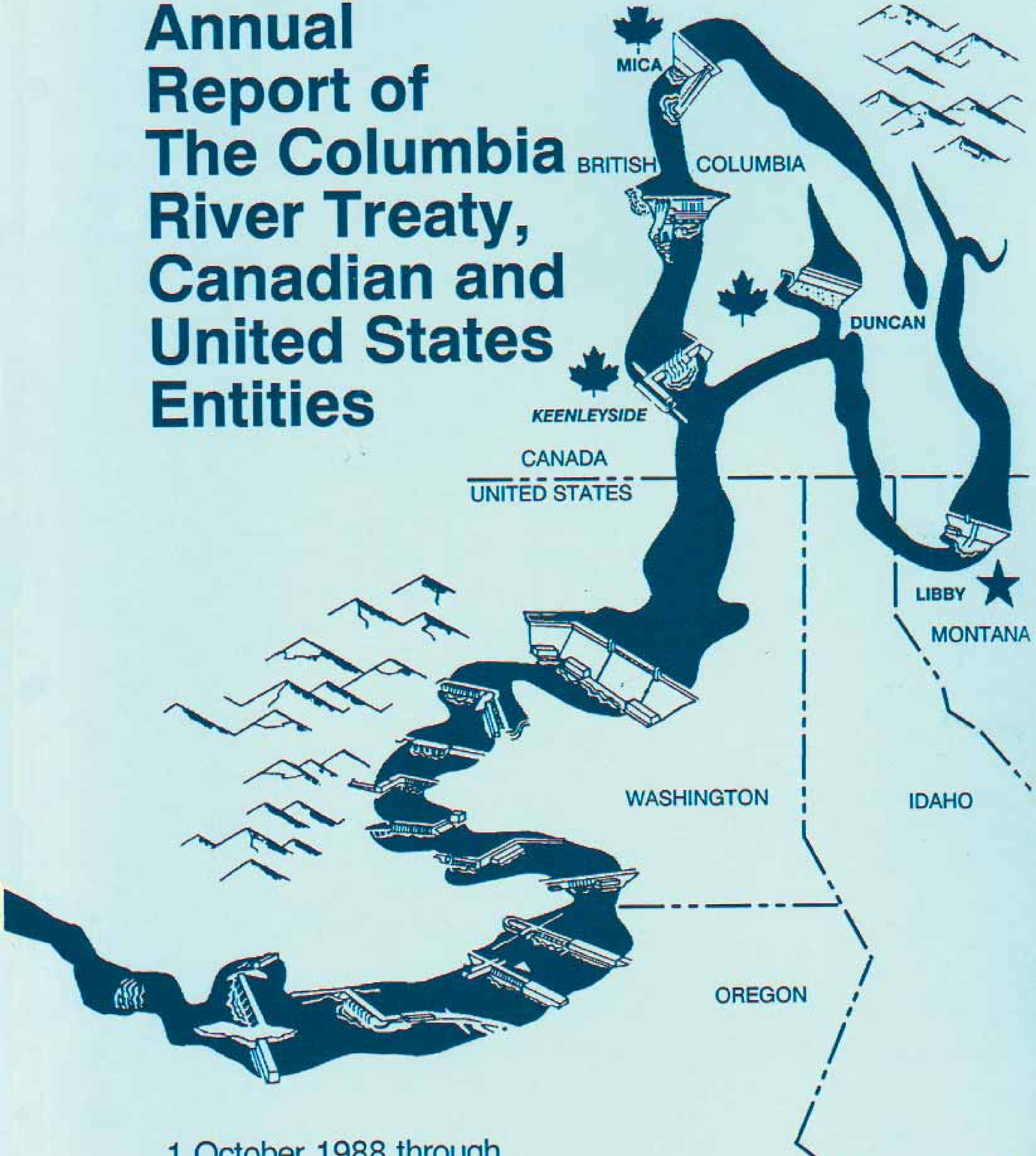
Annual Report of The Columbia River Treaty, Canadian and United States Entities



1 October 1988 through
30 September 1989

November 1989

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

FOR THE PERIOD

1 OCTOBER 1988 - 30 SEPTEMBER 1989

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 1988 through 31 July 1989, dated November 1988.
- Columbia River Treaty Assured Operating Plan and Determination of Downstream Power Benefit studies for Operating Year 1992-93, dated September 1988.
- Columbia River Treaty Assured Operating Plan and Determination of Downstream Power Benefit studies for Operating Year 1993-94, dated September 1989.

System Operation

The coordinated system filled to about 83 percent of capacity by 31 July 1988. Between August and December the system proportionally drafted between third- and fourth- year rule curves. Autumn was much drier than normal and slightly less than normal snowpack accumulation occurred throughout the winter months.

The 1 January water supply forecast for the Columbia River at The Dalles was 101 MAF, or 93 percent of average. Subsequent forecasts through June showed little change. The actual observed runoff 90.6 MAF or 83 percent of average. The large forecast error was attributed to dry soil moisture conditions prior to the snow accumulation period, below average springtime precipitation and cool springtime weather causing increased seepage losses.

The peak daily average flow observed at The Dalles was 312,000 cfs. The river was not regulated on a daily basis for flood control anytime this year. The system storage content reached 88 percent of capacity on 31 July, allowing second year Firm Load Carrying Capability to be adopted under the PNCA for the 1989-90 operating year.

Generation at downstream projects in the United States, delivered under the Canadian Entitlement Exchange Agreement, was 368 average megawatts at rates up to 1052 megawatts. All CSPE power was used to meet Pacific Northwest loads.

Project Operation

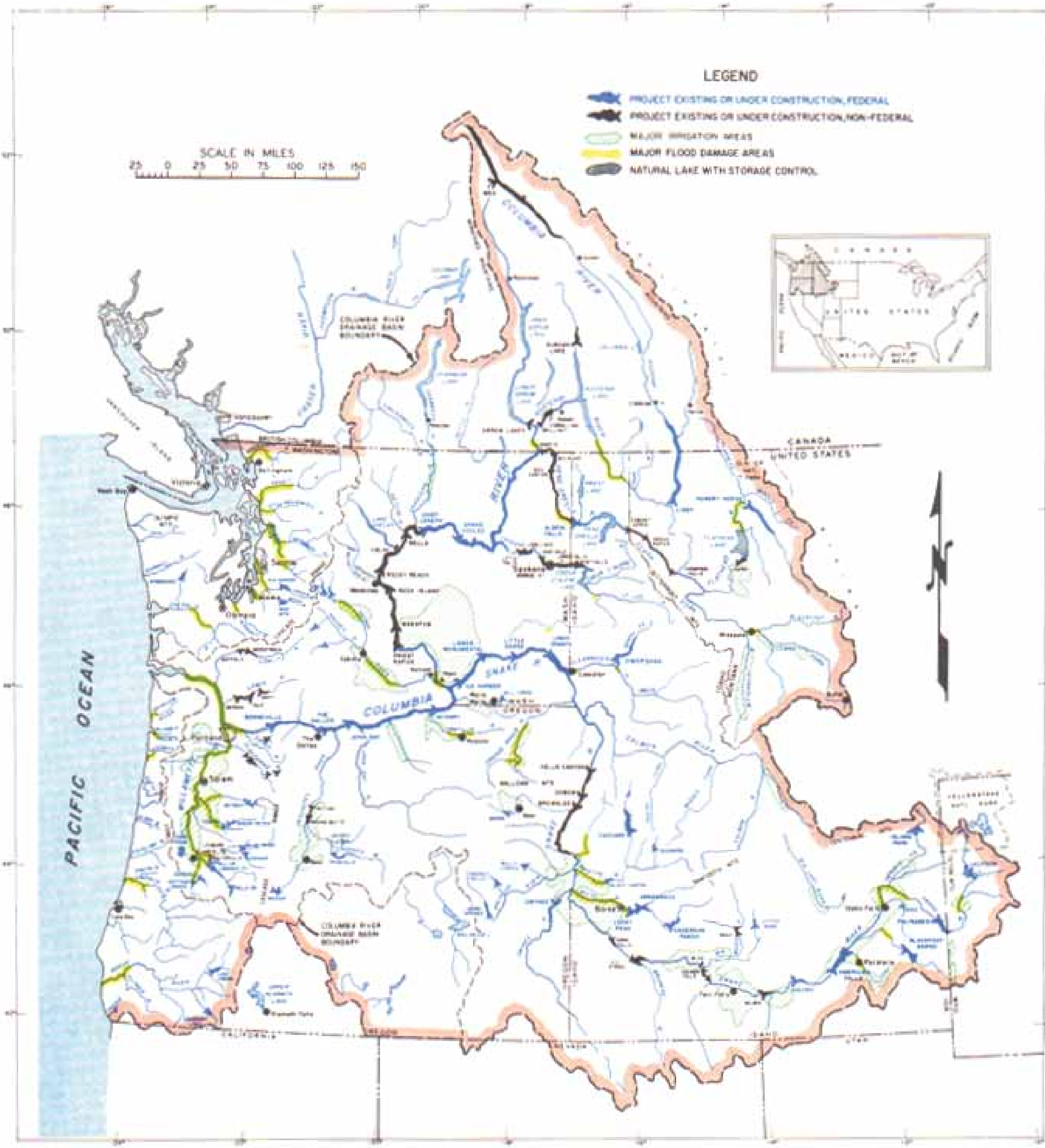
Mica treaty storage reached full content on 10 August 1988. The reservoir reached its lowest level, 2345.2 feet on 13 April 1989. The was the lowest level since the project's initial fill. Full treaty storage content was again reached on 10 September 1989. The maximum level for the operating year, 2454.6 feet, was reached on 18 September.

During the 1988 operating year, Arrow reached its maximum level of 1439.2 feet on 31 July 1988. Although treaty storage was not completely refilled in 1988, some non-treaty storage was transferred from Mica to Arrow to hold Arrow up for recreation. The reservoir drafted throughout autumn and winter, reaching elevation 1387.6 feet on 5 March. The maximum level for the 1989 operating year, 1442.9 feet, was reached on 24 August.

Duncan reservoir completely filled during the 1988 operating year but was drawn down about ten feet by 31 August 1988. The reservoir reached its lowest level during the operating year, 1795.3 feet, on 10 April 1989. The reservoir reached full pool, elevation 1892.0 feet, on 27 July and remained close to full through August.

During the 1988 operating year, Libby reservoir reached a maximum elevation of 2441.5 feet on 24 August 1988. The reservoir was drawn down rapidly throughout the autumn months and more moderately during the wintertime. A minimum level of 2321.2 feet was reached on 9 March. The reservoir reached a maximum level of 2452.6 feet on 31 July and drafted about ten feet in August. This was the first time in Libby's history that the reservoir failed to completely refill in two successive years.

COLUMBIA RIVER AND COASTAL BASINS



1989 Report of The Columbia River Treaty Entities
Contents

1989 Report of The Columbia River Treaty Entities
Contents (continued)

Page

FIGURES

TABLES

CHARTS

I Introduction

This annual Columbia River Treaty Entity Report is for the 1989 Water Year, 1 October 1988 through 30 September 1989. 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 1988 through 31 July 1989. The power and flood control effects downstream in Canada and the United States are described. This report is the twenty-third 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 purpose of increasing hydroelectric power generation, and for flood control in the United States of America and in Canada. 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 1 December 1988 in Vancouver, British Columbia. The members of the two Entities during the period of this report were:

UNITED STATES ENTITY	CANADIAN ENTITY
Mr. James J. Jura, Chairman Administrator, Bonneville Power Administration Department of Energy Portland, Oregon	Mr. Larry I. Bell, Chairman Chairman, British Columbia Hydro and Power Authority Vancouver, B.C.
Brigadier General Pat M. Stevens IV Division Engineer North Pacific Division Army Corps of Engineers Portland, Oregon	

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	CANADIAN ENTITY REPRESENTATIVE
Edward W. Sienkiewicz, Coordinator Senior Asst. Administrator for Power Management Bonneville Power Administration Portland, Oregon	Douglas R. Forrest, Manager Canadian Entity Services B.C. Power Export Corporation Vancouver, B.C.
Robert P. Flanagan, Coordinator Chief, Engineering Division North Pacific Division Army Corps of Engineers Portland, Oregon	
John M. Hyde, Secretary Chief, Seasonal Planning Section Division of Power Supply Bonneville Power Administration Portland, Oregon	

Entity 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	Lawrence E. Nelson, BCH

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

Date	Location	Attendees
15 November 1988	Vancouver, B.C.	13
26 January 1989	Portland, Oregon	15
15 March 1989	Vancouver, B.C.	14
9 May 1989	Portland, Oregon	21
19 July 1989	Vancouver, B.C.	12
12 September 1989	Vancouver, Washington	16

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 1988-89 Detailed Operating Plan (DOP), the 1992-93 Assured Operating Plan and Determination of Downstream Power Benefits (DDPB) and the 1993-94 Assured Operating Plan and DDPB.

Entity 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
Mark W. Maher, BPA, Co-Chairman	William Chin, BCH, Chairman
Douglas D. Speers, ACE, Co-Chairman	John R. Gordon, BCH, Member

Mr. Chin was appointed to succeed Mr. H. Walk on 3 July 1989. There was one meeting of the Hydrometeorological Committee on 12 October 1988 at Burnaby Mountain near Vancouver. The committee reviewed the 1988 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
Lloyd A. Duscha, Chairman, Washington, D.C. Ronald H. Wilkerson, Member Tulsa, Oklahoma	G.M. MacNabb, Chairman Ottawa, Ontario Doug H. Horswill Victoria, B.C.
Herbert H. Kennon, Alternate Washington, D.C. Thomas L. Weaver, Alternate Golden, Colorado S.A. Zanganeh, Secretary Washington, D.C.	Don A. Kasianchuk Victoria, B.C. E.M. Clark, Alternate & Secretary Vancouver, B.C.

Mr. Horswill was appointed to succeed Mr. R. Dolan on 26 April 1989. 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 Permanent Engineering Board and the Entities was held on the afternoon of 1 December 1988 in Vancouver, British Columbia.

