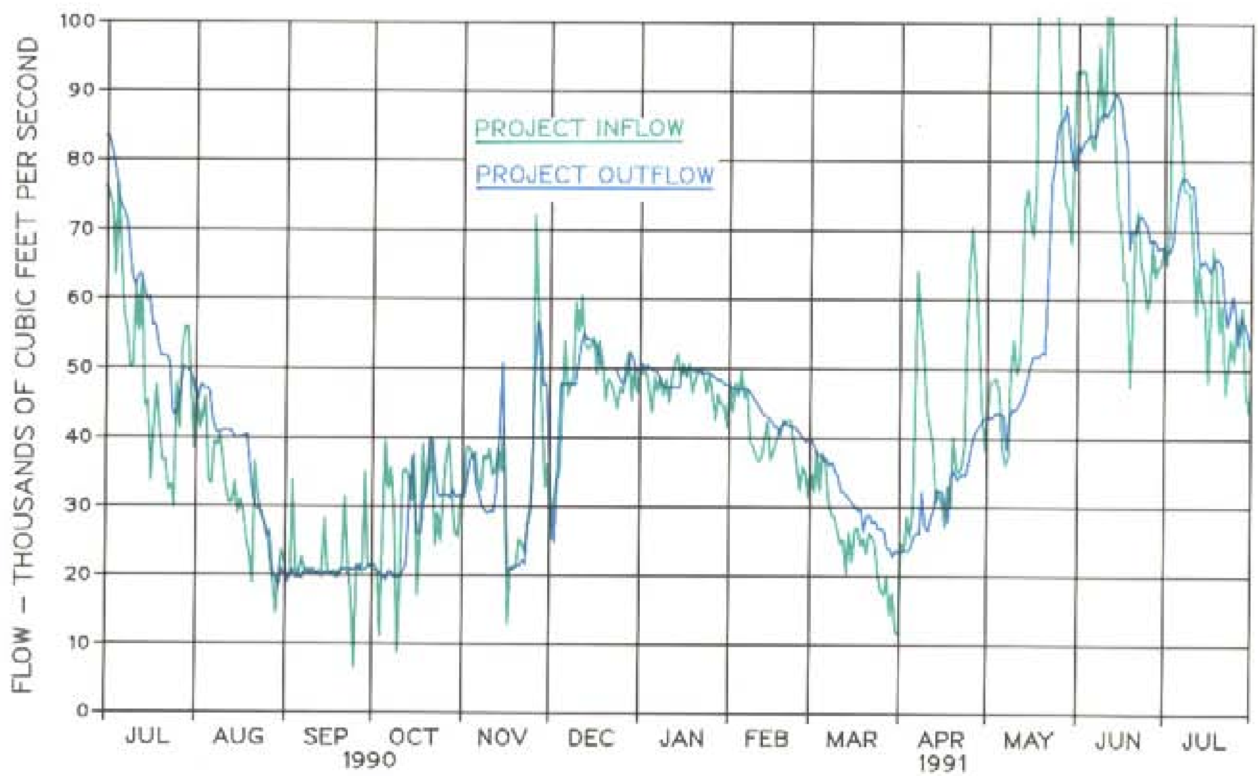


Chart 11
Columbia River at Birchbank
1 July 1990 – 31 July 1991

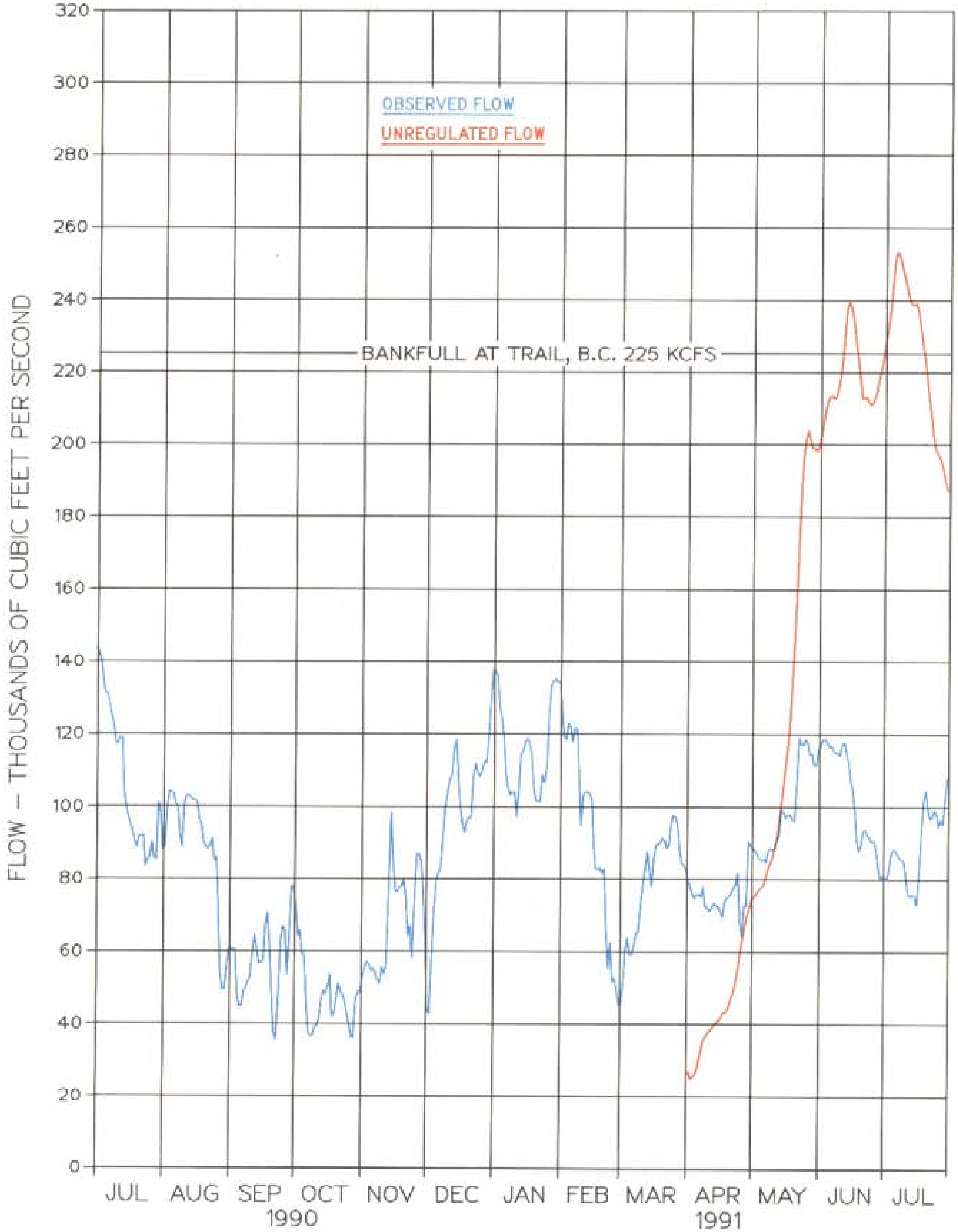


Chart 12
Regulation of Grand Coulee
