COLUMBIA RIVER TREATY

ASSURED OPERATING PLAN,

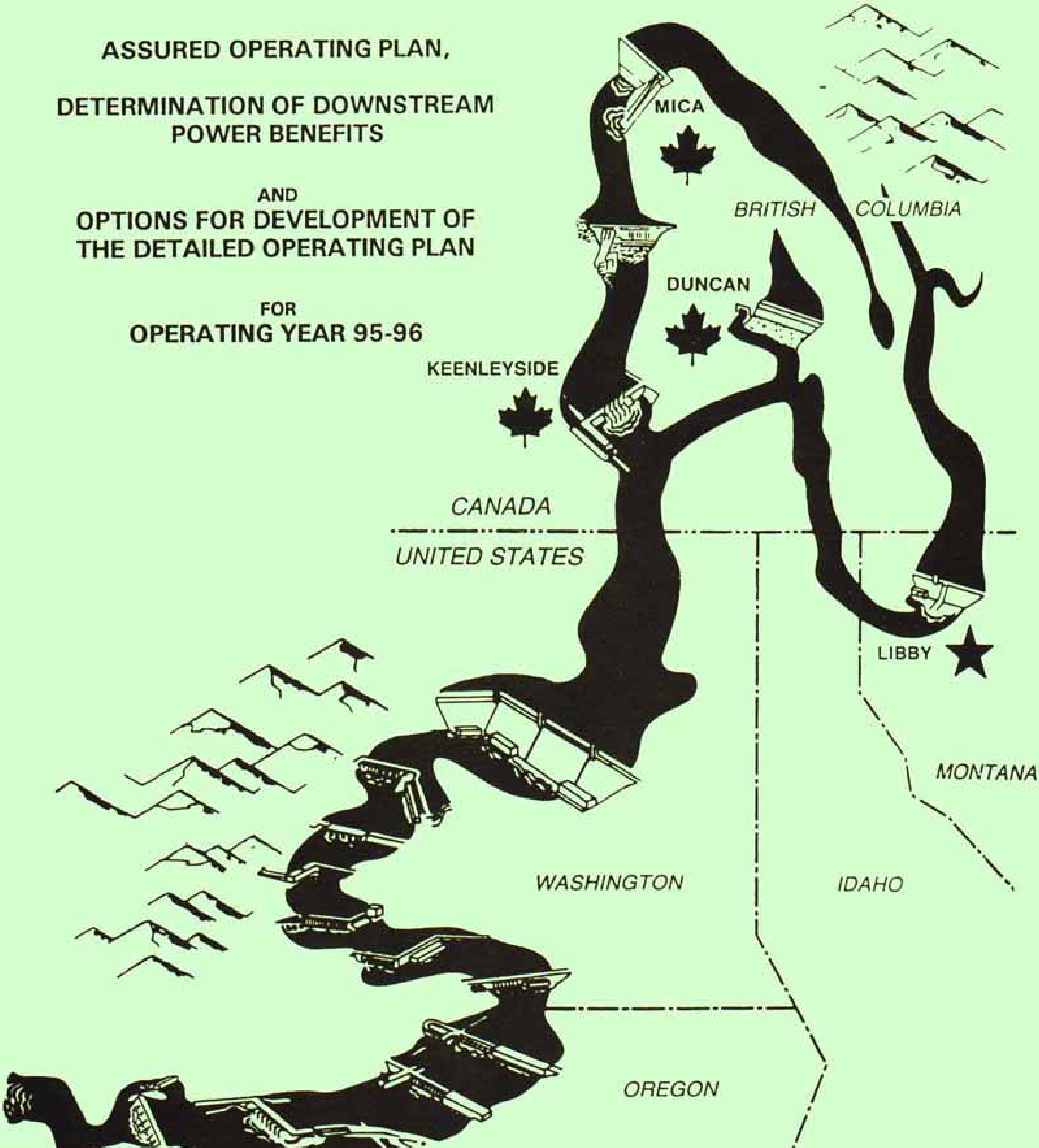
DETERMINATION OF DOWNSTREAM POWER BENEFITS

AND

OPTIONS FOR DEVELOPMENT OF THE DETAILED OPERATING PLAN

FOR

OPERATING YEAR 95-96



COLUMBIA RIVER TREATY OPERATING COMMITTEE

JANUARY 1991

Columbia River Treaty

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Preface

Hydroelectric Operating Plans and Determination of Downstream Power Benefits for 1995-96

The Assured Operating Plan for 1995-96 and its associated Determination of Downstream Power Benefits are based on the same system regulation studies utilized for the Assured Operating Plan for 1994-95 and its Determination of Downstream Power Benefits.

The Entities believe that the minor changes necessary to update the 1994-95 studies would not significantly alter the results of the studies. In particular, after allowance for projected load increases, changes in conservation, energy exchanges and new independent resource additions, there would only be minor changes in the net hydro system load and thermal requirements. Therefore, neither the proposed operating rules that form the basis of the Assured Operating Plan for 1995-96, nor the associated Determination of Downstream Power Benefit studies are likely to change substantially from the 1994-95 counterparts.

The Determination of Downstream Power Benefits for 1995-96 does not affect the sale of the downstream benefits to the Columbia Storage Power Exchange. This determination is normally only made to provide a benchmark value and to determine the compensation for the reductions in benefits due to the Mica operating criteria. As the Mica operating criteria adopted for the Assured Operating Plan for 1995-96 are identical to those adopted for the Assured Operating Plan for 1994-95, the compensation for downstream benefit reductions is also identical to that computed in the Assured Operating Plan for 1994-95.

The studies to determine the impact of including firm energy shifting in the Assured Operating Plan, described in the report Options for Development of the Detailed Operating Plan for Operating Year 1995-96, were also based on the same system regulation studies utilized to determine the impact of including firm energy shifting in the Assured Operating Plan for 1994-95. As a result the options for development of the Detailed Operating Plan for 1995-96 are identical to the options for development of the Detailed Operating Plan 1994-95.

Use of the 1994-95 studies will allow the Entities to complete the development of the 1995-96 Assured Operating Plan and Determination of Downstream Power Benefits in a timely fashion. It will also allow the Entities more time to ensure that the 1996-97 studies fully reflect the latest agreements on principles and procedures for development of hydroelectric operating plans. These studies will be the basis for the last Determination of Downstream Power Benefits before the partial expiration of the sale of the Canadian Entitlement.