PEB Engineering Committee

The PEB has established a PEB Engineering Committee (PEBCOM) to assist in carrying out its duties. The members of PEBCOM are presently:

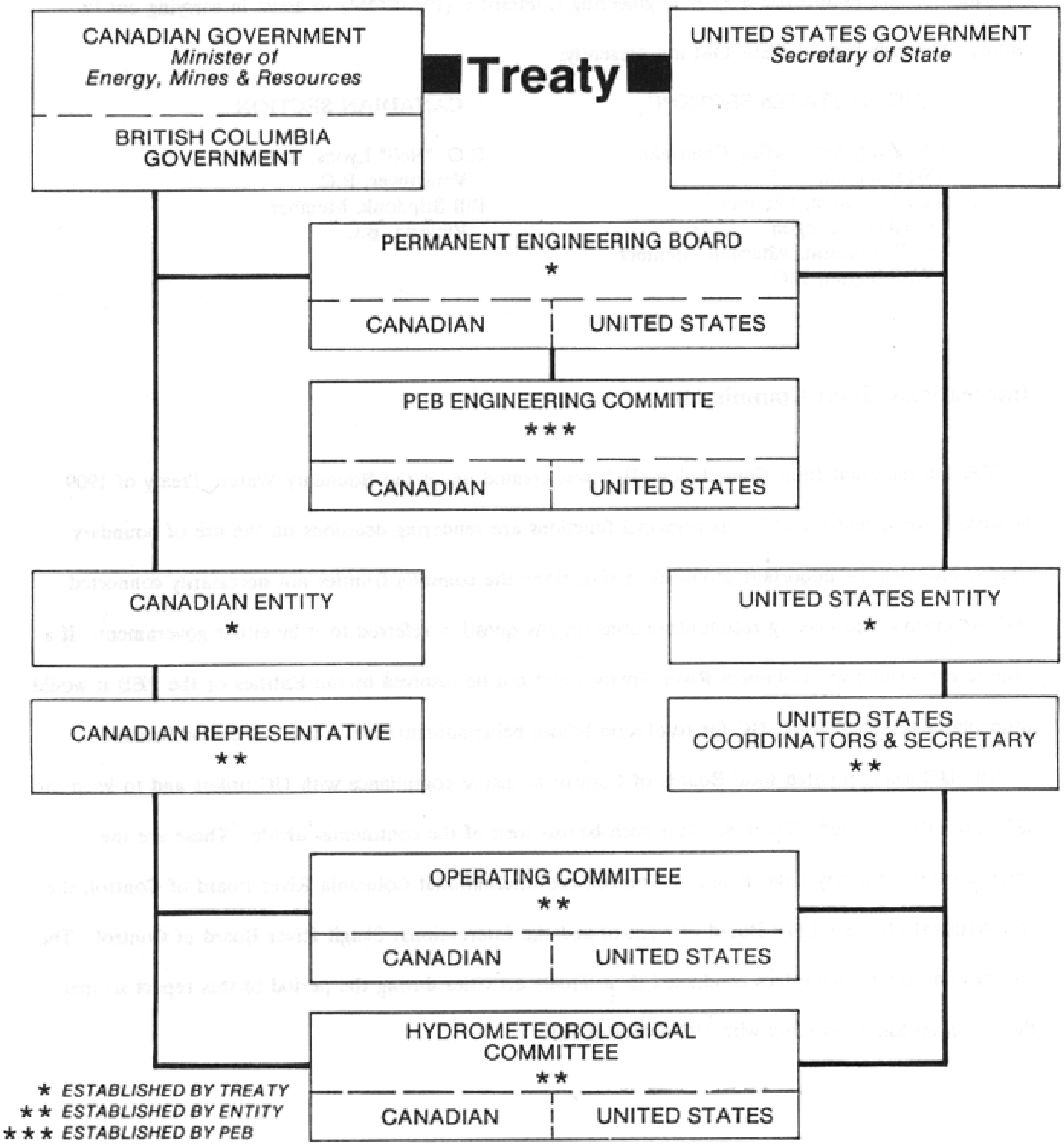
UNITED STATES SECTION	CANADIAN SECTION
S.A. Zanganeh, Acting Chairman Washington, D.C. Gary L. Fuqua, Member Portland, Oregon Lee F. Johnson, Alternate Member Washington, D.C.	R.O. "Neil" Lyons, Chairman Vancouver, B.C. Bill Stipdonk, Member Victoria, B.C.

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 would probably 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 1988 through July 1989.

Assured Operating Plan

The Assured Operating Plan (AOP) dated October 1983 established Operating Rule Curves for Duncan, Arrow and Mica during the 1988-89 operating year. The Operating Rule Curves provided guidelines for refill levels as well as draft levels. 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 1988-89 and 1989-90 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 2.8 average megawatts of energy during the period 1 August 1988 through 31 March 1989, and 3.4 average megawatts of energy during the period from 1 April through 31 July 1989. 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 1988-89 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 November 1988. The DOP established criteria for determining the Operating Rule Curves for use in actual operations. Except for one minor change at Arrow, the DOP used the AOP critical rule curves for Canadian Projects. The Canadian Entity agreed to raise the Arrow first-year critical rule curve in April to improve the hydroregulation in the 1988-89 Pacific Northwest Coordination Agreement operating plan. The Variable Refill Curves and flood control requirements subsequent to 1 January 1989 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. During the period of this report the AOP and DDPB for both 1992-93 and 1993-94 were signed. The following tabulation indicates the date each of these were signed or approved and gives a description of the agreement:

Date Agreement Signed by Entities	Description
1 December 1988	Detailed Operating Plan for Columbia River Treaty Storage, 1 August 1988 through 31 July 1989, dated November 1988.

14 October 1988	Columbia River Treaty Assured Operating Plan and Determination of Downstream Power Benefit Studies for Operating Year 1992-93, dated September 1988.
1 September 1989	Columbia River Treaty Assured Operating Plan and Determination of Downstream Power Benefit Studies for Operating Year 1993-94, dated September 1989.

Long Term Non-Treaty Storage Contract

In accordance with the 9 April 1984 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 the Agreement 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 1988 through 31 March 1989. 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 1989. Indices of temperature and precipitation in the Columbia Basin for the winter and snowmelt seasons are shown on Charts 3 and 4. Chart 5 illustrates temperature and precipitation indices for Canada during the snowmelt season. The following paragraphs describe significant weather events between 1 August 1988 and 30 September 1989.

Weather during the 1988-89 operating year was near average with respect to both temperature and precipitation, with some deviations from this generalization. August 1988 was very dry with only the precipitation index for the Columbia Basin above Castlegar, BC being above average. During September and October 1988 high pressure dominated Columbia Basin weather conditions, and the storm track was directed toward the Washington Cascades and into British Columbia. As a result, precipitation in the North Cascades and the Columbia Basin above Grand Coulee was 115 to 120 percent of normal while the Snake River Basin received only 25 to 36 percent.

The snow accumulation season began in November with the entrenchment of the Aleutian low pressure system in the Gulf of Alaska. This resulted in the storm track moving from the southwest, causing above normal precipitation in virtually the entire Pacific Northwest. Most of the precipitation above 5,000 ft fell as snow. Precipitation varied from 134 to 209 percent of normal. By the end of the month the general weather pattern began to change and an upper air ridge formed on the coast, cutting off the supply of moisture.

During the first 12 days of December the high pressure ridge produced only light precipitation and showers. This ridge was then replaced by a weak trough which lasted three weeks into January. Before month's end it produced nine storms that entered the Washington and Oregon coasts. These storms had little southerly component so they contained only a modest amount of moisture and were unable to make up the precipitation deficit from the first part of the month. Although the basin as a whole received normal or slightly below normal precipitation during January, an area along the 45th parallel plus the northern part of the Columbia Basin received above normal precipitation.

In early February the Aleutian low moved to the Oregon-Nevada border and a stationary Arctic high pressure system built just off the southeastern coast of Alaska. During the following two weeks extremely cold Arctic air was directed by these systems into the Pacific Northwest, dropping temperatures to more than 30°F below normal. Many minimum temperature records were set: Boise set a new mean monthly low temperature for February and Portland had the second coldest February on record. This cold weather not only produced no precipitation but also reduced the base runoff that typically occurs during the winter. By mid-month the Aleutian low had reestablished itself and the weather became more seasonal, with short periods of moderate precipitation followed by a few dry days. On 16 February heavy rains struck the northern Oregon coast but did not extend beyond the Cascade Mountains. The snow accumulation season concluded in March with a low pressure system deepening in the Gulf of Alaska and sending a series of weak frontal waves into the Washington and British Columbia coasts. March precipitation indices were 128 percent of normal at Grand Coulee and 85 percent of normal for the Snake Basin. A brief warm spell in early March resulted in snow melt from low elevation basins.

The snow melt season began in April with light rains produced by a westerly flow from an off-shore low pressure trough. This trough began to retrograde into the central Pacific as a high pressure ridge began building on the coast, directing the flow of warm, moist air into British Columbia. By the 8th the temperatures had risen to more than 10°F above normal, starting another snow melt episode. By the 19th a low pressure system established itself off the Oregon coast and began routing moisture into the area west of the Cascades. The Snake Basin remained dry most of the latter part of the month, averaging only 61 percent of normal while the basin above Grand Coulee averaged 110 percent.

The first 10 days of May provided another warm spell that induced additional snow melt. But by the 12th the weather patterns had again changed so that cool westerly weather entered the region, producing below normal temperatures, light rain, and scattered instability showers. During the last week of May the low moved inland over Washington and combined its moist air with cold air from Canada to deposit 6 inches of snow in the Cascades on May 28. The snow spread into Idaho and Montana on the following day, with 10 inches of snow falling in Glacier Park. Despite this heavy snowfall, May precipitation for Columbia Basin above Grand Coulee averaged only 117 percent of normal and the Snake Basin only 102 percent.

During the first twelve days of June a flat ridge on the Washington-Oregon coast dominated the weather. It provided temperatures up to 15°F above normal and virtually no precipitation to the upper Columbia. Meanwhile, a low pressure system was deepening in the Gulf of Alaska. As this system moved closer to the Pacific Northwest coast the upper air winds shifted to the south-southwest and brought moist unstable air into the region. Two storms, one on the 16th and the other on the 18th provided most of the month's precipitation. June ended with a shallow low pressure system in the Gulf of Alaska sending weak impulses of moisture into the Northwest. In summary, weather throughout the snowmelt period was cool and lacked any sustained warm period.

July set the tone for a summer season that was closer to normal than what was experienced the past few years. The low pressure system moved to near Vancouver Island where it remained for 12 days, producing normal temperatures and only minor rainfall. The next week saw an intensifying of the low that brought significant rainfall to the westside stations. Some of this moisture made it east of the Cascades where a few isolated thundershowers resulted and monthly precipitation totaled over 100 percent. The remainder of the month had unsettled weather which was cloudy and mild in the west and hot and dry east of the Cascades. August weather was dictated by a series of three low pressure systems that successively passed through the basin along the US-Canadian border. The first produced below normal temperatures and very little rainfall. The second had normal temperatures and rainfall, while the third brought unseasonable low temperatures and high precipitation. The Columbia Basin above Grand Coulee, Willamette, Umatilla, John Day, Pend Oreille-Spokane, Flathead, Kootenai, Southeastern Washington, and Burnt-Grande Ronde subbasins all reported well in excess of 200 percent of normal precipitation with the latter two reporting more than 300 percent. The first half of September was generally dry with only the Columbia Basin above Castlegar, Kootenai, Flathead and Okanogan Basins receiving more than normal precipitation.

The preliminary and final monthly precipitation indices for the Columbia Basin above The Dalles are shown on the following page. The final precipitation figures differ from the preliminary figures because the preliminary index is computed based on 16 usually representative stations. The final index is based on 60 stations and is computed at the end of each month after all the data are collected. The following tabulation shows the 25-year average (1961-1985) monthly precipitation in the Columbia Basin above The Dalles as compared to the final and the preliminary indices for Water Year 1989.

25-year WY 89 Indices			
Month	Average (in.)	Final (%)	Prelim (%)
Oct 88	1.75	59	48
Nov 88	2.78	159	154
Dec 88	3.35	59	61
Jan 89	3.10	97	91
Feb 89	2.19	61	67
Mar 89	1.93	169	138

25-year WY 89 Indices			
Month	Average (in.)	Final (%)	Prelim (%)
Apr 89	1.65	90	98
May 89	1.80	112	123
Jun 89	1.93	67	65
Jul 89	1.06	81	95
Aug 89	1.27	176	185
Sep 89	1.51	60	60

STREAMFLOW

The observed inflow and outflow hydrographs for the Treaty reservoirs for the period 1 July 1988 through 31 July 1989 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 1989 period including a plot of flows occurring if regulated only by the Treaty reservoirs. The following paragraphs describe significant streamflow events from the summer of 1988 through September 1989.

Streamflows in the basin above The Dalles were below normal for most of the operating year. Only March, April, and May exceeded the norm. The low flows were a direct reflection of the dry soil moisture conditions as the precipitation for the basin was near normal for the operating year. The peak regulated discharge for the Columbia River at the Dalles was 312,000 cfs.

The 1988-89 monthly modified streamflows and the average monthly flows for the 1929-78 period are shown in the following table for the Columbia River at Grand Coulee and at The Dalles. These modified flows have been corrected for storage in lakes and reservoirs to exclude the effects of regulation, and are adjusted to the 1980 level of development for irrigation.

	Columbia River at Grand Coulee in cfs		Columbia River at The Dalles in cfs	
Time Period	Modified Flow 1988-1989	Average 1929-1978	Modified Flow 1988-1989	Average 1929-1978
Aug 88	75,120	103,142	93,170	139,054
Sep 88	46,440	64,457	65,230	97,214
Oct 88	47,290	50,650	74,120	87,349
Nov 88	45,050	45,525	80,370	89,536
Dec 88	30,620	42,793	65,950	95,166
Jan 89	30,300	38,482	63,500	91,901
Feb 89	22,270	41,045	60,500	102,817
Mar 89	46,990	50,359	145,400	122,728
Apr 89	140,380	117,432	262,700	221,814
May 89	245,240	272,024	436,000	421,758
Jun 89	275,940	325,692	379,100	479,654
Jul 89	141,690	195,586	192,600	216,610
YEAR	95,870	112,678	160,300	180,649

Seasonal Runoff Forecasts and Volumes

Observed 1989 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	5,570	86
Duncan Reservoir Inflow	1,840	89
Mica Reservoir Inflow	10,670	92
Arrow Reservoir Inflow	21,030	80
Columbia River at Birchbank	36,870	90
Grand Coulee Reservoir Inflow	54,380	87
Snake River at Lower Granite Dam	19,000	79
Columbia River at The Dalles	81,940	85

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 1989 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 1989 forecast of January through July runoff for the Columbia River above The Dalles was 99.5 MAF and the actual observed runoff was 90.6 MAF, a ten percent differential. 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	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	84.7	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

V Reservoir Operation

General

The 1988-89 operating year was characterized by dry autumn conditions, slightly less than normal snowpack accumulation in the winter months and markedly less spring runoff than forecasted. At The Dalles, the observed January-July runoff was about 83 percent of average and ten percent less than forecast on 1 April. Although the observed runoff was significantly more than in the prior two consecutive drought years, 1989 was still much lower than average and is the fourth year of below average runoff for the Columbia River at The Dalles in the past five years.

The operating year began with the coordinated reservoir system officially filled to about 83 percent of capacity on 31 July 1988. As a result, third year firm energy load carrying capability was adopted for the 1988-89 operating year. Third-year FELCC turned out to be slightly greater than second-year would have been if it were adopted.

Between August and December the system operated in accordance with proportional draft requirements, with draft levels between third- and fourth-year critical rule curves.

The 1 January water supply forecast was 101 MAF, or 93 percent of the 1961-85 average, with subsequent forecasts through April showing little change. As a result of the close-to-average forecasted water supply, no proportional draft was necessary in the wintertime to meet firm power requirements.

Weather throughout the spring snowmelt period was generally cool with no sustained hot spells. Consequently, the reservoir system was not operated on a daily basis for flood control anytime during the 1989 runoff. The year's observed peak flow at The Dalles of 312,000 cfs occurred on 4 May. Water budget flows were released from Grand Coulee between 22 May and 15 June.

By 31 July, the coordinated system reached 87.6 percent of its full capacity, resulting in the adoption of second-year FELCC for the 1989-90 operating year. This FELCC level is similar to first-year FELCC because delays in the 1988-89 coordination agreement planning (in the spring of 1988), coupled with the utilities' knowledge the system would begin the 1988-89 operating year much less than full resulted in a large amount of FELCC being shifted to the second year of the critical period in the 1988-89 Operating Program.

Mica Reservoir

As shown in Chart 6, Mica Reservoir (Kinbasket Lake) was filled to elevation 2441.8 feet by 31 July 1988, or 33 feet below full pool of 2475 feet. The remaining space below full pool was primarily non-Treaty storage, although some Treaty storage was also not filled by 31 July. Mica continued to fill in August and full Treaty storage content was reached on the 10th. During September only Mica non-Treaty storage was drafted. By 30 September, the reservoir was drawn down about 3.5 feet to 2439.2 feet, with the discharge at the project varying between 14,000 cfs and 40,000 cfs during this period.

Treaty storage was drafted beginning in October. Due to the low Treaty storage levels at Arrow, the Mica Treaty storage release was increased above the normal Detailed Operating Plan (DOP) schedule for the period from October until January as specified by the 1988-89 DOP, Mica Project Operating Criteria. This increased the draft rate significantly. By 31 December, the reservoir was drawn down to elevation 2413.3 feet, approximately 20 feet below its Operating Rule Curve after adjusting for the non-Treaty storage.

The draft continued during February and March. From 10 until 23 March, the discharge at Mica was reduced to zero to facilitate drafting of Revelstoke Reservoir, which would permit the Revelstoke project discharge to be reduced to zero outflow during the Revelstoke tailrace dredging work. Treaty storage at Mica was drafted completely by 27 February. B.C.Hydro's non-Treaty storage was then used to maintain the level of discharge as specified in the DOP. About 1.1 maf of this non-Treaty storage was drafted for this purpose and held in Arrow Reservoir. This storage was returned to Mica by 31 May. By 13 April, the reservoir had been drawn down to elevation 2345.2 feet, the lowest level since it was first filled in 1976, and about 20 feet lower than last year's lowest level.