1 July 1990 – 31 July 1991

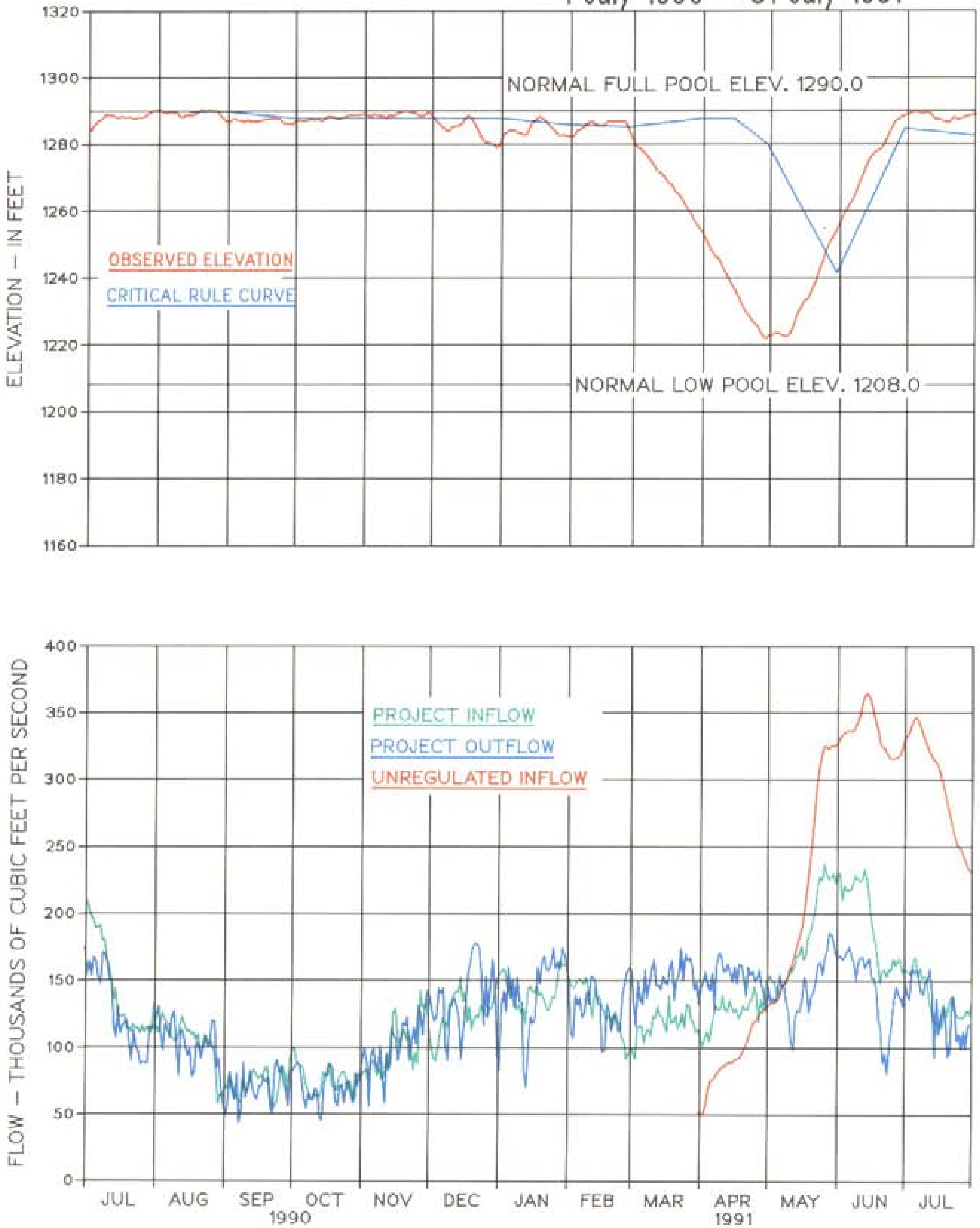


Chart 13
Columbia River at The Dalles
1 July 1990 – 31 July 1991

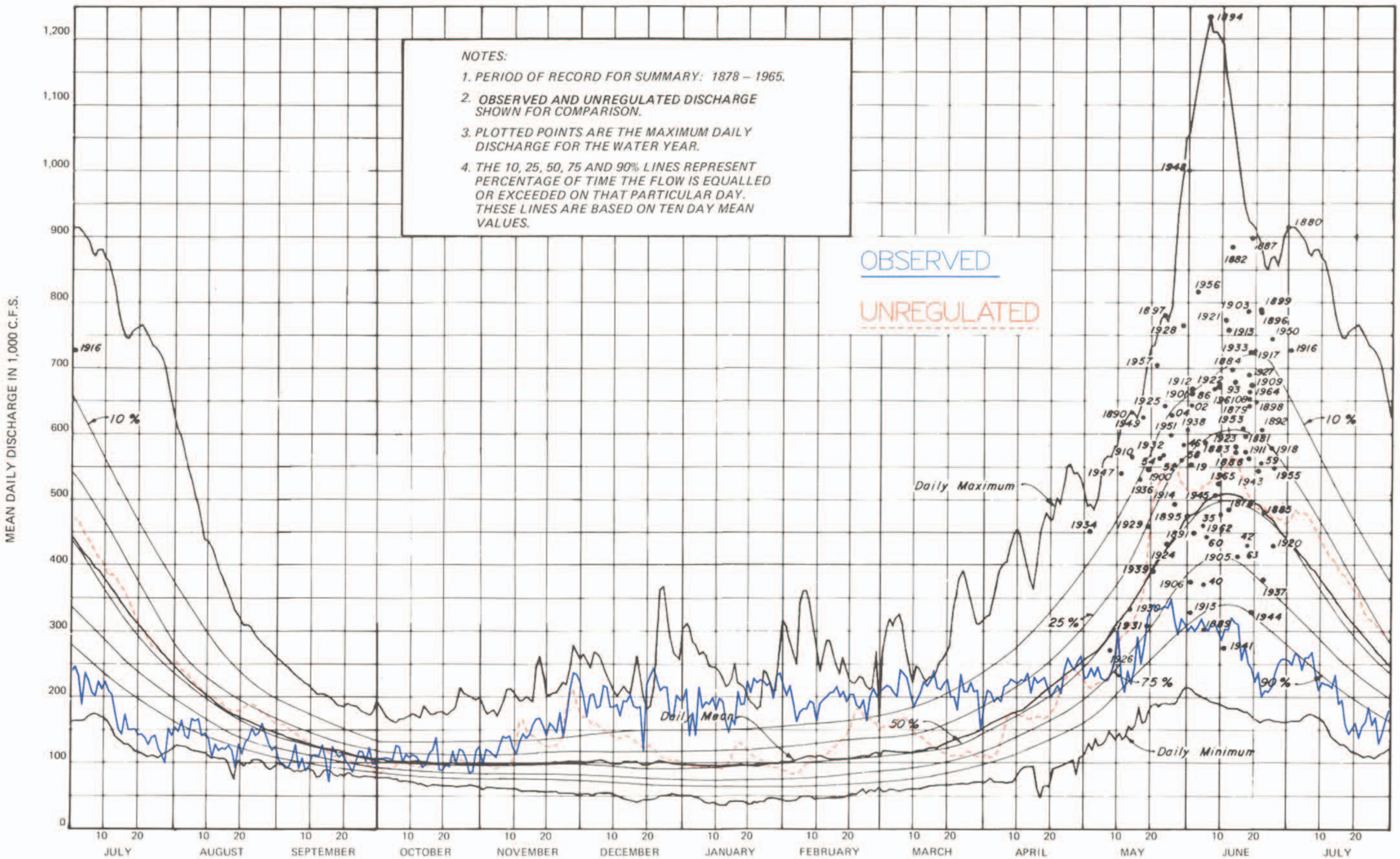