To facilitate development of the Detailed Operating Plan for 1995-96, it was decided to provide a complete documentation of the Assured Operating Plan for 1995-96 and its associated Determination of Downstream Power Benefits, even though much of the information is identical to that contained in the 1994-95 documents.

COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
FOR OPERATING YEAR 1995-96

HYDROELECTRIC OPERATING PLAN
ASSURED OPERATING PLAN
FOR OPERATING YEAR 1995-96

January 1991

1. Introduction

The treaty between Canada and the United States of America relating to the cooperative development of the water resources of the Columbia River Basin requires that each year an Assured Operating Plan be agreed to by the Entities for the operation of the Columbia River Treaty storage in Canada during the sixth succeeding year. This plan will provide to the Entities information for the sixth succeeding year for planning the power systems in their respective countries which are dependent on or coordinated with the operation of the Canadian storage projects.

This Assured Operating Plan was prepared in accordance with the Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans[1] and in accordance with the Entity Agreements on Principles[2] and on Changes to Procedures[3] for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies. It is based on criteria contained in Annex A and Annex B of the Columbia River Treaty,[4] Protocol,[5] Terms of Sale,[6] and the Columbia River Treaty Flood Control Operating Plan.[7]

The Assured Operating Plan consists of:

(a) The Operating Rule Curve for the whole of the Canadian storage, computed from the individual project Critical Rule Curves, Assured Refill Curves and Variable Refill Curves, and the individual project Upper Rule Curves.

(b) Operating Rules which specifically designate criteria for operation of the Canadian storage in accordance with the principles contained in the above references.

This Assured Operating Plan includes firm energy shifting as part of the United States optimum operation. This was incorporated in the studies as follows:

(a) The load in the first year of the critical period was maximized subject to draft constraints at each major reservoir. The maximum allowable drawdown at the end of July 1929 (the end of the first year of the critical period) was limited to 700 ksfd at Mica, 300 ksfd at Arrow and 143 ksfd at Duncan. In the 30-year studies, this higher load was served in each year that the reservoir system refilled prior to the start of the year.

(b) Energy shifted into the first year of the critical period was returned at uniform rates, excluding May, beginning in January of the second year of the critical period and continuing through until the end of the critical period.

(c) The shifted energy was used to eliminate energy deficits and to add to the initial Step I system firm energy capability in excess of system firm energy loads. Shifted energy in excess of firm load requirements was considered to increase the system sales to loads outside the Pacific Northwest Area and was further shaped into the fall months similar to the load it is expected to serve.

2. System Regulation Studies

In accordance with Annex A, Paragraph 7, of the Treaty, the Columbia River Treaty Operating Committee conducted system regulation studies reflecting Canadian storage operation for optimum generation in both Canada and the United States. Downstream power benefits were computed with the Canadian storage operation based on the operating rules specified herein. For this operation, there is a 2.0 MW decrease in the Canadian Entitlement to annual average usable energy and a 0.7 MW increase in the Entitlement to dependable capacity, compared to the operation for optimum generation in the United States alone. This is within the limits specified by the Treaty.

System Regulation Studies for the Assured Operating Plan were based on 1995-96 estimated loads and resources in British Columbia and in the United States Pacific Northwest System. The Entities have agreed that the 1995-96 Assured Operating Plan would be based on a 30-year streamflow period and an operating year of 1 August to 31 July. Historical flows for the period August 1928 through July 1958, modified to estimated 1994-95 conditions, were used.[9]

The Critical Rule Curve for these studies was determined from Bonneville Power Administration Study 96-41. The study indicated a 42-month critical period for the United States system resulting from the low flows during the period from 1 September 1928 through February 1932. It was assumed that all reservoirs, both in the United States and Canada, were full at the beginning of the critical period except where minimum release requirements made this impossible.

In the studies, individual project flood control criteria were followed. Flood Control and Variable Refill Criteria are based on historical inflow volumes. Although only 7.0 million acre-feet of usable storage at Mica is committed for power operation purposes under the Treaty, the Columbia River Treaty Flood Control Operating Plan provides for the full draft of the total 12 million acre-feet of usable storage at Mica in an on-call flood control situation.

3. Development of the Assured Operating Plan

This Assured Operating Plan was developed in accordance with Annex A, paragraph 7 of the Treaty and therefore was designed to produce optimum power generation at-site in Canada and downstream in Canada and the United States. The Mica Operating criteria were evaluated using the two tests described below.

(a) Determination of Optimum Generation in Canada and the United States

To determine whether optimum generation in both Canada and the United States was achieved in the system regulation studies, the firm energy capability, dependable peaking capability and average annual usable secondary energy were computed for both the Canadian and United States systems.

In the studies for the 1995-96 Assured Operating Plan, the Canadian storage operation was operated to achieve a weighted sum of the three quantities that was greater than the weighted sum achieved under an operation of Canadian storage for optimum generation in the United States alone.

The Columbia River Treaty Operating Committee agreed that for the 1995-96 Assured Operating Plan the three quantities would be assigned the following relative values:

Quantity	Relative Value
Firm energy capability (Avg. MW)	3
Dependable peaking capability (MW)	1
Average annual usable secondary energy (Avg. MW)	2

The three quantities were added after weighting on this basis and there was a net gain to the combined Canadian and United States systems with the study designed for optimum generation in Canada and the United States.

Table 1 shows the results from studies adopted for the 1995-96 Assured Operating Plan and from studies designed to achieve optimum generation in the United States.

(b) Maximum Permitted Reduction in Downstream Power Benefits

Separate system regulation studies were developed reflecting (i) Canadian storage operation for optimum generation in both Canada and the United States, using the Mica Project operating criteria described in Section 5(c), and (ii) Canadian storage operation for optimum generation in the United States alone. For these Mica Project operating criteria, there is a 2.0 MW decrease in entitlement to average annual energy, and 0.7 MW increase in entitlement to dependable capacity compared to an operation for optimum generation in the United States alone.