Mica began filling on 14 April. From 14 April until mid-June, the project was generally at zero discharge to accommodate the filling of both Treaty and non-Treaty storage. Despite below normal runoff, the reservoir filled quickly to 2406.4 feet, or ten feet below its Operating Rule Curve after adjusting for non-Treaty storage, by 19 June. Inflow into Mica peaked at 88,850 cfs on 14 June. During July and August, the project outflow was increased to 20,000-25,000 cfs to meet B.C.Hydro's system load and BPA's non-Treaty storage requirements. The reservoir still filled about 40 feet during this period, reaching elevation 2449.3 feet on 31 August. Mica reached its maximum elevation for the operating year, elevation 2454.6 feet, approximately 20 feet below its full pool elevation 2475 feet, on 18 September.

Revelstoke Reservoir

During the past operating year, Revelstoke project was generally operated as a run-of-the-river plant, maintaining the reservoir level within 5 feet of its normal full pool elevation of 1880.0 feet.

During March, the reservoir was drawn down approximately 15 feet below full pool in preparation for a dredging operation in the project tailrace. Beginning 23 March and continuing until June, the outflow was reduced to zero for up to several days at a time to facilitate this operation. The dredging operation is expected to improve the efficiency of the power plant. The reservoir was subsequently refilled to near full pool by 20 June.

Arrow Reservoir

As shown in Chart 7, Arrow was at its highest level of 1988, elevation 1439.2 feet, about five feet below normal full pool of 1444 feet, on 31 July. Treaty storage was filled to elevation 1436.5 feet, with the difference being the transfer of some B.C.Hydro non-Treaty storage from Mica to Arrow. As the runoff receded, Arrow Treaty storage began in early August to meet downstream storage requirements. However, with increased transfer of non-Treaty storage from Mica, Arrow was maintained near elevation 1436.0 feet during August.

From September until mid-November, Arrow was drawn down rapidly as releases from the upstream projects were reduced. Between October and January, the Treaty storage level at Arrow was low enough to trigger increased Treaty storage releases from Mica as specified by the DOP Mica Operating Criteria. The October - November discharge at Arrow varied between 20,000 cfs and 45,000 cfs, except for several days from 22 to 24 October, and from 23 to 26 November, when the project discharge was reduced to 10,000 cfs to accommodate storing of non-Treaty storage at Mica. Increased inflows between mid-November and early December filled the Reservoir about four feet, to 1418.7 feet by 9 December. Arrow resumed drafting on 10 December and continued to draft through January and February. The project outflow was increased to as high as 82,000 cfs during this period. From 4 until 9 February, the discharge at Arrow was 15,000 cfs higher than the Treaty requirement, as additional Treaty storage draft was needed by downstream projects due to the usually cold weather in February. This advanced Treaty storage draft was returned to Arrow by 24 March. On 5 March, Arrow reached its lowest level for the current operating year of 1387.6 feet, approximately 9.5 feet above its minimum level.

Arrow began refilling when the project outflow was reduced to 19,000 cfs on 6 March. On 11 March, the project outflow was further reduced to 9,000 cfs. From 24 to 26 March and also on 1 April, the discharge at Arrow was reduced to 5,000 cfs to accommodate rebuilding of a ferry ramp near Castlegar, B.C. The reservoir reached 1396.3 feet on 31 March. Arrow continued to fill rapidly in May and June. During July, it was recognized that the runoff would be lower than forecasted, and that system storage would not completely refill. Consequently, the discharge at Arrow was adjusted to meet proportional draft requirements. On 31 July, the Arrow reservoir was filled to 1439.7 feet, or approximately four feet below full pool. During August, the proportional draft points allowed Arrow to continue filling slightly and to maintain its level near 1,442 feet. Beginning in July, Detailed Operating Plan critical rule curves were used by the Northwest Power Pool Coordinating Group for developing proportional draft points instead of Assured Operating Plan curves. This reduced draft requirements for the Canadian reservoir system.

Arrow began drafting Treaty storage on 2 September when the project outflow was increased to 37,000 cfs. By 10 September, the reservoir was drafted about two feet to 1440.3 feet.

Duncan Reservoir

As shown in Chart 8, Duncan reservoir reached its full pool elevation of 1892.0 feet on 26 July 1988. The project then discharged inflow, maintaining full pool, until 9 August. To meet the proportional draft requirement, the discharge was then increased to 10,000 cfs beginning 10 August. This drafted the reservoir to 1881.8 feet by 31 August.

During the period 10 September to 23 October, the project was reduced to minimum discharge of 100 cfs to reduce spill at power plants on the Kootenay River. From 24 to 31 October, Duncan discharged up to 8,000 cfs to maintain sufficient flow through the Kootenay River projects while the Libby outflow was curtailed. Duncan resumed discharging 100 cfs on 1 November and filled to 1890.1 feet on 24 November.

Between December and February, the project was drafted to meet its flood control drawdown requirement. The discharge was maintained at 8,000 cfs during this period, drafting the reservoir to 1805.4 feet, slightly below its flood control requirement of 1807.8 feet, by 28 February. Duncan continued to draft during March and early April. On 10 April, the reservoir reached elevation 1795.3 feet, approximately one foot above its minimum level 1794.2 feet.

Duncan began filling on 11 April when its outflow was reduced to 100 cfs. On 30 April, the reservoir reached elevation 1806.3 feet, or three feet higher than the Operating Rule Curve. In response to changing weather patterns, the runoff into Duncan reservoir varied between well above normal and well below normal during May and June. The daily average inflow peaked at 20,790 cfs on 15 June. During this period, the reservoir filled rapidly, reaching 1869.9 feet on 30 June.

Beginning 22 July, the project outflow was gradually increased to match inflow. The reservoir reached full pool of 1892.0 feet on 27 July. Duncan then discharged inflow until 2 September when the project outflow was increased to 6,000 cfs to help fill Kootenay Lake. By 10 September, the reservoir was drawn down two feet to 1889.9 feet.

Libby Reservoir

Libby did not completely refill during the 1988 spring runoff. Lake Koocanusa reached its maximum level of 2441.5 feet, 17.5 feet from full, on 24 August. Two feet of drawdown occurred between this date and Labor Day to meet firm power requirements.

After Labor Day the reservoir was drafted more rapidly with outflows for the September-December period averaging 16,700 cfs. During this time, the coordinated system was proportionally drafted between third- and fourth-year critical rule curves. By 31 December, Lake Koocanusa was at elevation 2353.5 feet, its lowest elevation for this date since the project was constructed.

In January, the Columbia system water supply forecasts were sufficient enough that no additional proportional draft was necessary at Libby for meeting firm loads. Consequently, Libby's operating rule curve for January was based on the project discharging its minimum flow of 3000 cfs for the entire month. Actual releases for the month were 4000 cfs for all but nine days when they were increased to about 20,000 cfs. As a result of this nine-day operation, Lake Koocanusa drafted about ten feet below its operating rule curve to elevation 2338.9 feet on 31 January. This overdraft occurred to partially offset draft requirements at Hungry Horse, which had a much lower refill probability based on 1 January water supply forecasts. Dworshak was drafted as well to help reduce the Hungry Horse draft requirement.

During the first week in February, an arctic airmass centered over the Pacific Northwest resulted in some of the coldest winter weather on record. Consequently, all available generating resources in the region, including Libby, were increased to help meet record regional power requirements. Libby discharged 20,000 cfs during this period before being reduced to 4000 cfs on 10 February and finally to 3000 cfs on 23 February. As a result of this operation Libby fell to approximately 24 feet below its operating rule curve and was at elevation 2322.6 feet on 28 February. A brief cold spell in early March resulted in some additional generation at Libby with the outflow again being reduced to 3000 cfs on 4 March. Lake Koocanusa reached its lowest elevation for the year, 2321.2 feet, on 9 March.

Inflows to Lake Koocanusa began rising in mid-April and the seasonal peak of 49,100 cfs occurred on 8 June. Despite the overdraft of Libby in the winter, springtime water supply forecasts indicated a favorable refill probability. On 21 June, the outflow was increased to 4000 cfs as the lake was about 27 feet from full and filling over 1 foot per day and had almost a 95 percent refill probability based on

4000 cfs minimum discharge. In late June, however, snow surveys indicated the Kootenai basin water supply was considerably less than previously forecasted, consequently Libby discharge was reduced back to 3000 cfs. In early July, deteriorating water supply conditions throughout the entire Columbia basin resulted in a return to proportional draft operations to meet firm load requirements. Libby discharged 3000 cfs until 20 July when the outflow was increased to about 10,000 cfs. Lake Koocanusa reached its maximum elevation for the operating year, 2452.6 feet and about six feet from full on 31 July 1989. The reservoir began drafting in August and by Labor Day was at elevation 2442.8 feet. The January-July observed runoff was 5913 kaf, 91 percent of the 1961-85 average, and 380 kaf less than the 1 June forecast. This error is equivalent to the top 8.5 feet in Lake Koocanusa.

Kootenay Lake

As shown in Chart 10, Kootenay Lake passed inflow during July and August 1988, maintaining the lake level about 1743.0 feet. On 1 September, the discharge was reduced to prevent spill at the Brilliant plant on the Kootenay River. The reservoir filled slowly and reached 1745.1 feet on 15 October, sligthly below the International Joint Commision Rule Curve elevation of 1745.32 feet. During November and December, Kootenay Lake operated between elevations 1744.5 feet and 1745.0 feet with its discharge varying between 14,000 cfs and 32,000 cfs. Between January and March, Kootenay Lake was drafted in accordance with its IJC Rule Curve. On 6 April, the reservoir was drawn down to its lowest level for the current operating year, 1739.0 feet.

Inflow into Kootenay Lake increased about mid-April and the reservoir began to fill. By 24 April, the lake had filled about 2.5 feet to elevation 1741.3 feet. From 25 April until 1 May, the reservoir remained near 1741.5 feet. The reservoir continued to fill in May, reaching elevation 1745.5 feet on 13 May before being drafted about one foot, to elevation 1744.3 feet, by 31 May due to below normal runoff during this period. The reservoir again resumed filling on 1 June and the level peaked at 1746.8 feet on 15 June. Discharge from Kootenay Lake was as high as 50,000 cfs during this period. As the runoff receded, the reservoir level dropped rapidly, reaching elevation 1743.3 feet at Nelson on 3 July. Inflow was then released, maintaining the reservoir at about 1743.0 feet through July and August.

Beginning 1 September, the Kootenay Lake discharge was again reduced to prevent spill at the Brilliant plant. The reservoir filled to 1744.8 feet by 10 September before the discharge was increased to pass inflow.

VI Power and Flood Control Accomplishments

General

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

1. "Detailed Operating Plan for Columbia River Treaty Storage - 1 August 1988 through 31 July 1989," dated November 1988.

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 1988-89 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 1988-89 Assured Operating Plan, prepared in 1983, was used as the basis for the preparation of the 1988-89 Detailed Operating Plan.

Power

The Canadian Entitlement to downstream power benefits from Duncan, Arrow and Mica for the 1988-89 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 368 average megawatts at rates up to 1,052 megawatts, from 1 August 1988, through 31 March 1989, and 349 average megawatts, at rates up to 1,017 megawatts, from 1 April 1989, through 31 July 1989. All CSPE power was used to meet Pacific Northwest loads.

The Coordinated System reservoirs filled to only 83 percent of full by 1 August, 1988, and after being drawn down during the 1988-89 operating year, refilled to only 88 percent of full on 31 July 1989. This is the first time that the Coordinated System failed to refill two years in a row. The following table shows composite storage draft for Coordinated System reservoirs at the end of each month compared to operating rule curves during the 1988-89 operating year. Normal full Coordinated System reservoir storage is approximately 63,000 megawatt-months. All figures are 1000 MWMo.

Month	Operating Rule Curve	Actual	Difference
Aug 88	0.5	12.5	-12.0
Sep 88	3.5	17.5	-14.0
Oct 88	7.0	22.0	-15.0
Nov 88	11.5	25.0	-13.5
Dec 88	18.0	35.5	-17.5
Jan 89	31.0	45.0	-14.0
Feb 89	37.0	51.0	-14.0
Mar 89	39.0	53.5	-14.5
Apr 89	40.0	46.0	- 6.0
May 89	30.0	33.5	- 3.5
Jun 89	10.0	15.0	- 5.0
Jul 89	0.5	7.5	- 7.0

During the January-June period of 1989, volume runoff forecasts for cyclic reservoirs were suffcient to cause the VECC to be lower than the base energy content curves, resulting in no proportional draft being necessary during this period.

The following table shows BPA nonfirm and surplus firm sales in megawatt-hours to northwest and southwest utilities during the 1988-89 operating year.

Period	To Northwest Utilities		To Southwest Utilities	
	Nonfirm	Surplus Firm	Nonfirm	Surplus Firm
Aug 88	0	9,200	0	44,145
Sep 88	0	52,660	0	385,899
Oct 88	0	46,935	0	381,246
Nov 88	0	155,493	0	354,174
Dec 88	0	157,347	0	368,151
Jan 89	0	111,600	0	10,836
Feb 89	0	100,800	0	5,364
Mar 89	0	11,600	6,420	10,853
Apr 89	232,152	34,068	804,907	12,300
May 89	835,411	33,384	1,425,773	20,095
Jun 89	268,743	39,280	760,404	36,914
Jul 89	0	43,544	0	142,699
TOTAL	1,336,306	895,911	2,997,504	1,772,676

Flood Control

The Columbia River Basin reservoir system, including the Columbia River Treaty projects, was not operated on a daily basis for flood control anytime during 1989. This is the fifth year in a row in which daily operation for flood control during the spring runoff has not been necessary. Flood control during the 1989 runoff was provided by the normal refill operation of the Treaty reservoirs and other storage reservoirs in the Columbia River Basin. The observed and unregulated hydrographs for the Columbia River at The Dalles between 1 July 1989 and 31 July 1989 are shown on Chart 14. The unregulated peak flow at The Dalles would have been 513,000 cfs on 12 May 1989 and it was controlled to a maximum of 312,000 cfs on 4 May 1989.

The observed peak stage at Vancouver, Washington was 10.1 feet on 5 May 1989 and the unregulated stage would have been 18.8 feet on 13 May 1989. 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.

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 were 330,000 on 1 January 1989, 340,000 cfs on 1 February, 315,000 cfs on 1 March, 333,000 cfs on 1 April and 367,000 cfs on 1 May. Data for the 1 May ICF computation are given in Table 6.