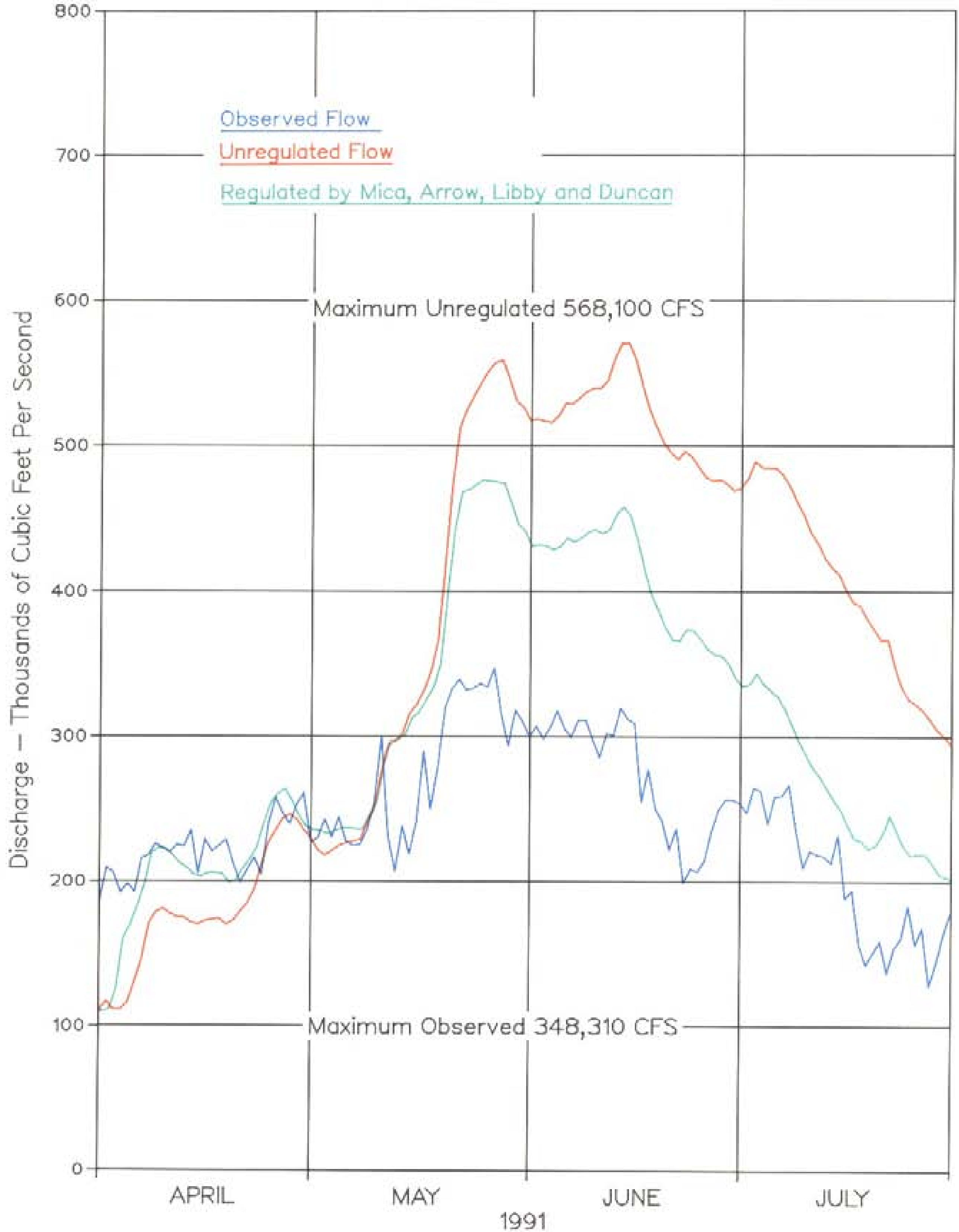


Chart 14
Columbia River at The Dalles
1 April 1991 – 31 July 1991



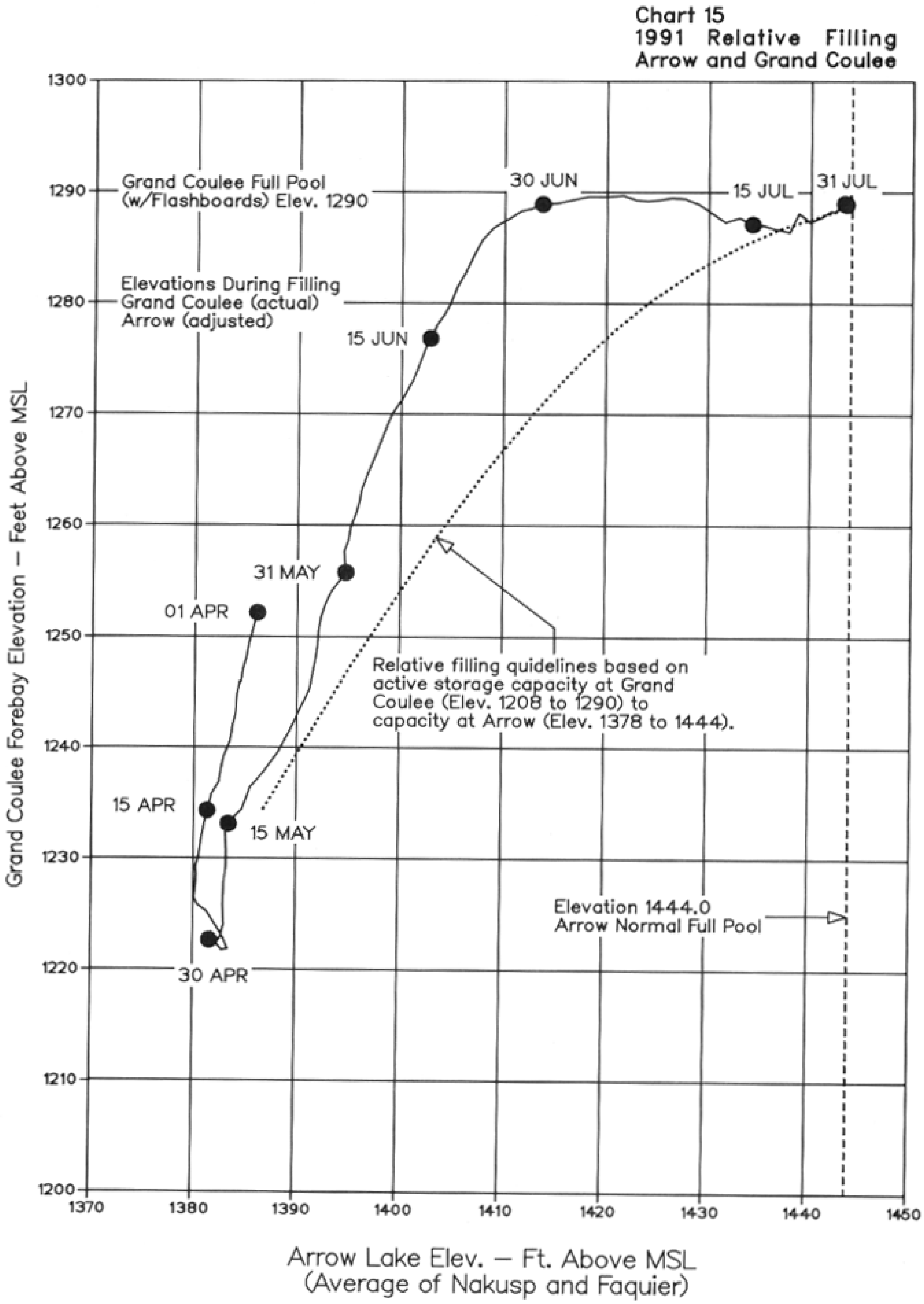


Chart 15
1991 Relative Filling
Arrow and Grand Coulee
Grand Coulee Full Pool
(w/Flashboards) Elev. 1290
Elevations During Filling
Grand Coulee (actual)
Arrow (adjusted)
30 JUN
15 JUL
31 JUL
15 JUN
31 MAY
01 APR
15 APR
15 MAY
30 APR
Relative filling quidelines based on
active storage capacity at Grand
Coulee (Elev. 1208 to 1290) to
capacity at Arrow (Elev. 1378 to 1444).
Elevation 1444.0
Arrow Normal Full Pool
Grand Coulee Forebay Elevation — Feet Above MSL
1300
1290
1280
1270
1260
1250
1240
1230
1220
1210
1200
1370
1380
1390
1400
1410
1420
1430
1440
1450
Arrow Lake Elev. — Ft. Above MSL
(Average of Nakusp and Faquier)