These reductions (and increases) are within the limits specified by the Treaty. The computations of these values are provided in the report Determination of Downstream Power Benefits for the Assured Operating Plan for 1995-96.

4. Operating Rule Curves

The operation of Canadian storage during the 1995-96 Operating Year shall be guided by an Operating Rule Curve for the whole of Canadian storage, Flood Control Storage Reservation Curves for the individual projects, and operating rules for specific projects. The Operating Rule Curve is derived from the various curves described below. These curves are first determined for the individual Canadian projects, which in turn are used to determine Operating Rules Curves for the individual projects which are then summed to yield the Composite Operating Rule Curve for the whole of Canadian storage. This is in accordance with the provision of Article VII(2) of the Protocol.

(a) Critical Rule Curve.

The Critical Rule Curve indicates the end-of-month storage content of Canadian storage during the critical period. It is designed to protect the ability of the United States system to serve firm load with the occurrence of flows no worse than those during the most adverse historical streamflow period. A tabulation of the Critical Rule Curves for Mica, Arrow and Duncan and the Composite Critical Rule Curve for the whole of Canadian storage is included in Table 3.

(b) Refill Curve.

The Refill Curve is a guide to operation of Canadian storage which defines the normal limit of storage draft to produce secondary energy in order to provide a high probability of refilling the storage. In general, the Operating Plan does not permit serving secondary loads at the risk of failing to refill storage and thereby jeopardizing the firm load carrying capability of the United States system or the Mica and Revelstoke generating plants during subsequent years. The end of the refill period is considered to be 31 July.

The Refill Curve is, in turn, defined by two curves as discussed below. In each case, adjustment should be made for water required for refill of upstream reservoirs when applicable.

(1) Assured Refill Curve.

The Assured Refill Curve indicates the end-of-month storage content required to assure refill of Canadian storage based on the 1930-31 water year, the system's second lowest historical volume of inflow during the 30-year record for the period January through July as measured at The Dalles, Oregon. A tabulation of the Assured Refill Curves for Mica, Arrow and Duncan is included as Table 4.

The schedule of outflows used in developing these Assured Refill Curves is the same as the Power Discharge Requirements used in computing the Variable Refill Curve discussed in 4(b)(2) below when The Dalles volume runoff is at 80 million acre-feet.

(2) Variable Refill Curve.

The Variable Refill Curve gives end-of-month storage contents for the period January through July required to refill Canadian storage during the refill period. They were based on historical inflow volumes and Power Discharge Requirements determined in accordance with the Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans.[1] In the system regulation studies the Power Discharge Requirement was made a function of the natural January - July runoff volume at The Dalles, Oregon. In those years when this volume was lower than 80 million acre-feet, the discharge used was that required to meet firm loads while refilling at 80 million acre-feet. In years when the runoff volume at The Dalles exceeded 95 million acre-feet, the Power Discharge Requirement was the project minimum outflow. For intermediate volumes, the Power Discharge Requirement used in computing the Variable Refill Curves was interpolated linearly between the values shown in Tables 5 - 7.

Variable Refill Curves for Mica, Arrow and Duncan for the 30 years of historical record are recorded in Tables 5 - 7. These illustrate the probable range of these curves based on historical conditions. In actual operation in 1995-96, the Power Discharge Requirements will be based on the forecast of unregulated runoff at The Dalles.

(c) Limiting Rule Curve.

The Limiting Rule Curves indicate month-end storage contents which must be maintained to guarantee the system meeting its firm load during the period January 1 - March 31 in the event that the Variable Refill Curves permit storage to be emptied and sufficient natural flow is not available to carry the load prior to the start of the freshet. Such rule curves shall limit the Variable Refill Curve to be no lower than the Limiting Rule Curve. The Limiting Rule Curve is developed for 1936-37 water conditions. Limiting Rule Curves for Mica, Arrow and Duncan are shown in Tables 5 - 7.

(d) Upper Rule Curve.

The Upper Rule Curves[10] indicate the end-of-month storage content to which each individual Canadian storage project shall be evacuated for flood control and other requirements. The Upper Rule Curves used in the studies were based upon Flood Control Storage Reservation Diagrams contained in the Columbia River Treaty Flood Control Operating Plan and analysis of system flood control simulations. Each Upper Rule Curve is constrained to be not lower than the Variable Refill Curve, except in those years in which the April-August unregulated volume of runoff for the Columbia River at The Dalles exceeds 120 million acre-feet, and Canadian storage is subject to on-call request. Flood control curves for Mica, Arrow and Duncan for the 30-year study period are shown on Tables 8 - 10; however, the tables do not reflect the constraint that the Upper Rule Curve not be lower than the Variable Refill Curve. Tables 9 and 10 reflect an assumed transfer of 2 million acre-feet of flood control storage space from Arrow to Mica. In actual operation, the Flood Control Storage Reservation Curves will be computed as outlined in the Flood Control Operating Plan, using the latest forecast of runoff available at that time.

(e) Definition of Operating Rule Curve.

During the period 1 August through 31 December, the Operating Rule Curve is defined by the Critical Rule Curve or the Assured Refill Curve, whichever is higher. The Critical Rule Curve for the first year of the critical period is used in the foregoing determination. During the period 1 January through 31 July, the Operating Rule Curve is defined by the higher of the Critical Rule Curve and the Assured Refill Curve; unless the Variable Refill Curve is lower than this value, then it is defined by the Variable Refill Curve. During the period 1 January through 31 March, it will not be lower than the Limiting Rule Curve. The Operating Rule Curve meets all requirements for flood control operation. Composite Operating Rule Curves for the whole of Canadian storage for all 30 years of historical record are included as Table 11 to illustrate the probable future range of these curves based on historical conditions.

5. Operating Rules

A 30-year System Regulation Study[8] was utilized to develop and test the operating rules and rule curves. It contains the agreed-upon operating constraints such as maximum and minimum project elevations, discharges, draft rates, etc. These constraints are included as part of this operating plan.

The following rules, used in the 30-year System Regulation Study[8], will apply to the operation of Canadian storage in the 1995-96 Operating Year.

(a) Operation Above Operating Rule Curve

The whole of the Canadian storage will be drafted to its Operating Rule Curve as required to produce optimum generation in Canada and the United States in accordance with Annex A, Paragraph 7, of the Treaty, subject to project physical characteristics, operating constraints, and the criteria for the Mica project listed in 5(c) below.