Table 1
Unregulated Runoff Volume Forecasts
Millions of Acre-Feet
1989

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	2.0	23.2	11.1	6.3	89.4
February	2.0	23.3	11.4	6.2	92.1
March	2.0	22.3	11.0	5.6	87.1
April	2.0	22.2	11.1	6.2	91.4
May	2.0	22.5	11.1	6.3	90.4
June	1.9	22.0	10.6	6.4	88.5
Actual	1.8	21.0	10.7	5.6	81.9

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 1989

	INITIAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1 PROBABLE FEB 1 - JUL 31 INFLOW, KSFD[1]		4539.5	4716.1	4595.6	4608.7	4609.8	4463.6
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] ..		3955.0	4235.6	4151.5	4194.3	4228.9	4084.8
4 OBSERVED FEB 1 - DATE INFLOW, KSFD		0.0	0.0	119.0	222.0	458.7	1299.1
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD[3]		3955.0	4235.6	4032.5	3972.3	3770.2	2785.7
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME ..		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD[4]		3955.0					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		2180.0					
MIN. JAN 31 RESERVOIR CONTENT, KSFD[5]		1754.2					
MIN. JAN 31 RESERVOIR ELEVATION, FT[6]		2434.5					
JAN 31 ECC, FT[7]		2432.2					
BASE ECC, FT	2432.2						
LOWER LIMIT, FT	2401.6						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME ..		97.8	97.9				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD[4]		3868.0	4142.4				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		1760.0	1760.0				
MIN. FEB 28 RESERVOIR CONTENT, KSFD[5]		1421.2	1146.8				
MIN. FEB 28 RESERVOIR ELEVATION, FT[6]		2427.3	2421.3				
FEB 28 ECC, FT[7]		2419.8	2419.8				
BASE ECC, FT	2419.8						
LOWER LIMIT, FT	2394.1						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME ..		95.4	95.4	97.6			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD[4]		3773.1	4040.8	3935.7			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		1295.0	1295.0	1295.0			
MIN. MAR 31 RESERVOIR CONTENT, KSFD[5]		1051.1	783.4	888.5			
MIN. MAR 31 RESERVOIR ELEVATION, FT[6]		2419.1	2413.0	2415.4			
MAR 31 ECC, FT[7]		2409.9	2409.9	2409.9			
BASE ECC, FT	2409.9						
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]		3587.2	3841.7	3742.2	3777.7		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		920.0	920.0	920.0	920.0		
MIN. APR 30 RESERVOIR CONTENT, KSFD[5]		862.0	607.5	707.0	671.5		
MIN. APR 30 RESERVOIR ELEVATION, FT[6]		2414.8	2408.9	2411.2	2410.4		
APR 30 ECC, FT[7]		2403.1	2403.1	2403.1	2403.1		
BASE ECC, FT	2408.5						
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]		2895.1	3100.5	3020.3	3050.7	3046.3	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		610.0	610.0	610.0	610.0	610.0	
MIN. MAY 31 RESERVOIR CONTENT, KSFD[5]		1244.1	1038.7	1118.9	1088.5	1092.9	
MIN. MAY 31 RESERVOIR ELEVATION, FT[6]		2423.4	2418.8	2420.6	2419.9	2420.0	
MAY 31 ECC, FT[7]		2408.5	2408.5	2408.5	2408.5	2408.5	
BASE ECC, FT	2405.5						
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]		1451.5	1554.5	1512.2	1529.3	1526.9	1395.6
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]		2387.7	2284.7	2327.0	2309.9	2312.3	2443.6
MIN. JUN 30 RESERVOIR ELEVATION, FT[6]		2447.7	2445.6	2446.5	2446.1	2446.2	2448.8
JUN 30 ECC, FT[7]		2441.6	2441.6	2441.6	2441.6	2441.6	2441.6
BASE ECC, FT	2441.6						
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 (3579.6 KSFD) PLUS TWO PRECEDING
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 3

95 Percent Confidence Forecast and Variable Energy Content Curve Arrow 1989

	INITIAL	JAN 1 LOCAL	FEB 1 LOCAL	MAR 1 LOCAL	APR 1 LOCAL	MAY 1 LOCAL ·	JUN 1 LOCAL
1 PROBABLE FEB 1 - JUL 31 INFLOW, KSFD[1]		5666.4	5518.3	5257.5	5148.2	5313.0	5438.7
2 95% FORECAST ERROR, KSFD		956.5	775.1	664.5	546.9	521.8	557.2
3 95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD[2] ..		4709.9	4743.2	4593.0	4601.3	4791.2	4881.5
4 OBSERVED FEB 1 - DATE INFLOW, KSFD		0.0	0.0	208.3	364.8	878.5	2514.4
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD[3]		4709.9	4743.2	4384.7	4236.5	3912.7	2367.1
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME ..		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD[4]		4709.9					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		1454.0					
MICA REFILL REQUIREMENTS, KSFD[8]		2180.0					
MIN. JAN 31 RESERVOIR CONTENT, KSFD[5]		1856.3					
MIN. JAN 31 RESERVOIR ELEVATION, FT[6]		1377.9					
JAN 31 ECC, FT[7]		1392.1					
BASE ECC, FT	1418.0						
LOWER LIMIT, FT	1392.1						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME ..		96.8	96.8				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD[4]		4559.2	4591.4				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		1314.0	1314.0				
MICA REFILL REQUIREMENTS, KSFD[8]		1760.0	1760.0				
MIN. FEB 28 RESERVOIR CONTENT, KSFD[5]		1425.6	1457.8				
MIN. FEB 28 RESERVOIR ELEVATION, FT[6]		1377.9	1377.9				
FEB 28 ECC, FT[7]		1383.8	1383.8				
BASE ECC, FT	1410.7						
LOWER LIMIT, FT	1383.8						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME ..		93.1	93.1	96.1			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD[4]		4384.9	4415.9	4213.7			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		1159.0	1159.0	1719.3			
MICA REFILL REQUIREMENTS, KSFD[8]		941.3	1295.0	1295.0			
MIN. MAR 31 RESERVOIR CONTENT, KSFD[5]		1377.9	-972.3	-209.8			
MIN. MAR 31 RESERVOIR ELEVATION, FT[6]		1382.3	1377.9	1377.9			
MAR 31 ECC, FT[7]		1406.7	1382.3	1382.3			
BASE ECC, FT	1415.9						
LOWER LIMIT, FT	1382.3						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME ..		85.2	85.2	88.0	91.5		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD[4]		4012.8	4041.2	3858.5	3876.4		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		1009.0	1009.0	1500.3	1009.0		
MICA REFILL REQUIREMENTS, KSFD[8]		920.0	920.0	920.0	920.0		
MIN. APR 30 RESERVOIR CONTENT, KSFD[5]		344.2	-372.6	301.4	-207.8		
MIN. APR 30 RESERVOIR ELEVATION, FT[6]		1377.9	1377.9	1385.1	1377.9		
APR 30 ECC, FT[7]		1377.9	1377.9	1385.1	1377.9		
BASE ECC, FT	1409.5						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME ..		61.3	61.3	63.3	65.9	72.0	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD[4]		2887.2	2907.6	2775.5	2791.9	2817.1	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		854.0	854.0	1274.0	854.0	854.0	
MICA REFILL REQUIREMENTS, KSFD[8]		610.0	610.0	610.0	610.0	610.0	
MIN. MAY 31 RESERVOIR CONTENT, KSFD[5]		936.4	916.5	1468.1	1031.7	1006.5	
MIN. MAY 31 RESERVOIR ELEVATION, FT[6]		1398.5	1398.1	1408.7	1400.4	1399.9	
MAY 31 ECC, FT[7]		1398.5	1398.1	1408.7	1400.4	1399.9	
BASE ECC, FT	1425.6						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME ..		26.7	26.7	27.6	28.7	31.4	43.6
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD[4]		1257.5	1266.4	1210.2	1215.9	1228.6	1126.2
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		434.0	434.0	666.5	434.0	434.0	434.0
MIN. JUN 30 RESERVOIR CONTENT, KSFD[5]		310.0	310.0	310.0	310.0	310.0	310.0
MICA REFILL REQUIREMENTS, KSFD[9]		2446.1	2437.2	2725.9	2487.7	2475.0	2577.4
MIN. JUN 30 RESERVOIR ELEVATION, FT[6]		1425.9	1425.8	1430.5	1426.6	1426.4	1428.1
JUN 30 ECC, FT[7]		1425.9	1425.8	1430.5	1426.6	1426.4	1428.1
BASE ECC, FT	1444.0						
JUL 31 ECC, FT		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 1989

	INITIAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1 PROBABLE FEB 1 - JUL 31 INFLOW, KSFD[1]		875.2	874.9	861.8	846.2	861.5	836.8
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] ..		767.9	776.5	768.0	751.9	777.1	750.1
4 OBSERVED FEB 1 - DATE INFLOW, KSFD		0.0	0.0	15.5	34.2	91.9	254.7
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD[3]		767.9	776.5	752.5	717.7	685.2	495.4
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME ..		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD[4]		767.9					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		18.1					
MIN. JAN 31 RESERVOIR CONTENT, KSFD[5]		-44.0					
MIN. JAN 31 RESERVOIR ELEVATION, FT[6]		1794.2					
JAN 31 ECC, FT[7]		1794.5					
BASE ECC, FT	1848.6						
LOWER LIMIT, FT	1794.5						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME ..		97.9	97.9				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD[4]		751.8	760.2				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		15.3	15.3				
MIN. FEB 28 RESERVOIR CONTENT, KSFD[5]		-30.7	-39.1				
MIN. FEB 28 RESERVOIR ELEVATION, FT[6]		1794.2	1794.2				
FEB 28 ECC, FT[7]		1794.6	1794.6				
BASE ECC, FT	1834.9						
LOWER LIMIT, FT	1794.6						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME ..		95.4	95.4	97.5			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD[4]		732.6	740.8	733.7			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		12.2	12.2	61.0			
MIN. MAR 31 RESERVOIR CONTENT, KSFD[5]		14.6	-22.8	33.1			
MIN. MAR 31 RESERVOIR ELEVATION, FT[6]		1794.2	1794.2	1801.7			
MAR 31 ECC, FT[7]		1794.4	1794.4	1801.7			
BASE ECC, FT	1836.9						
LOWER LIMIT, FT	1794.4						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME ..		89.9	89.9	91.9	94.3		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD[4]		690.3	698.1	691.5	676.8		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		9.2	9.2	46.0	9.2		
MIN. APR 30 RESERVOIR CONTENT, KSFD[5]		24.7	16.9	60.3	38.2		
MIN. APR 30 RESERVOIR ELEVATION, FT[6]		1799.9	1798.3	1806.8	1802.7		
APR 30 ECC, FT[7]		1799.9	1798.3	1806.8	1802.7		
BASE ECC, FT	1833.9						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME ..		69.4	69.4	71.0	72.8	77.2	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD[4]		532.9	538.9	534.3	522.5	529.0	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		6.1	6.1	30.5	6.1	6.1	
MIN. MAY 31 RESERVOIR CONTENT, KSFD[5]		179.0	173.0	202.0	189.4	182.9	
MIN. MAY 31 RESERVOIR ELEVATION, FT[6]		1826.0	1825.1	1829.3	1827.5	1826.5	
MAY 31 ECC, FT[7]		1826.0	1825.1	1829.3	1827.5	1826.5	
BASE ECC, FT	1848.4						
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]		252.6	255.5	252.8	246.9	250.1	234.3
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		3.1	3.1	15.5	3.1	3.1	3.1
MIN. JUN 30 RESERVOIR CONTENT, KSFD[5]		456.3	453.4	468.5	462.0	458.8	474.6
MIN. JUN 30 RESERVOIR ELEVATION, FT[6]		1862.8	1862.5	1864.3	1863.5	1863.1	1865.0
JUN 30 ECC, FT[7]		1862.8	1871.5	1864.3	1863.5	1863.1	1865.0
BASE ECC, FT	1871.9						
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 1989

	INITIAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1 PROBABLE JAN 1 - JUL 31 INFLOW, KSFD		3189.4	3134.2	2857.2	3160.9	3148.3	3172.8
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	93.0	161.9	254.9	531.2	1306.9
4 95% CONF DATE - JUL 31 INFLOW, KSFD[1]		2302.6	2434.7	2142.8	2372.6	2142.6	1498.4
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME ..		97.1					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD[2]		2236.7					
FEB MINIMUM FLOW REQUIREMENTS, CFS[3]		4000.0					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD[4]		724.0					
MIN. JAN 31 RESERVOIR CONTENT, KSFD[5]		997.8					
MIN. JAN 31 RESERVOIR ELEVATION, FT[6]		2379.4					
JAN 31 ECC, FT[7]		2379.4					
BASE ECC, FT	2412.1						
LOWER LIMIT, FT	2313.6						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME ..		94.4	97.2				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD[4]		2175.2	2367.8				
MAR MINIMUM FLOW REQUIREMENT, CFS[3]		4000.0	4000.0				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		612.0	612.0				
MIN. FEB 1 RESERVOIR CONTENT, KSFD[5]		947.3	754.7				
MIN. FEB 1 RESERVOIR ELEVATION, FT[6]		2375.7	2361.3				
FEB 28 ECC, FT[7]		2375.7	2361.3				
BASE ECC, FT	2405.3						
LOWER LIMIT, FT	2304.2						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME ..		91.2	93.9	96.6			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD[4]		2100.9	2286.7	2069.5			
APR MINIMUM FLOW REQUIREMENT, CFS[3]		4000.0	4000.0	4000.0			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		488.0	488.0	488.0			
MIN. MAR 31 RESERVOIR CONTENT, KSFD[5]		897.6	711.8	929.0			
MIN. MAR 31 RESERVOIR ELEVATION, FT[6]		2372.1	2357.9	2374.4			
MAR 31 ECC, FT[7]		2372.1	2357.9	2374.4			
BASE ECC, FT	2400.5						
LOWER LIMIT, FT	2287.0						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME ..		83.2	85.6	88.0	91.2		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD[4]		1916.0	2085.3	1887.3	2163.8		
MAY MINIMUM FLOW REQUIREMENT, CFS[3]		4000.0	4000.0	4000.0	4000.0		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		368.0	368.0	368.0	368.0		
MIN. APR 30 RESERVOIR CONTENT, KSFD[5]		962.5	793.2	991.2	714.7		
MIN. APR 30 RESERVOIR ELEVATION, FT[6]		2376.8	2364.2	2378.9	2358.1		
APR 30 ECC, FT[7]		2376.8	2364.2	2378.9	2358.1		
BASE ECC, FT	2399.0						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME ..		56.8	57.5	59.1	61.2	67.1	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD[4]		1309.2	1400.0	1267.0	1452.5	1438.3	
JUN MINIMUM FLOW REQUIREMENT, CFS[3]		4000.0	4000.0	4000.0	4000.0	4000.0	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		244.0	244.0	244.0	244.0	244.0	
MIN. MAY 31 RESERVOIR CONTENT, KSFD[5]		1445.8	1354.5	1487.5	1302.0	1316.2	
MIN. MAY 31 RESERVOIR ELEVATION, FT[6]		2407.8	2402.6	2410.2	2399.5	2400.4	
MAY 31 ECC, FT[7]		2407.8	2402.6	2410.2	2399.5	2400.4	
BASE ECC, FT	2423.9						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME ..		19.4	19.9	20.5	21.3	23.3	34.7
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD[4]		446.9	486.5	440.1	504.7	499.7	520.6
JUN MINIMUM FLOW REQUIREMENT, CFS[3]		4000.0	4000.0	4000.0	4000.0	4000.0	4000.0
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		124.0	124.0	124.0	124.1	124.0	124.0
MIN. JUN 30 RESERVOIR CONTENT, KSFD[5]		2187.6	2148.0	2194.4	2129.8	2134.8	2113.9
MIN. JUN 30 RESERVOIR ELEVATION, FT[6]		2444.8	2443.0	2445.1	2442.1	2442.4	2441.4
JUN 30 ECC, FT[7]		2444.8	2443.0	2445.1	2442.1	2442.4	2441.4
BASE ECC, FT	2449.8						
JUL 31 ECC, FT		2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
JAN 1 - JUL 31 FORECAST, EARLYBIRD, MAF[8].....	98.6	102.0	92.5	100.0	99.5	99.5	99.5
AT THE DALLES, OFFICIAL, MAF..................	0.0	0.0	0.0	0.0	0.0	0.0	0.0