(b) Operation Below Operating Rule Curve

The whole of Canadian storage will be drafted below its Operating Rule Curve as required to produce optimum generation to the extent that a System Regulation Study determines that proportional draft below the Operating Rule Curves/Energy Content Curves is required to produce the hydro firm energy load carrying capability of the United States system as determined by the applicable Critical Period Regulation study. Energy Content Curves for United States reservoirs are equivalent to Operating Rule Curves. Proportional draft between rule curves will be determined as described in the Principles and Procedures.[1]

However, Mica Reservoir will continue to be operated in accordance with 5(c) below, so as to optimize generation at site and at Revelstoke as well as downstream in the United States. In the event the Mica operation results in more or less than the project's proportional share of draft from the whole of Canadian storage, compensating drafts will be made from Arrow to the extent possible.

(c) Mica Project Operation

Mica project operation will be determined by the end of previous period Arrow storage content as shown in Table 2. Mica monthly outflows will be increased above the values shown in the table in the months from October to June if required to avoid violation of the Upper Rule Curve.

Under this Assured Operating Plan, Mica storage releases in excess of 7 million acre-feet that are required to maintain the Mica outflows specified under this plan will be retained in the Arrow reservoir, subject to flood control and other project operating criteria at Arrow. The total combined storage draft from Mica and Arrow will not exceed 14.1 million acre-feet unless flood control criteria will not permit the additional Mica storage releases to be retained at Arrow. Should storage releases in excess of 14.1 million acre-feet be made, the target Mica operation will remain as specified in Table 2.

Revelstoke has been included in the 1995-96 Assured Operating Plan and has been operated as a run-of-river project.

6. Implementation

The Entities have agreed that each year a Detailed Operating Plan will be prepared for the immediately succeeding operating year. Such Detailed Operating Plans are made under authority of Article XIV 2.(k) of the Columbia River Treaty which states:

"...the powers and the duties of the entities include:

(k) preparation and implementation of detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under the plans referred to in Annexes A and B."

The Detailed Operating Plan for 1995-96 will reflect the latest available load, resource, and other pertinent data to the extent the Entities agree these data should be included in the plan.

The operating rules to be used in implementation of the Detailed Operating Plan for 1995-96 are generally the same as the operating rules described in this document. The data and criteria contained herein may be reviewed, and updated as agreed by the Entities, to form the basis for a Detailed Operating Plan for 1995-96. Failing agreement on updating the data and/or criteria, the Detailed Operating Plan for 1995-96 will include the rule curves, Mica operating criteria, and other data and criteria provided in this Assured Operating Plan. Actual operation during the 1995-96 Operating Year shall be guided by the Detailed Operating Plan.

The values used in the Assured Operating Plan studies to define the various rule curves were month-end values only. In actual day-to-day operation, it is necessary to operate in such a manner during the course of each month that these month-end values can be observed in accordance with the operating rules. Because of the normal variation of power load and streamflow during any month, straight line interpolation between the month-end points should not be assumed.

During the storage drawdown season, Canadian storage should not be drafted below its month-end point at any time during the month unless it can be conservatively demonstrated that sufficient inflow is available, in excess of the minimum outflow required to serve power demand, to refill the reservoir to its end-of-month value as required. During the storage evacuation and refill season, operation will be consistent with the Flood Control Operating Plan. When refill of Canadian storage is being guided by Flood Control Refill Curves,[7] such curves will be computed on a day-by-day basis using the residual volume-of-inflow forecasts depleted by the volume required for minimum outflow from each day through the end of the refill season.

REFERENCES

1 Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans dated May 1983.

2 Columbia River Treaty Entity Agreement on Principles for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, dated 28 July 1988.

3 Columbia River Treaty Entity Agreement on Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, dated 12 August 1988.

4 Treaty between Canada and the United States of America relating to Cooperative Development of the Water Resources of the Columbia River Basin dated 17 January 1961.

5 Protocol - Annex to Exchange of Notes dated 22 January 1964.

6 Terms of Sale - Attachment to Exchange of Notes dated 22 January 1964.

7 Columbia River Treaty Flood Control Operating Plan dated October 1972.

8 BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 96-41. This study is identical to the 30-year System Regulation Study 95-41, dated 9 July 1990.

9 Report on Modified Flows at Selected Sites, 1928 to 1968 for the 1980 and 2030 Level of Development, Columbia River and Coastal Basins, Columbia River Water Management Group, dated July 1983 and September 1988 respectively.

10 Summary of End-of-Month Reservoir Storage Requirement from Columbia River Flood Regulation Studies dated April 1973 and as updated March 1975.

TABLE 1

COMPARISON OF ASSURED OPERATING PLAN
STUDY RESULTS

Study 96-41 provides Optimum Generation in Canada and in the United States.
Study 96-11 provides Optimum Generation in the United States only.

	Study No. 96-41	Study No. 96-11	Net Gain	Weight	Value
1. Firm Energy Capability (Avg. MW)					
U.S. System[1]	12,160.8	12,165.2	-4.4		
Canada[2]	1,636.2	1,580.2	+56.0		
Total	13,797.0	13,745.4	+51.6	3	+154.8
2. Dependable Peaking Capacity (MW)					
U.S. System[3]	31,706.0	31,704.0	+2.0		
Canada[4]	3,500.0	3,484.0	+16.0		
Total	35,206.0	35,188.0	+18.0	1	+18.0
3. Average Annual Usable Secondary Energy (Avg. MW)					
U.S. System[5]	2,728.2	2,725.3	+2.9		
Canada[6]	132.9	171.2	-38.3		
Total	2,861.1	2,896.5	-35.4	2	-70.8
			Net Change in Value =		+102.0

Notes:

(1) U.S. System firm energy capability was determined over the U.S. system critical period beginning 1 September 1928 and ending 29 February 1932.

(2) Canadian system (Mica + Revelstoke) firm energy capability was determined over the Canadian system critical period beginning 1 October 1940 and ending 30 April 1946.

(3) U.S. system dependable peaking capability was determined from January 1937.