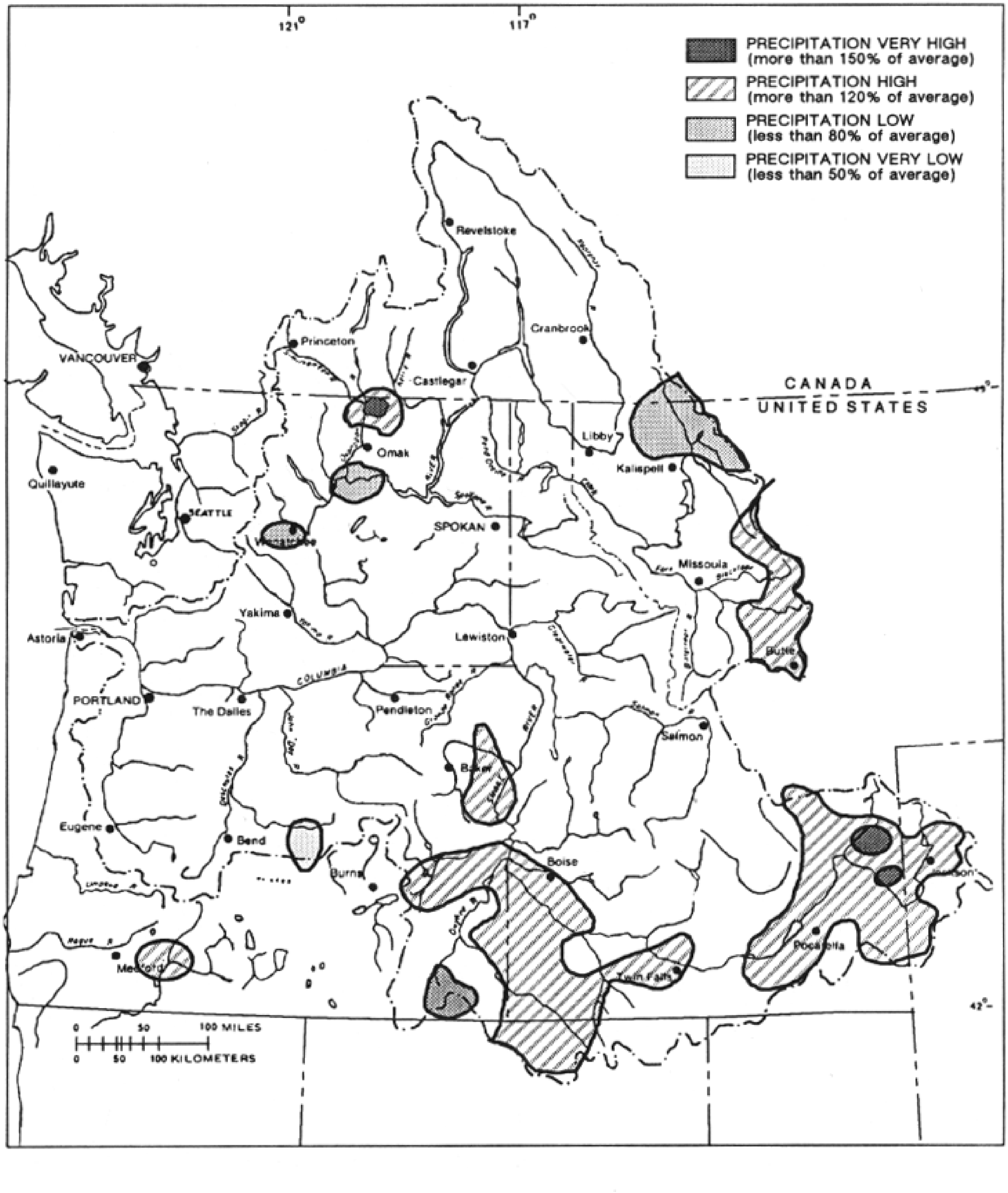
1 LINE 1 - LINE 2-LINE 3
2 PRECEDING LINE TIMES LINE 4
3 BASED ON POWER DISCHARGE REQUIREMENTS, DETERMINED FROM 8
4 CUMULATIVE MINIMUM OUTFLOW FROM 3, FROM DATE TO JULY
5 FULL CONTENT (2510.5 KSFD) PLUS 4, AND MINUS 2
6 ELEVATION FROM 5, STORAGE CONTENT TABLE, DATED JUNE 1980
7 ELEVATION FROM 6, BUT 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 1989

1 May Forecast of May-August Unregulated Runoff Volume, MAF		74.8
Less Estimated Depletions, MAF		1.5
Less Upstream Storage Corrections, MAF		
MICA	6.4	
ARROW	5.0	
LIBBY	4.0	
DUNCAN	1.3	
HUNGRY HORSE	1.6	
FLATHEAD LAKE	.5	
NOXON	.0	
PEND OREILLE LAKE	.5	
GRAND COULEE	3.3	
BROWNLEE	0.4	
DWORSHAK	0.9	
JOHN DAY	0.2	
TOTAL	24.1	24.1
Forecast of Adjusted Residual Runoff Volume, MAF		49.2
Computed Initial Controlled Flow from Chart 1 of Flood Control Operating Plan, 1,000 cfs		307.0

Seasonal Precipitation Chart 1
Columbia River Basin
October 1988 - March 1989
Percent of 1961-1985 Average



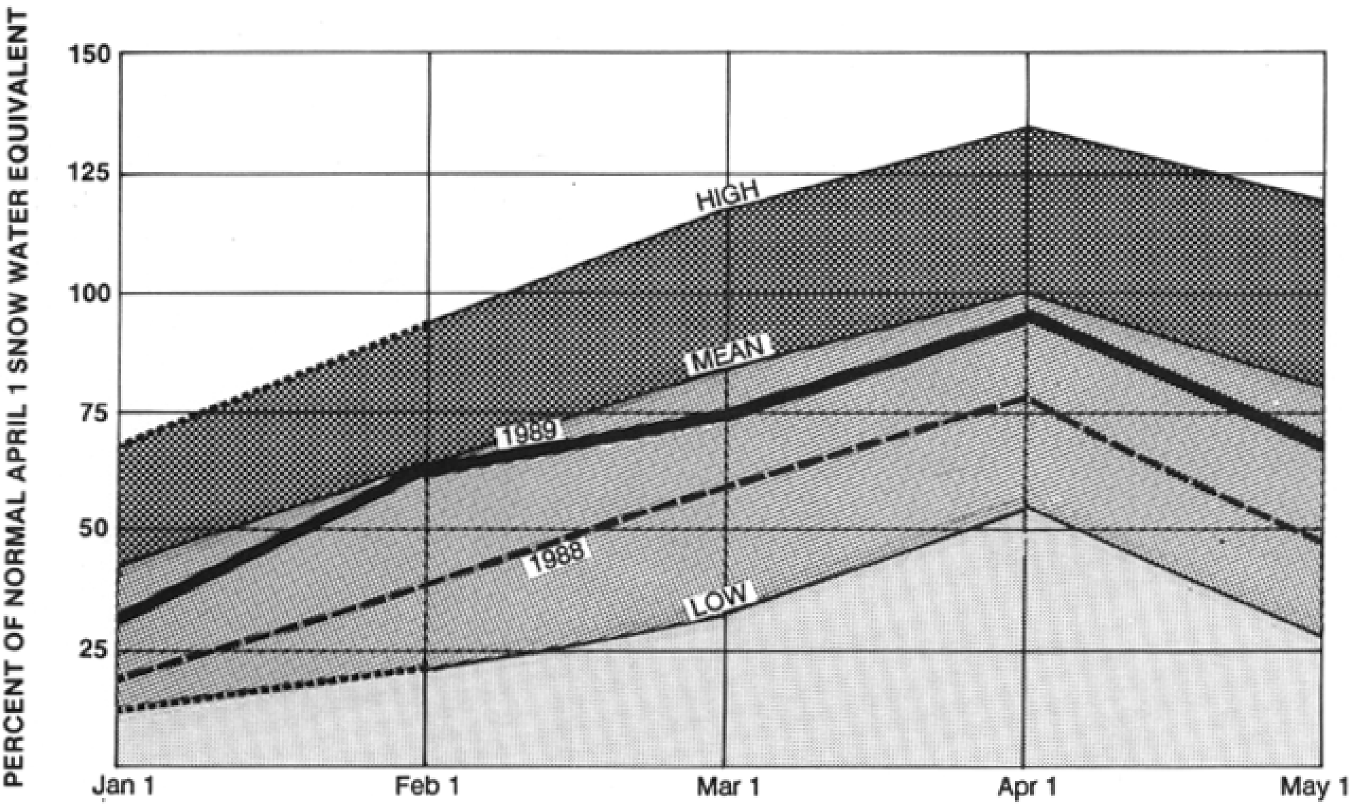
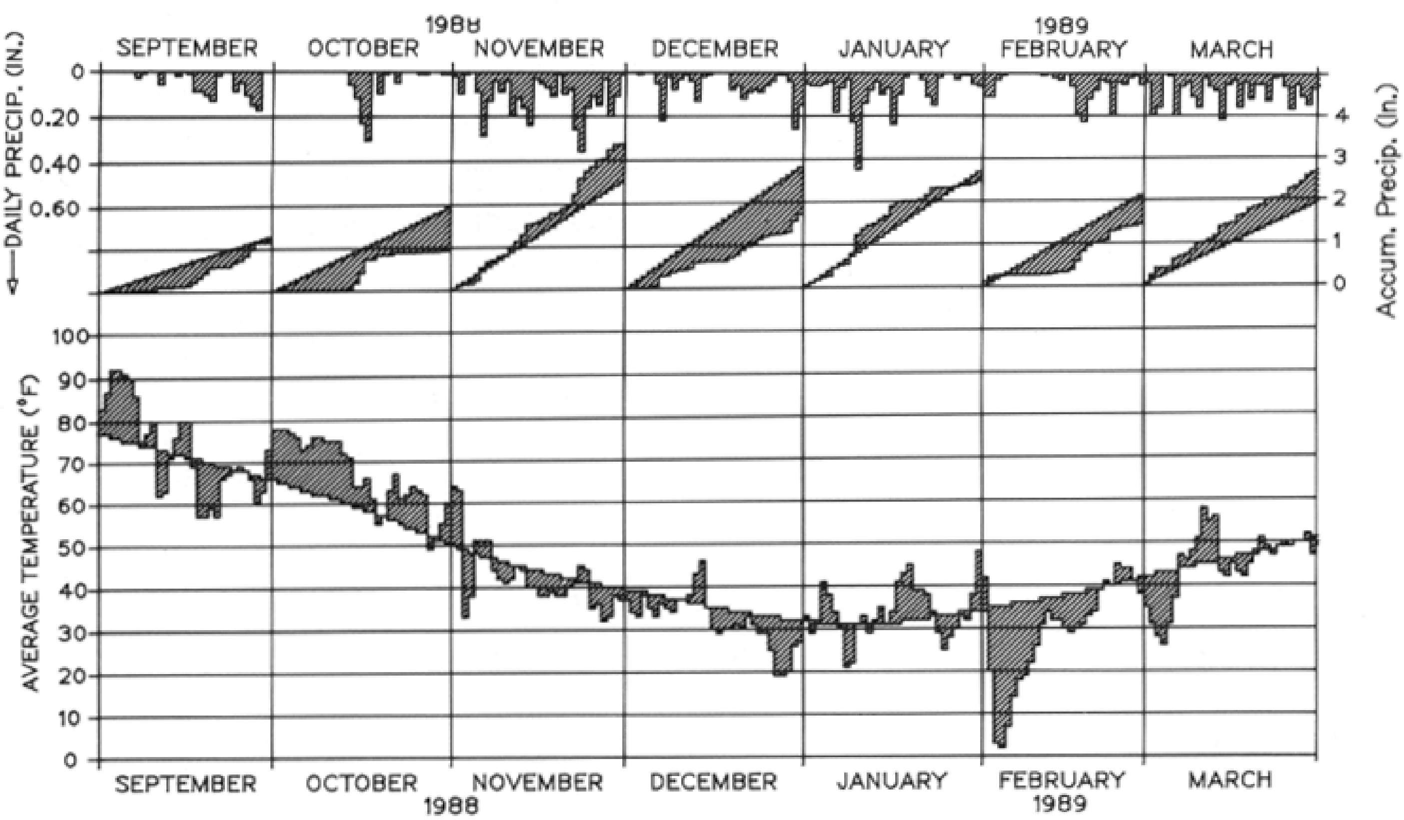
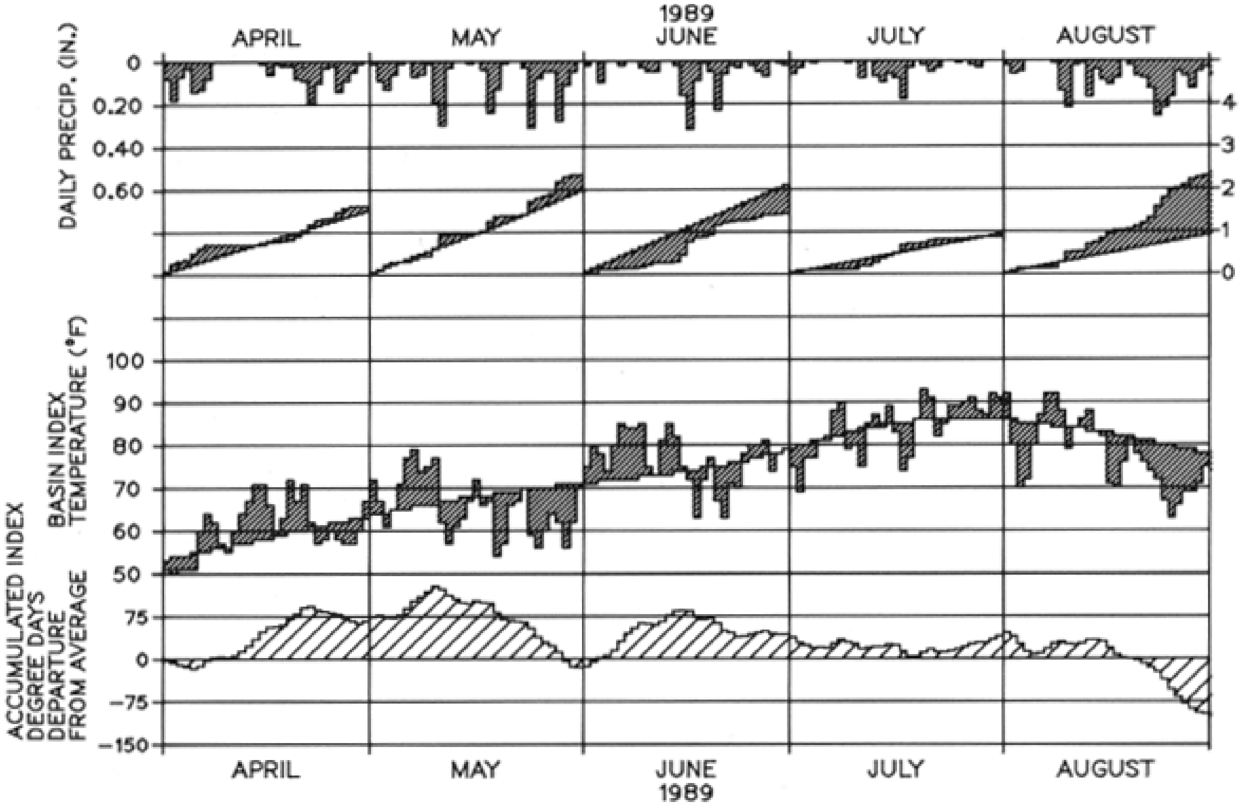


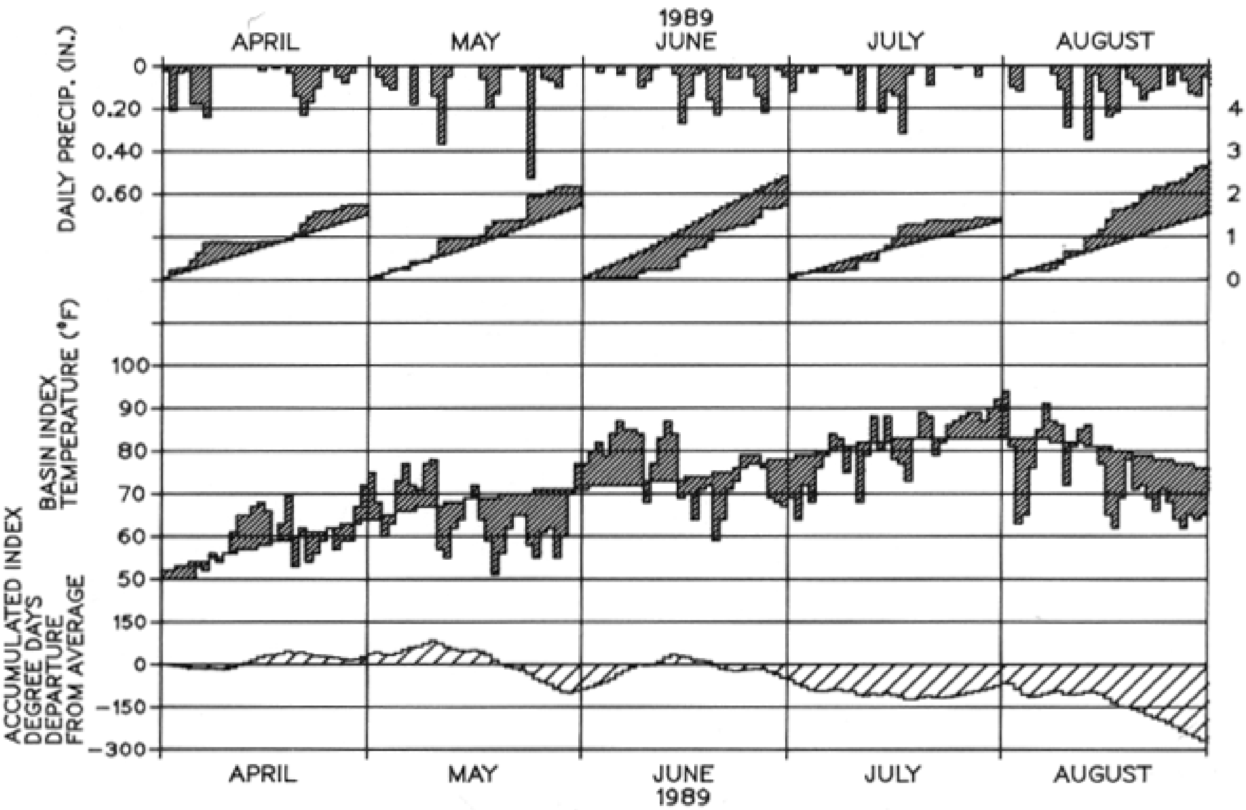
Chart 2
Columbia Basin Snowpack



WINTER SEASON Chart 3
Temperature and Precipitation Index 1988–1989
Columbia River Basin Above The Dalles, OR



SNOWMELT SEASON Chart 4
Temperature and Precipitation Index 1988–1989
Columbia River Basin Above The Dalles, OR



SNOWMELT SEASON Chart 5
Temperature and Precipitation Index 1988–1989
Columbia River Basin In Canada

Chart 6
Regulation of Mica
1 July 1988 – 31 July 1989

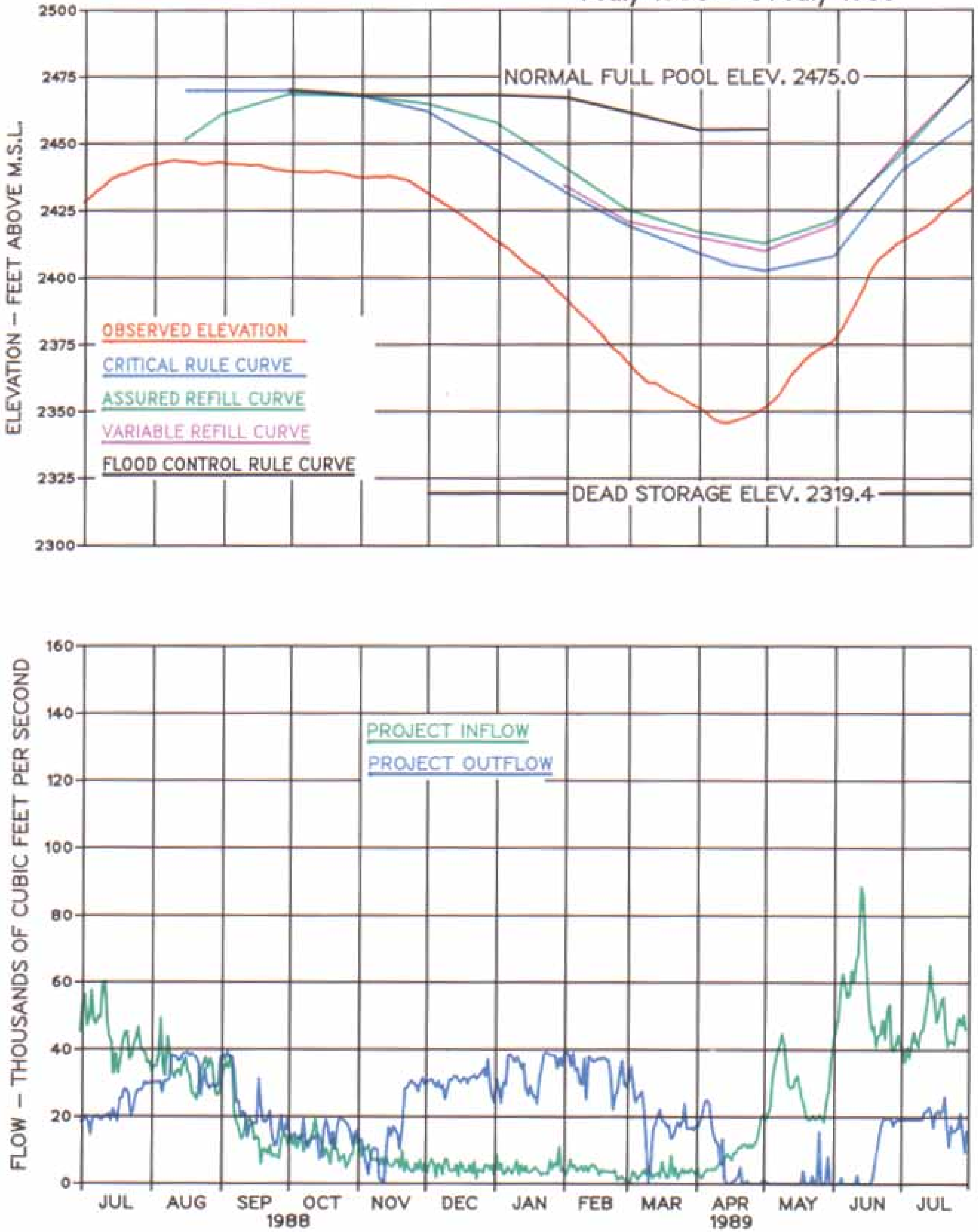
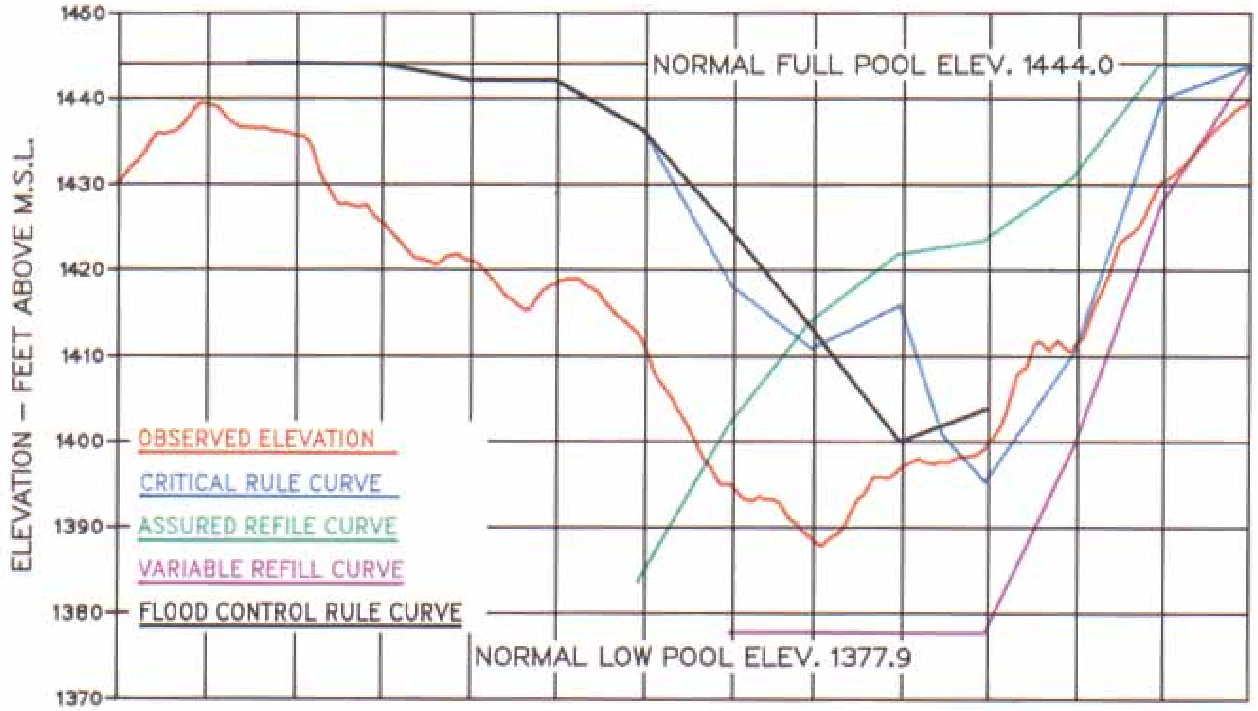


Chart 7
Regulation of Arrow
1 July 1988 – 31 July 1989



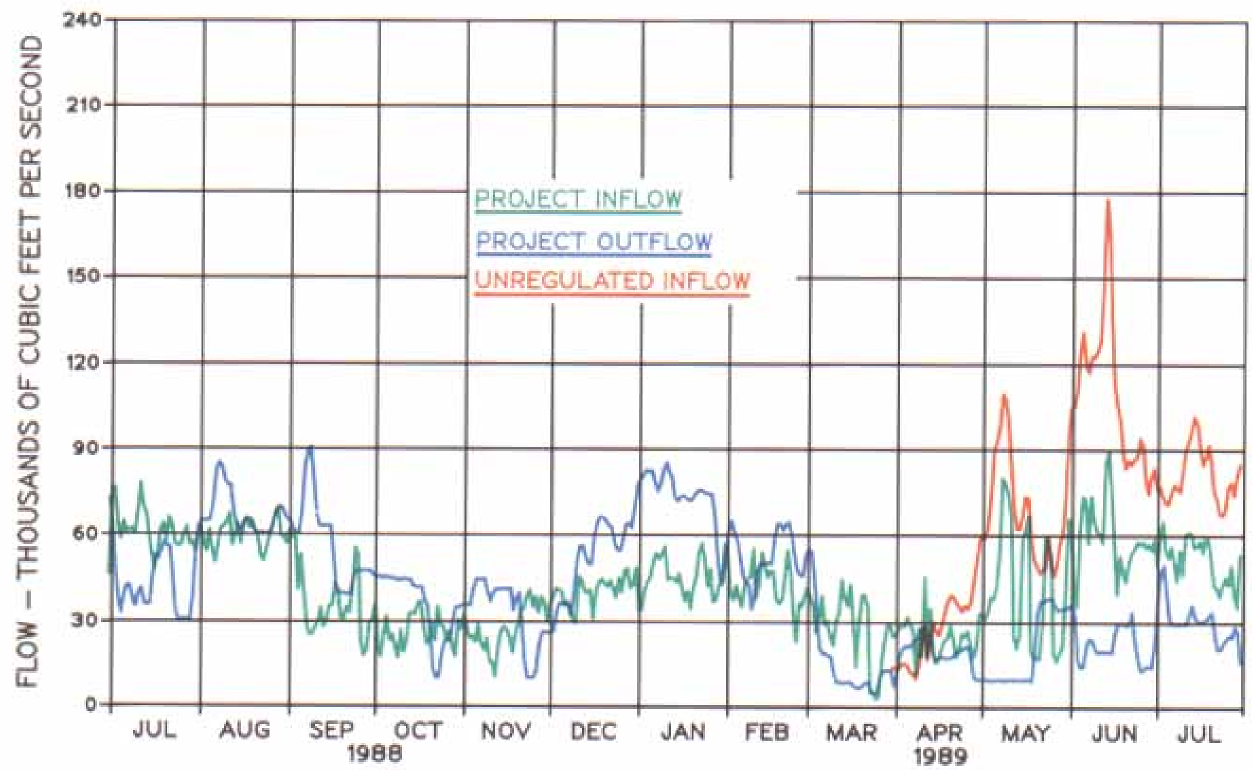
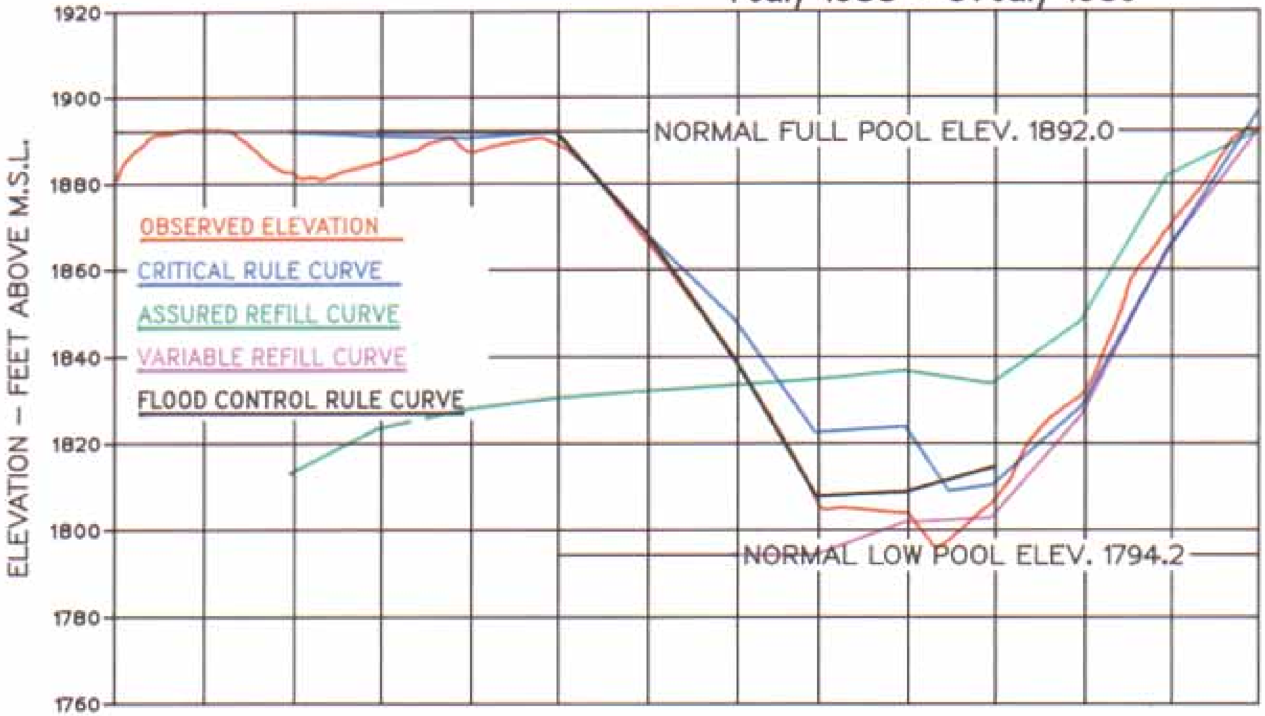