(4) Canadian system (Mica + Revelstoke) dependable peaking capability was determined from December 1944.

(5) U.S. system 30-year average secondary energy limited to secondary market.

(6) Canadian system (Mica and Revelstoke) 30-year average generation minus firm energy capability.

TABLE 2

MICA PROJECT OPERATING CRITERIA
ASSURED OPERATING PLAN

Month	End of Previous Period Arrow Storage Content (ksfd)	Target Operation: Period Average Outflow (cfs)	Target Operation: End-of-Period Treaty Content[1] (ksfd)	Minimum Outflow (cfs)	Minimum Treaty Content[2] (ksfd)
August 1-15	3 300 - FULL	-	3 456.2	10 000	0.0
	0 - 3 300	27 000			
August 16-31	2 400 - FULL	-	3 529.2	10 000	0.0
	0 - 2 400	27 000			
September	2 500 - FULL	-	3 529.2	10 000	0.0
	0 - 2 500	27 000			
October	2 900 - FULL	-	3 428.4	10 000	0.0
	2 400 - 2 900	18 000			
	0 - 2 400	27 000			
November	3 000 - FULL	22 000	-	10 000	1 056.2
	0 - 3 000	25 000			
December	3 000 - FULL	24 000	-	15 000	756.2
	2 000 - 3 000	29 000			
	0 - 2 000	34 000			
January	1 900 - FULL	27 000	-	15 000	356.2
	1 500 - 1 900	29 000			
	0 - 1 500	34 000			
February	600 - FULL	25 000	-	15 000	0.0
	0 - 600	27 000			
March	0 - FULL	25 000	-	15 000	0.0
April 1-15	0 - FULL	24 000	-	15 000	0.0
April 16-30	0 - FULL	14 000	-	10 000	0.0
May	510 - FULL	10 000	-	10 000	0.0
	0 - 510	15 000			
June	500 - FULL	10 000	-	10 000	0.0
	0 - 500	20 000			
July	2 300 - FULL	-	3 356.2	10 000	0.0
	0 - 2 300	27 000			

Notes:

(1) A maximum outflow of 34000 cfs will apply if the target end-of-period storage content is less than 3529.2 ksfd.

(2) Mica outflows will be reduced to minimum to maintain the reservoir above the minimum Treaty storage content. This will override any target flow.

COLUMBIA RIVER TREATY
CRITICAL RULE CURVES
END OF MONTH CONTENTS IN KSFD
1995-96 OPERATING YEAR

TABLE 3

MICA

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	3529.2	3529.2	3438.0	3295.0	3094.2	2669.5	1671.2	533.5	232.9	36.1	0.0	196.3	1576.4	2829.2
2ND YR	3085.5	3122.4	2996.3	2826.8	2189.0	1547.0	545.2	47.0	60.5	32.4	31.9	29.0	1237.7	2509.8
3RD YR	2825.9	3019.2	2976.8	2702.0	2270.0	1736.9	708.0	80.0	19.8	44.3	16.2	11.3	847.8	1458.7
4TH YR	1515.1	1501.3	1273.8	886.8	215.5	7.6	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

ARROW

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	3579.6	3579.6	3509.4	3334.5	3132.3	2482.4	1517.5	732.5	979.6	263.7	10.5	539.6	2327.7	3273.9
2ND YR	3215.1	3245.6	3236.5	2924.9	2190.2	1298.1	466.5	33.0	63.9	36.6	191.6	432.0	1770.7	2883.8
3RD YR	3111.9	3077.4	3100.1	2805.2	2317.0	1491.9	714.6	150.7	67.5	83.7	16.5	511.5	1168.8	1709.6
4TH YR	1707.9	1482.3	1402.8	1210.6	1296.8	769.9	345.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0

DUNCAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	705.8	705.8	633.9	544.8	315.5	209.4	49.0	41.0	38.2	5.7	2.5	117.6	389.6	571.0
2ND YR	481.6	386.2	254.9	60.0	1.2	2.7	1.3	0.1	1.0	2.4	0.1	0.5	99.3	12.4
3RD YR	2.3	37.3	47.7	2.5	2.7	3.4	1.4	0.0	1.4	0.0	7.5	56.6	51.5	34.5
4TH YR	0.9	1.0	2.1	4.8	0.8	2.5	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

COMPOSITE

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	7814.6	7814.6	7581.3	7174.3	6542.0	5361.3	3237.7	1307.0	1250.7	305.5	13.0	853.5	4293.7	6674.1
2ND YR	6782.2	6754.2	6487.7	5811.7	4380.4	2847.8	1013.0	80.1	125.4	71.4	223.6	461.5	3107.7	5406.0
3RD YR	5940.1	6133.9	6124.6	5509.7	4589.7	3232.2	1424.0	230.7	88.7	128.0	40.2	579.4	2068.1	3202.8
4TH YR	3223.9	2984.6	2678.7	2102.2	1513.1	780.0	356.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0

COLUMBIA RIVER TREATY
ASSURED REFILL CURVES
END OF MONTH CONTENTS IN KSFD
1995-96 OPERATING YEAR

TABLE 4

MICA

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1942.2	2525.2	3128.2	3306.6	3371.9	3388.4	3383.3	2895.9	2282.7	2007.9	1771.4	1773.5	2709.2	3529.2

ARROW

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
0.0	0.0	10.8	443.5	513.6	550.1	601.0	832.7	1126.4	1231.8	1325.9	2038.3	3136.6	3579.6

DUNCAN

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
93.8	164.7	231.0	261.7	279.2	290.4	300.6	298.6	300.3	307.5	292.2	390.5	556.4	705.8