Chart 8
Regulation of Duncan
1 July 1988 – 31 July 1989



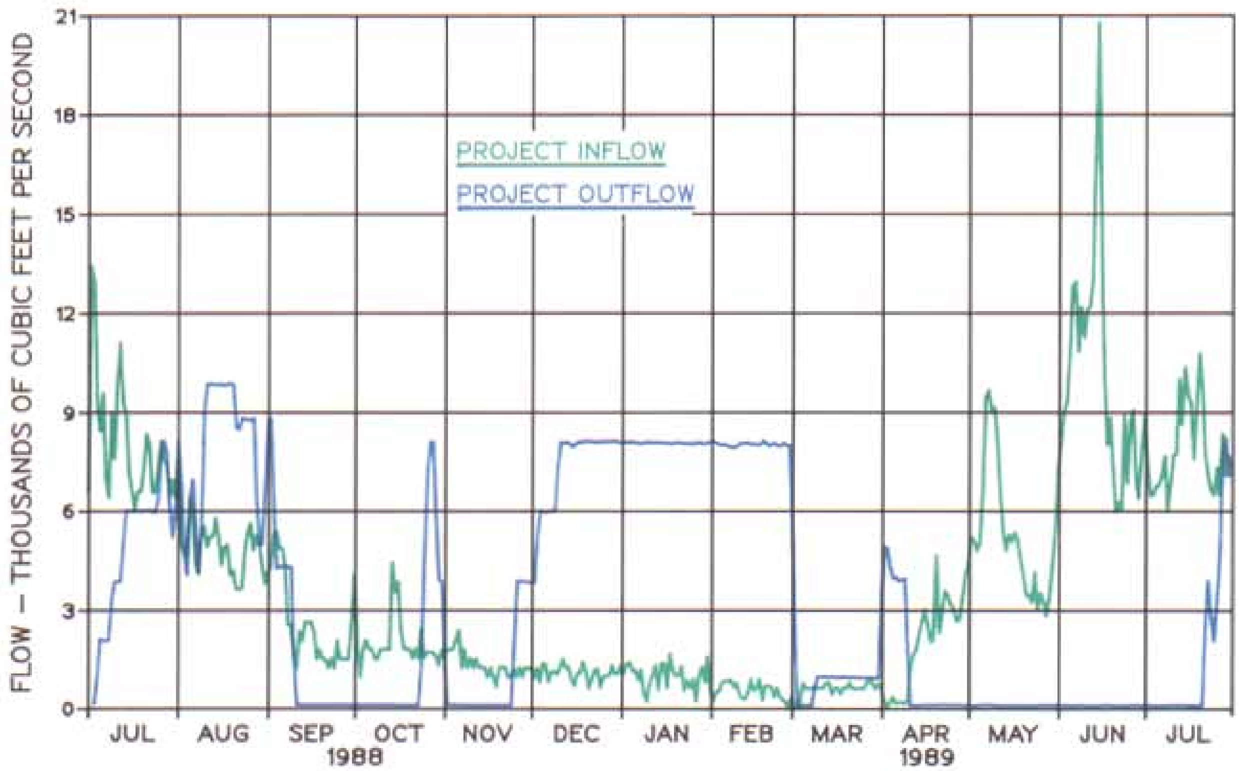
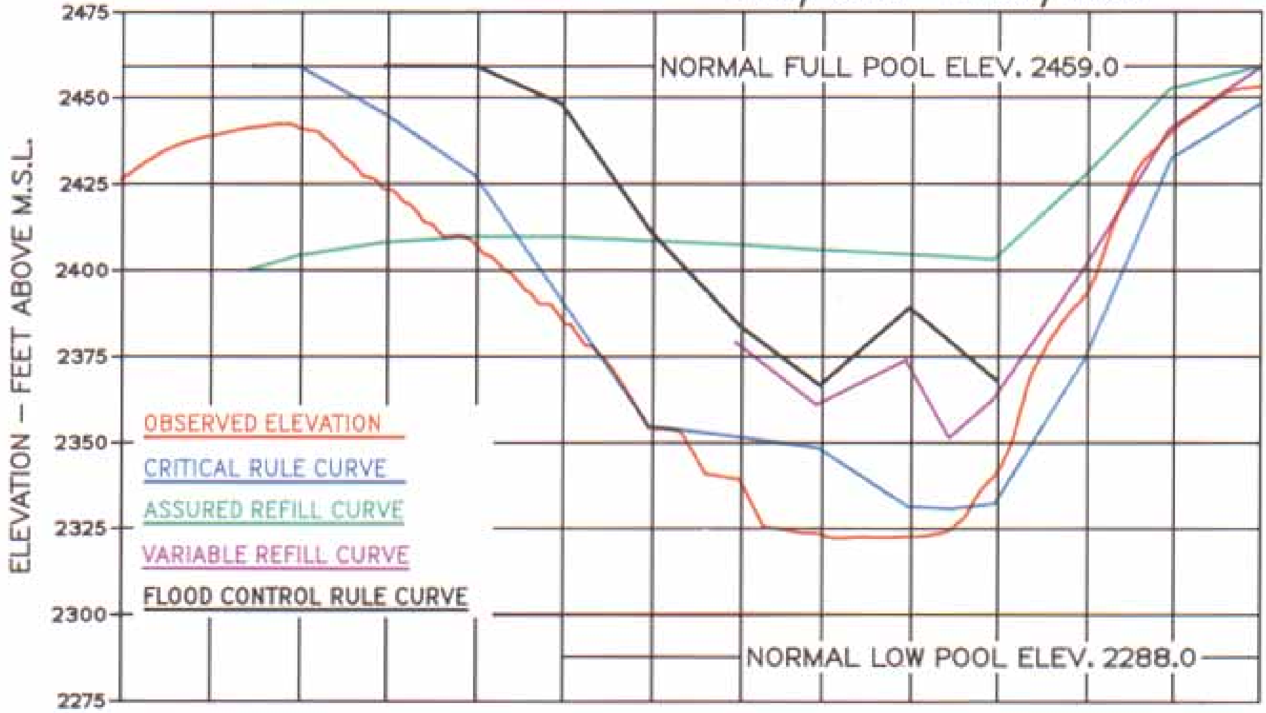