DUNCAN VARIABLE REFILL CURVE (KSFD)
1995-96 OPERATING YEAR

TABLE 5

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							512.1	473.3	463.6	476.3	497.3	476.7	609.5	705.8
1929-30							510.1	471.3	461.3	473.8	507.7	497.6	620.9	,,
1930-31							454.7	417.1	410.6	429.8	459.1	446.0	609.5	,,
1931-32							1.2	1.6	0.8	0.0	35.6	112.3	447.9	,,
1932-33							,,	,,	,,	,,	0.0	0.0	314.3	,,
1933-34							,,	,,	,,	,,	45.9	144.5	488.3	,,
1934-35							119.4	95.4	109.7	135.4	194.7	228.8	479.4	,,
1935-36							110.0	84.2	85.6	111.3	171.9	228.0	527.8	,,
1936-37							458.2	420.6	412.7	427.1	451.5	438.1	591.7	,,
1937-38							1.2	1.6	0.8	16.2	91.5	168.0	471.8	,,
1938-39							309.6	275.0	270.5	293.9	339.6	357.2	592.5	,,
1939-40							298.3	263.5	266.3	299.3	346.0	359.3	581.2	,,
1940-41							377.9	341.9	340.9	372.4	422.1	437.2	604.6	,,
1941-42							235.9	209.2	218.5	241.4	295.5	327.5	546.3	,,
1942-43							121.4	96.5	105.7	131.9	199.9	280.8	505.0	,,
1943-44							534.5	494.8	489.9	503.6	524.7	510.1	639.5	,,
1944-45							455.4	417.8	413.8	430.5	454.2	438.5	597.9	,,
1945-46							1.2	1.6	0.8	0.0	0.0	56.8	440.9	,,
1946-47							,,	,,	,,	,,	9.3	100.4	453.6	,,
1947-48							,,	,,	,,	,,	43.8	118.7	464.5	,,
1948-49							173.8	147.8	153.6	175.7	233.2	294.2	565.4	,,
1949-50							1.2	1.6	0.8	0.0	61.4	126.9	408.6	,,
1950-51							,,	,,	,,	,,	11.1	92.4	439.6	,,
1951-52							5.5	,,	,,	24.4	95.7	178.3	484.5	,,
1952-53							4.9	,,	,,	23.7	93.2	156.5	450.9	,,
1953-54							1.2	,,	,,	0.0	0.0	18.9	381.9	,,
1954-55							,,	,,	,,	,,	57.3	116.7	391.5	,,
1955-56							,,	,,	,,	,,	0.0	66.8	437.5	,,
1956-57							,,	,,	,,	,,	48.2	119.6	501.4	,,
1957-58							,,	,,	,,	,,	0.0	57.2	453.6	,,
ECC LOWER LIMIT							1.2	1.6	0.8					
POWER DISCHARGE REQUIREMENTS IN CFS						80 MAF--	100	500	500	500	2000	2000	2500	2500
FOR JANUARY THROUGH JULY						90 MAF--	100	100	100	500	500	1000	1000	1000
VOLUME RUNOFF AT THE DALLES						95 MAF--	100	100	100	100	100	100	100	100

ARROW VARIABLE REFILL CURVE (KSFD)
1995-96 OPERATING YEAR

TABLE 6

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							2941.9	3023.9	3122.4	3436.2	3579.6	3372.4	3579.6	3579.6
1929-30							1325.8	1452.9	1644.2	2066.0	2930.6	2811.4	3452.9	,,
1930-31							1731.6	1847.4	1977.5	2372.3	3084.0	2630.7	3452.1	,,
1931-32							627.2	246.2	183.3	0.0	125.4	1107.0	2640.9	,,
1932-33							,,	,,	,,	,,	453.5	1291.2	2610.6	,,
1933-34							,,	,,	,,	,,	505.0	1713.6	3057.7	,,
1934-35							,,	,,	,,	,,	614.6	1217.2	2638.4	,,
1935-36							,,	,,	,,	,,	652.3	1381.6	2941.1	,,
1936-37							3232.4	3306.2	3402.7	3579.6	3579.6	3560.4	3579.6	,,
1937-38							627.2	246.2	183.3	228.0	962.6	1752.3	2911.1	,,
1938-39							1544.0	1665.0	1804.7	2207.1	3006.2	2730.4	3579.6	,,
1939-40							1074.3	1193.9	1407.1	1932.2	2813.3	2527.0	3528.0	,,
1940-41							2439.6	2535.6	2699.8	3164.8	3579.6	3579.6	3579.6	,,
1941-42							768.6	818.0	846.6	883.1	1480.5	1919.9	3004.9	,,
1942-43							1088.0	1095.8	1058.5	1207.8	2192.9	2899.6	3350.9	,,
1943-44							3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	,,
1944-45							3200.0	3274.7	3428.0	,,	,,	,,	,,	,,
1945-46							627.2	246.2	183.3	0.0	424.3	1314.8	2800.0	,,
1946-47							,,	,,	,,	,,	793.0	1660.2	2874.5	,,
1947-48							,,	,,	,,	,,	554.6	1374.6	2800.6	,,
1948-49							,,	,,	335.0	930.0	1911.3	2610.4	3579.6	,,
1949-50							,,	,,	183.3	0.0	534.3	1291.5	2496.0	,,
1950-51							,,	,,	,,	77.3	848.8	1628.0	3003.0	,,
1951-52							,,	,,	,,	78.7	792.7	1680.0	3107.1	,,
1952-53							,,	296.7	296.2	468.0	1370.2	1957.7	3066.6	,,
1953-54							,,	246.2	183.3	0.0	206.9	1009.7	2492.1	,,
1954-55							,,	,,	,,	,,	560.5	1246.3	2432.6	,,
1955-56							,,	,,	,,	,,	363.9	1339.5	2782.6	,,
1956-57							,,	,,	,,	,,	363.4	1172.5	3192.5	,,
1957-58							,,	,,	,,	,,	393.1	1226.1	2880.3	,,
ECC LOWER LIMIT							627.2	246.2	183.3					

		JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS IN CFS	80 MAF--	5000	15000	18000	22000	30000	45000	47000	48000
FOR JANUARY THROUGH JULY	90 MAF--	5000	5000	5000	5000	5000	8000	12000	15000
VOLUME RUNOFF AT THE DALLES	95 MAF--	5000	5000	5000	5000	10000	10000	35000	35000