Chart 9
Regulation of Libby
1 July 1988 – 31 July 1989



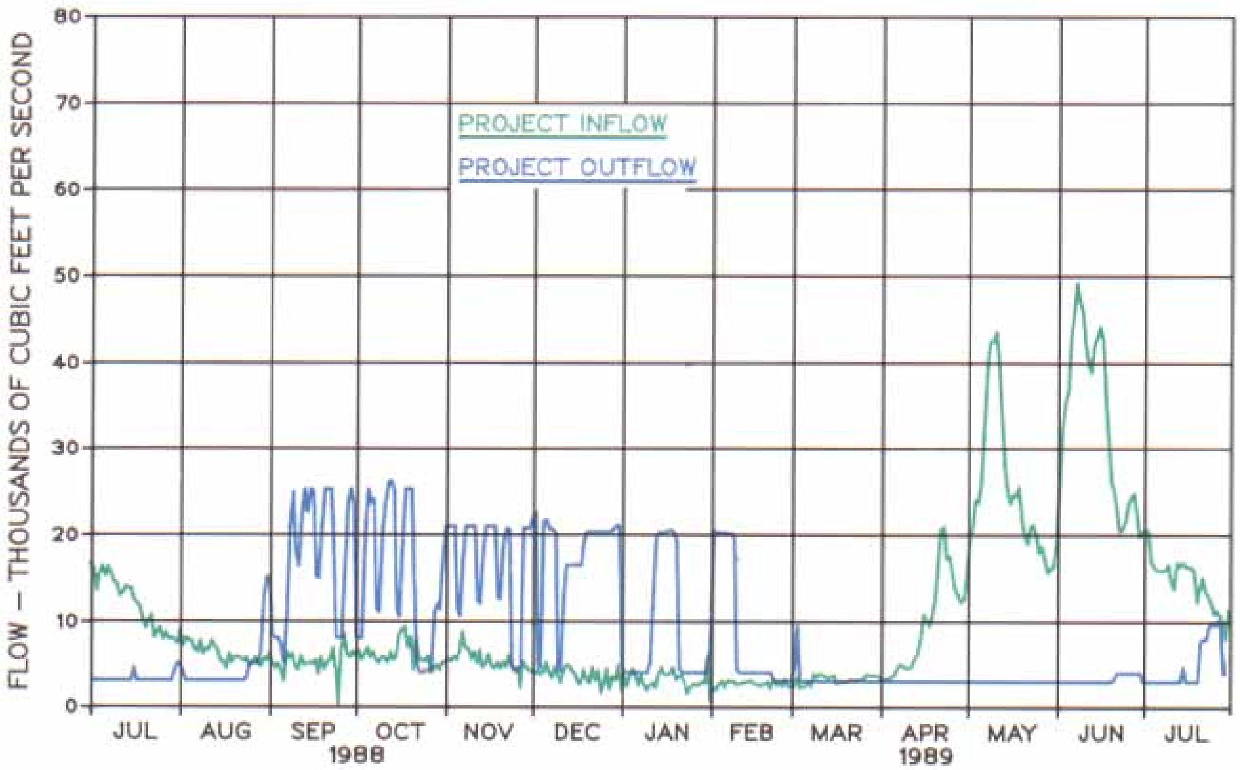


Chart 10
Regulation of Kootenay Lake
1 July 1988 – 31 July 1989

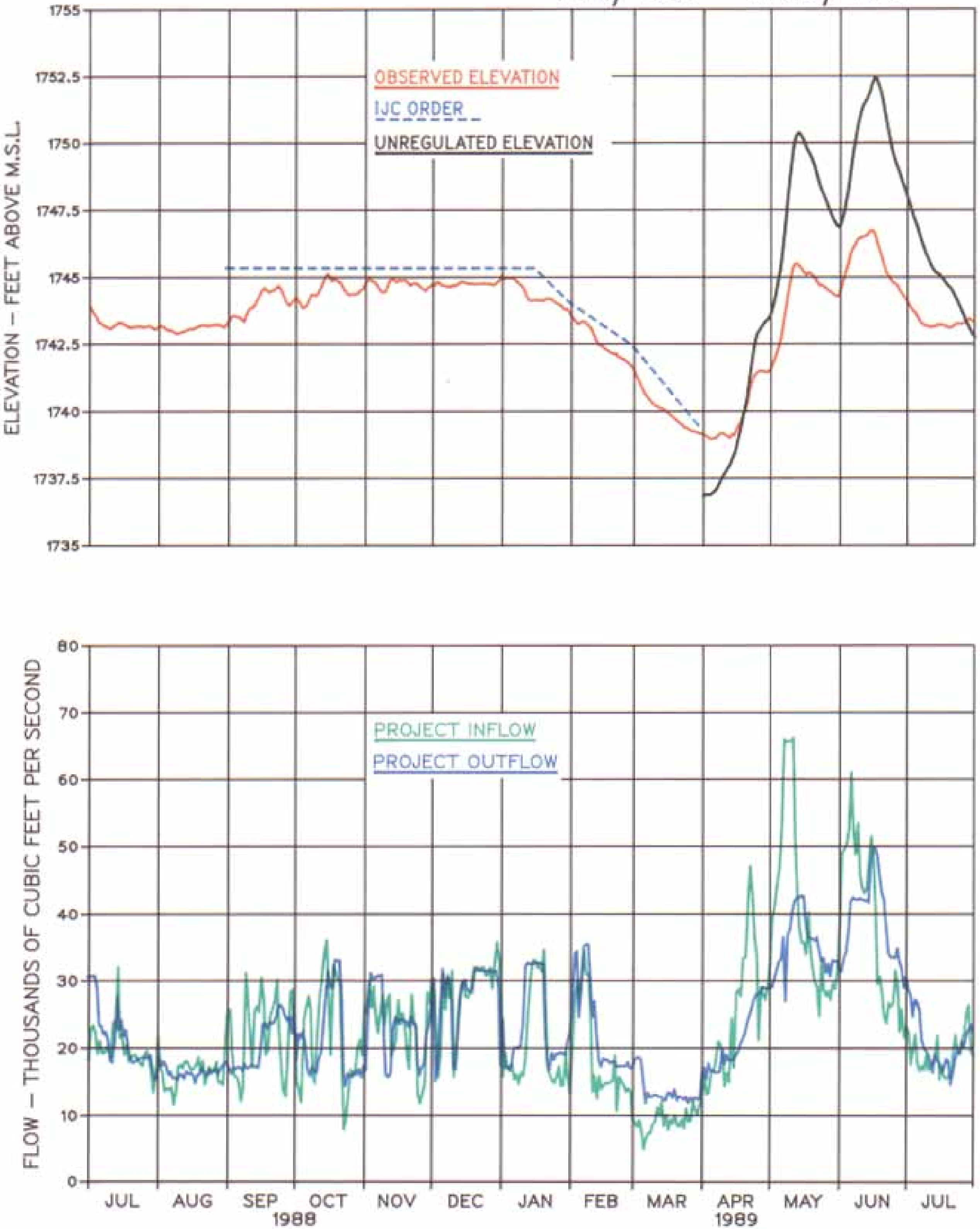


Chart 11
Columbia River at Birchbank
1 July 1988 – 31 July 1989

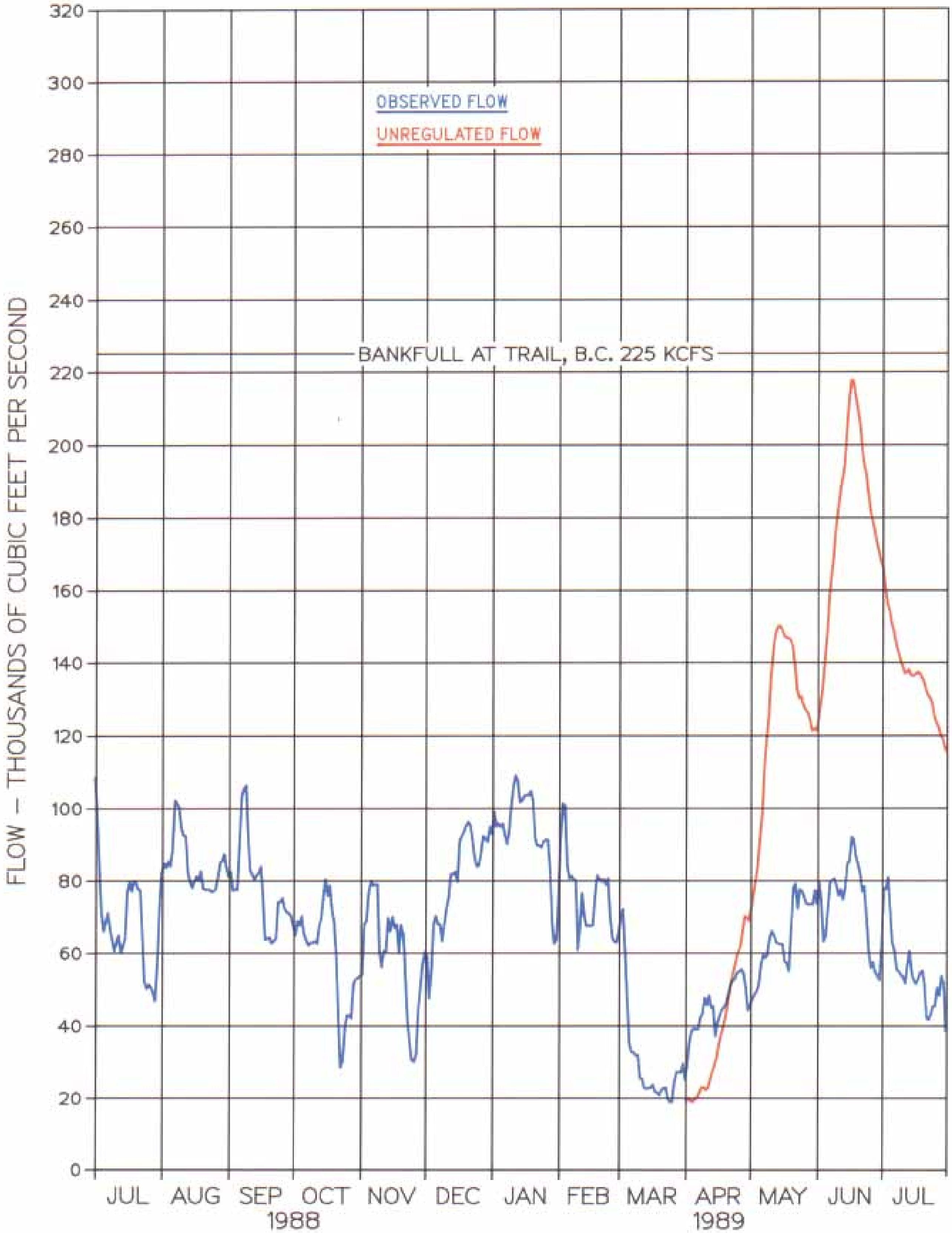


Chart 12
Regulation of Grand Coulee
1 July 1988 – 31 July 1989

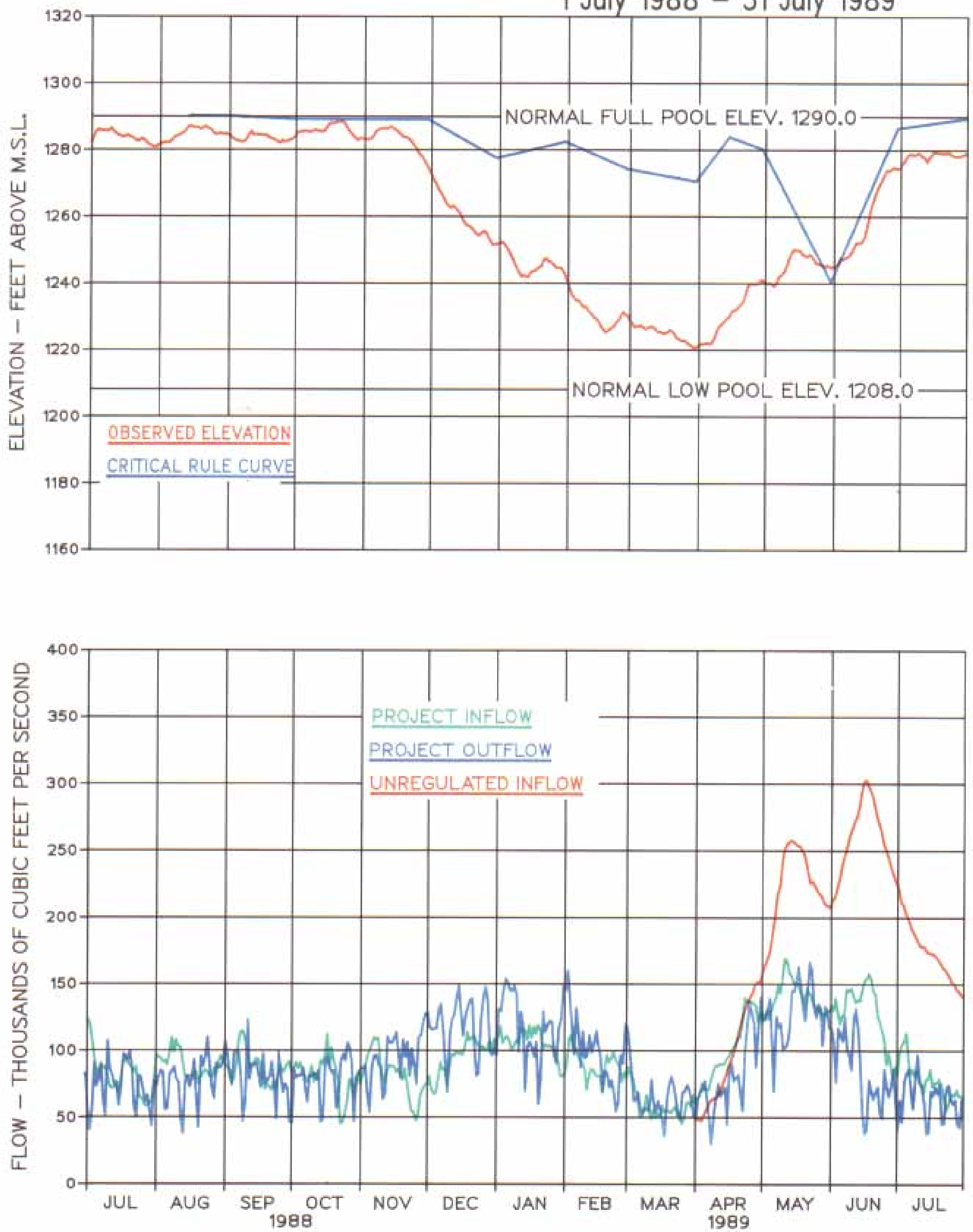


CHART 13
Columbia River at The Dalles
1 July 1988 – 31 July 1989

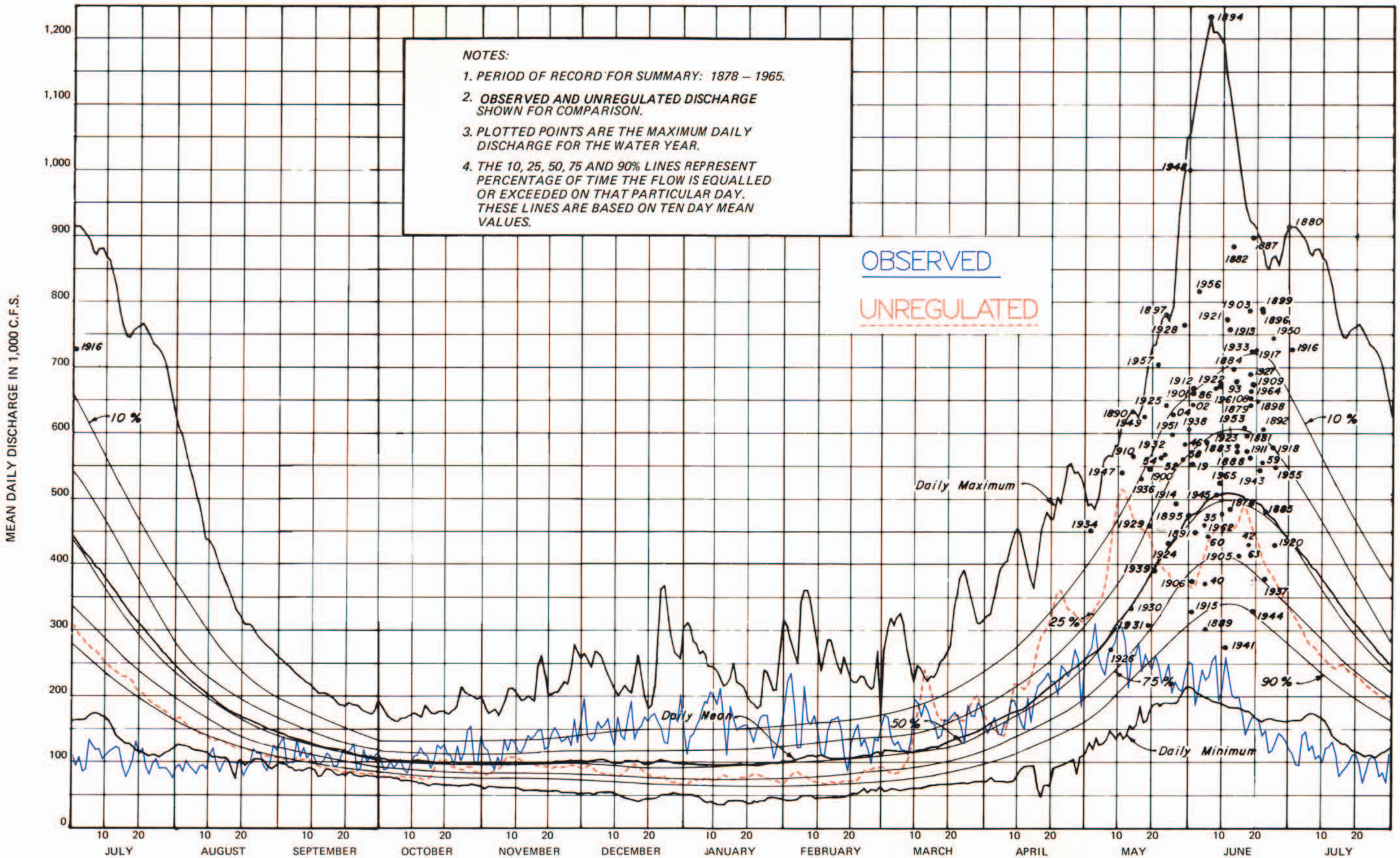
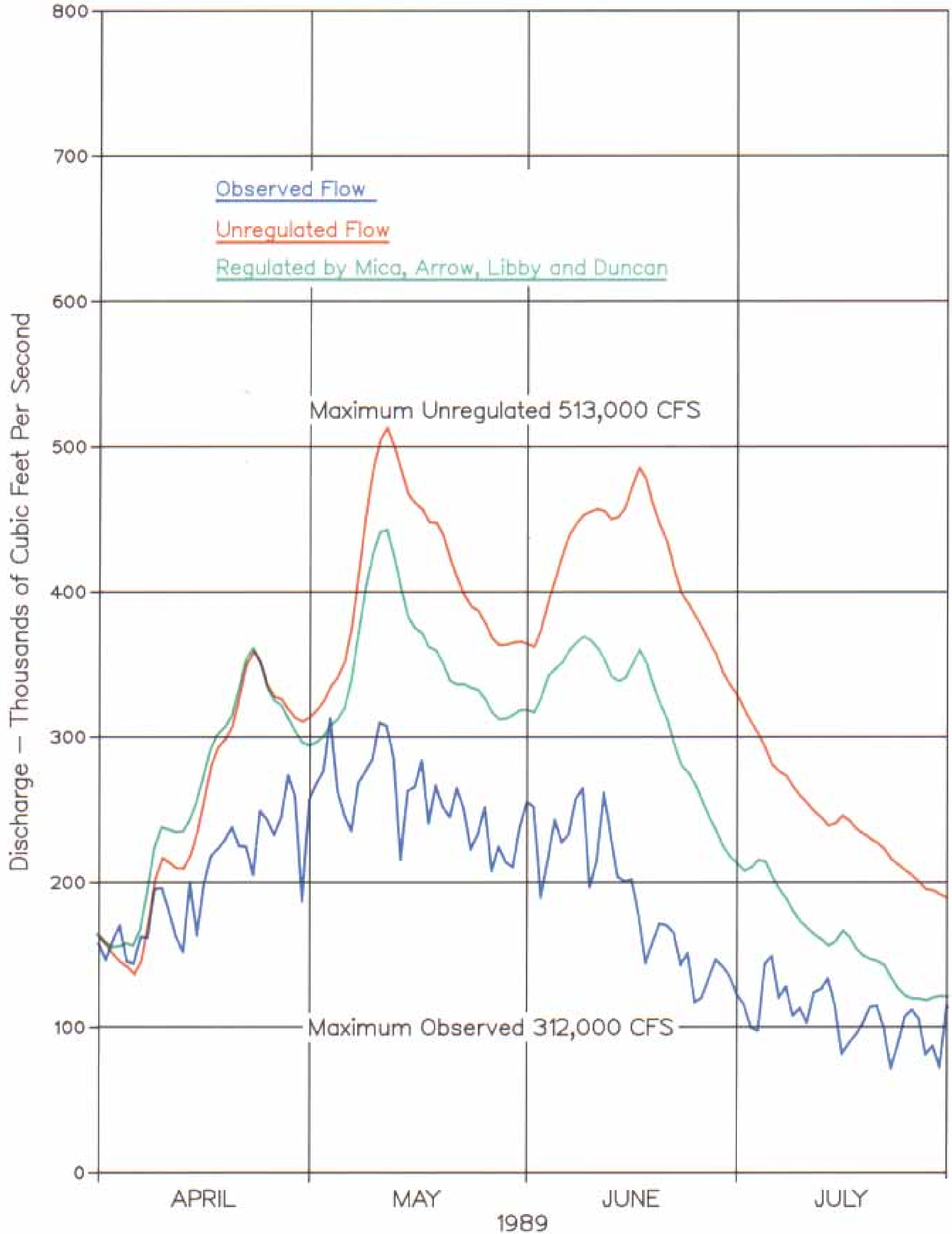


Chart 14
Columbia River at The Dalles
1 April 1989 – 31 July 1989



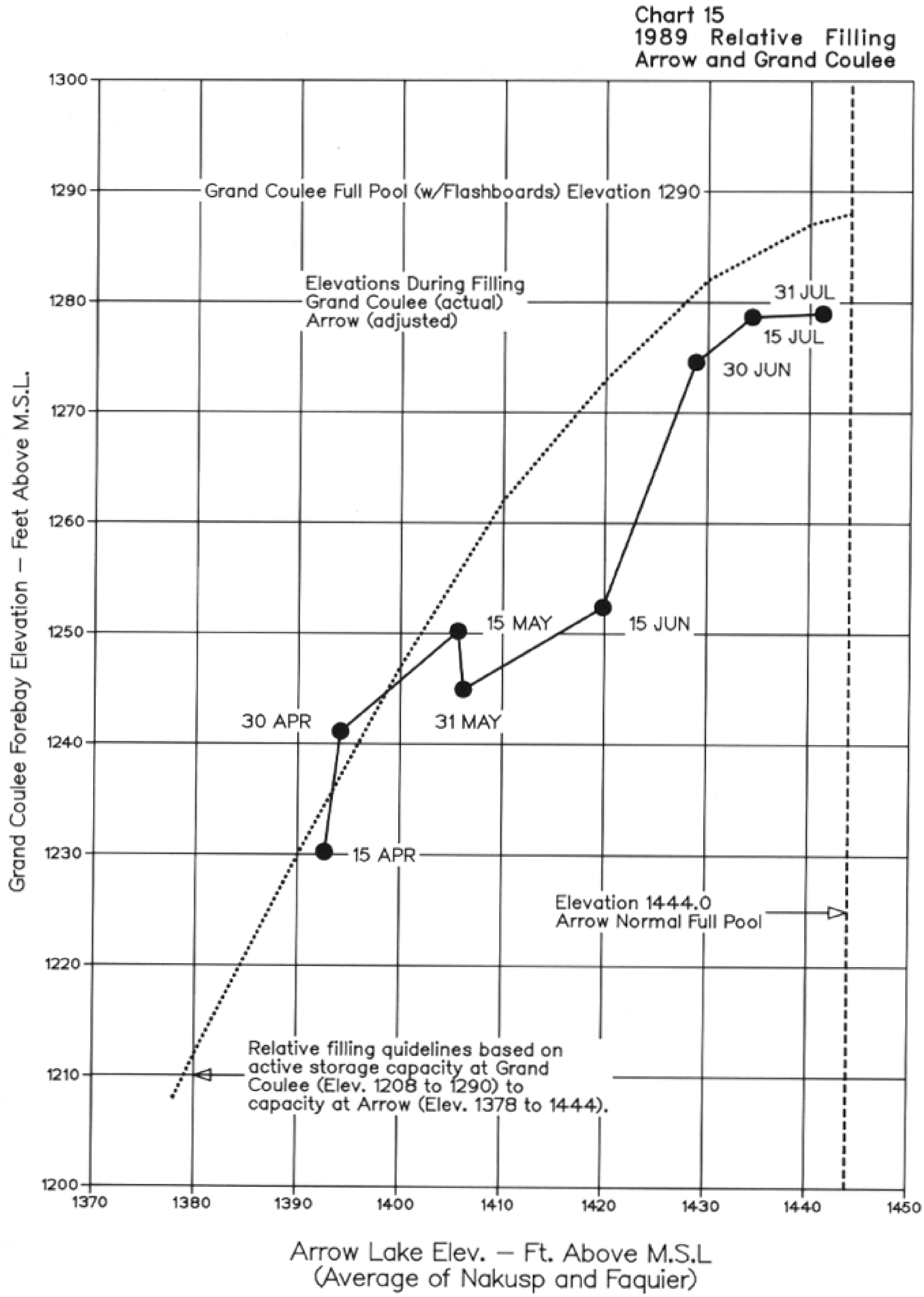


Chart 15
1989 Relative Filling
Arrow and Grand Coulee
Grand Coulee Full Pool (w/Flashboards) Elevation 1290
Elevations During Filling
Grand Coulee (actual)
Arrow (adjusted)
31 JUL
15 JUL
30 JUN
15 MAY
15 JUN
30 APR
31 MAY
15 APR
Elevation 1444.0
Arrow Normal Full Pool
Relative filling quidelines based on
active storage capacity at Grand
Coulee (Elev. 1208 to 1290) to
capacity at Arrow (Elev. 1378 to 1444).
Grand Coulee Forebay Elevation — Feet Above M.S.L.
Arrow Lake Elev. — Ft. Above M.S.L
(Average of Nakusp and Faquier)
1300
1290
1280
1270
1260
1250
1240
1230
1220
1210
1200
1370
1380
1390
1400
1410
1420
1430
1440
1450