MICA VARIABLE REFILL CURVE (KSFD)
1995-96 OPERATING YEAR

TABLE 7

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							3529.2	3529.2	3529.2	3529.2	3393.7	2713.2	3130.3	3529.2
1929-30							,,	3181.2	2513.2	2565.0	2556.3	2094.6	2846.2	,,
1930-31							,,	3450.2	2778.0	2789.9	2713.3	2115.2	2921.4	,,
1931-32							1131.3	1017.2	971.0	1210.9	1358.1	1390.7	2647.0	,,
1932-33							1066.2	956.3	927.5	1168.7	1293.4	1285.6	2483.5	,,
1933-34							317.6	157.4	122.2	436.8	666.2	1028.9	2736.0	,,
1934-35							679.4	493.1	384.2	684.6	852.3	857.1	2189.6	,,
1935-36							1260.9	966.4	710.8	944.1	1077.9	1072.2	2583.5	,,
1936-37							3529.2	3529.2	3529.2	3490.7	3385.2	2727.3	3162.7	,,
1937-38							1429.2	1311.7	1265.9	1488.1	1613.7	1617.8	2738.4	,,
1938-39							3529.2	3323.7	2665.3	2709.7	2654.8	2139.4	3154.4	,,
1939-40							,,	3065.5	2424.1	2480.7	2451.2	1929.7	2913.9	,,
1940-41							,,	3529.2	3001.9	3015.3	3007.1	2499.3	3144.3	,,
1941-42							1290.4	1081.4	932.8	1163.5	1312.4	1315.6	2534.4	,,
1942-43							2057.8	1927.1	1883.8	2051.3	2207.7	2256.9	2976.7	,,
1943-44							3529.2	3529.2	3529.2	3529.2	3464.1	2835.9	3301.3	,,
1944-45							,,	,,	,,	,,	3438.2	2761.7	3220.4	,,
1945-46							804.5	700.2	652.1	904.2	1051.8	1080.9	2641.4	,,
1946-47							982.2	874.1	855.1	1112.2	1273.9	1351.4	2712.0	,,
1947-48							907.3	797.9	763.7	1003.4	1136.8	1139.5	2597.8	,,
1948-49							2618.2	2475.8	2416.3	2544.0	2613.9	2544.2	3370.3	,,
1949-50							1229.7	1116.4	1058.6	1280.8	1407.3	1366.2	2409.6	,,
1950-51							1271.0	1156.9	1131.3	1364.4	1513.5	1488.7	2771.3	,,
1951-52							1642.4	1517.5	1466.9	1653.4	1762.4	1786.3	2918.0	,,
1952-53							1946.1	1817.8	1776.9	1952.3	2029.9	1944.9	2884.4	,,
1953-54							808.2	703.8	686.5	948.5	1087.4	1053.9	2381.3	,,
1954-55							1376.8	1255.7	1231.1	1461.9	1594.6	1555.9	2486.9	,,
1955-56							1128.3	1014.2	968.3	1199.5	1332.7	1384.7	2686.3	,,
1956-57							1290.8	1176.2	1145.1	1374.5	1501.3	1472.7	3016.3	,,
1957-58							1136.1	1024.8	1000.0	1245.4	1391.6	1369.6	2779.9	,,
ECC LOWER LIMIT							317.6	0.0	0.0					

		JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS IN CFS	80 MAF--	3000	20000	23000	23000	23000	28000	29000	30000
FOR JANUARY THROUGH JULY	90 MAF--	3000	3000	3000	3000	3000	5000	8000	10000
VOLUME RUNOFF AT THE DALLES	95 MAF--	3000	3000	3000	10000	10000	10000	20000	25000

TABLE 8

DUNCAN
FLOOD CONTROL STORAGE RESERVATION CURVES
1995-96 OPERATING YEAR
KSFD

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	705.8	705.8	705.8	705.8	705.8	504.1	418.3	340.8	340.8	348.1	360.5	443.7	574.4	705.8
1929-30	,,	,,	,,	,,	,,	,,	408.4	322.1	322.1	329.8	342.9	430.3	567.7	,,
1930-31	,,	,,	,,	,,	,,	,,	391.0	288.9	288.9	297.2	311.4	406.4	555.7	,,
1931-32	,,	,,	,,	,,	,,	,,	277.3	65.5	65.5	80.9	109.1	281.3	609.8	,,
1932-33	,,	,,	,,	,,	,,	,,	273.7	,,	,,	75.1	94.3	191.7	573.3	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	65.5	127.0	339.6	605.3	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	83.5	187.2	488.1	,,
1935-36	,,	,,	,,	,,	,,	,,	277.3	,,	,,	71.3	119.3	351.7	705.8	,,
1936-37	,,	,,	,,	,,	,,	,,	377.7	263.6	263.6	272.5	287.5	388.3	546.6	,,
1937-38	,,	,,	,,	,,	,,	,,	293.0	102.3	102.3	113.2	119.2	245.3	551.9	,,
1938-39	,,	,,	,,	,,	,,	,,	288.0	92.7	92.7	109.3	132.6	399.3	705.8	,,
1939-40	,,	,,	,,	,,	,,	,,	303.2	115.4	115.4	127.2	150.9	410.6	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	345.5	202.1	202.1	212.2	229.3	344.2	524.5	,,
1941-42	,,	,,	,,	,,	,,	,,	328.5	169.9	169.9	179.0	201.5	326.4	501.6	,,
1942-43	,,	,,	,,	,,	,,	,,	333.0	178.4	178.4	192.2	221.1	289.2	653.1	,,
1943-44	,,	,,	,,	,,	,,	,,	416.4	334.7	334.7	342.1	354.7	439.4	572.2	,,
1944-45	,,	,,	,,	,,	,,	,,	384.9	277.3	277.3	278.6	279.4	382.3	580.3	,,
1945-46	,,	,,	,,	,,	,,	,,	273.7	65.5	65.5	75.7	95.6	322.3	647.5	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	77.1	102.0	314.0	629.6	,,
1947-48	,,	,,	,,	,,	,,	,,	277.3	,,	,,	65.5	65.5	300.5	705.8	,,
1948-49	,,	,,	,,	,,	,,	,,	371.1	251.0	251.0	256.9	277.0	434.3	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	273.7	65.5	65.5	65.5	65.5	184.0	525.3	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	285.1	534.2	,,
1951-52	,,	,,	,,	,,	,,	,,	277.3	,,	,,	,,	67.4	92.4	255.0	,,
1952-53	,,	,,	,,	,,	,,	,,	273.7	,,	,,	71.9	84.7	234.6	522.7	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	73.2	84.1	237.1	547.6	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	71.9	80.9	154.5	488.8	,,
1955-56	,,	,,	,,	,,	,,	,,	277.3	,,	,,	65.5	84.7	266.6	585.4	,,
1956-57	,,	,,	,,	,,	,,	,,	273.7	,,	,,	74.5	89.9	376.1	655.8	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	77.1	96.3	359.4	705.8	,,

TABLE 9

ARROW
FLOOD CONTROL STORAGE RESERVATION CURVES
1995-96 OPERATING YEAR
KSFD

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	3579.6	3579.6	3579.6	3453.6	3453.6	3075.4	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	3579.6
1929-30	,,	,,	,,	,,	,,	,,	2998.3	2928.3	2851.2	2870.1	2902.9	3082.8	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	2371.6	1712.7	1008.4	1016.1	1126.6	2224.6	,,	,,
1932-33	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1008.4	1036.6	1761.7	3034.5	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1784.9	2327.4	3579.6	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	1725.7	3034.5	,,
1935-36	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1070.1	1373.5	2134.6	3579.6	,,
1936-37	,,	,,	,,	,,	,,	,,	2940.8	2818.8	2684.1	2707.4	2755.8	3266.2	,,	,,
1937-38	,,	,,	,,	,,	,,	,,	2363.5	1720.2	1008.4	1082.9	1278.3	1831.2	3147.6	,,
1938-39	,,	,,	,,	,,	,,	,,	2584.5	2141.3	1650.3	1719.8	1843.3	2661.3	3579.6	,,
1939-40	,,	,,	,,	,,	,,	,,	2793.4	2529.4	2247.3	2287.2	2380.5	2913.4	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	,,	,,
1941-42	,,	,,	,,	,,	,,	,,	2363.5	1720.2	1008.4	1064.9	1149.8	1934.0	,,	,,
1942-43	,,	,,	,,	,,	,,	,,	,,	,,	,,	1111.2	1322.0	1440.3	2389.1	,,
1943-44	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	,,
1944-45	,,	,,	,,	,,	,,	,,	2582.9	2138.0	1645.5	1672.5	1744.1	2368.8	3347.5	,,
1945-46	,,	,,	,,	,,	,,	,,	2363.5	1720.2	1008.4	1072.6	1242.3	2201.4	3579.6	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	1075.2	1360.6	2147.4	,,	,,
1947-48	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1036.6	1183.2	2216.8	,,	,,
1948-49	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1144.6	1376.0	2494.5	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	1008.4	1113.8	2232.3	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1355.5	3337.9	,,
1951-52	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1070.1	1345.2	1792.6	3013.9	,,
1952-53	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1057.2	1172.9	1476.3	,,	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1134.3	1628.0	1898.0	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	1075.2	1090.6	1653.7	3224.8	,,
1955-56	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1008.4	1216.6	1990.6	2993.4	,,
1956-57	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1077.8	1224.3	2651.4	3579.6	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	1046.9	1190.9	2242.5	,,	,,

TABLE 10

MICA
FLOOD CONTROL STORAGE RESERVATION CURVES
1995-96 OPERATING YEAR
KSFD

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	3529.2	3529.2	3529.2	3428.4	3428.4	3428.4	3385.7	3347.2	3304.6	3304.6	3304.6	3369.1	3447.9	3529.2
1929-30	,,	,,	,,	,,	,,	,,	3352.6	3284.4	3208.7	3208.7	3208.7	3300.7	3413.2	,,
1930-31	,,	,,	,,	,,	,,	,,	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	,,
1931-32	,,	,,	,,	,,	,,	,,	3105.7	2803.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1932-33	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	,,	,,	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1935-36	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	,,	,,	,,
1936-37	,,	,,	,,	,,	,,	,,	3330.6	3242.3	3144.5	3144.5	3144.5	3323.3	3398.4	,,
1937-38	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1938-39	,,	,,	,,	,,	,,	,,	3193.8	2981.4	2746.8	2746.8	2746.8	2971.4	3246.0	,,
1939-40	,,	,,	,,	,,	,,	,,	3274.3	3130.5	2976.4	2976.4	2976.4	3135.1	3329.1	,,
1940-41	,,	,,	,,	,,	,,	,,	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	,,
1941-42	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1942-43	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1943-44	,,	,,	,,	,,	,,	,,	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	,,
1944-45	,,	,,	,,	,,	,,	,,	3193.1	2980.2	2745.0	2745.0	2745.0	2970.0	3245.3	,,
1945-46	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1947-48	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	,,	,,	,,
1948-49	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	,,	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1951-52	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	,,	,,	,,
1952-53	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	,,	,,	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1955-56	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	2695.5	3172.7	,,
1956-57	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	2781.5	3149.6	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,

COLUMBIA RIVER TREATY
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF MONTH CONTENTS IN KSFD
1995-96 OPERATING YEAR

TABLE 11

FLOW YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7581.3	7185.9	6819.7	6161.2	5201.4	4027.2	3709.4	3547.2	3389.5	4202.3	6402.2	7814.6
1929-30	,,	,,	,,	,,	,,	,,	5009.7	,,	,,	,,	,,	,,	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	5201.4	,,	,,	,,	,,	,,	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	1759.7	1265.0	1155.1	1210.9	1519.1	2610.0	5735.8	,,
1932-33	,,	,,	,,	,,	,,	,,	1694.6	1204.1	1111.6	1168.7	1746.9	2576.8	5408.4	,,
1933-34	,,	,,	,,	,,	,,	,,	946.0	405.2	306.3	436.8	1217.1	2887.0	6255.2	,,
1934-35	,,	,,	,,	,,	,,	,,	1426.0	834.7	677.2	820.0	1661.6	2303.1	5307.4	,,
1935-36	,,	,,	,,	,,	,,	,,	1998.1	1296.8	979.7	1055.4	1902.1	2681.8	6052.4	,,
1936-37	,,	,,	,,	,,	,,	,,	5201.4	4027.2	3709.4	3547.2	3389.5	4202.3	6402.2	,,
1937-38	,,	,,	,,	,,	,,	,,	2057.6	1559.5	1450.0	1732.3	2667.8	3538.1	6092.1	,,
1938-39	,,	,,	,,	,,	,,	,,	5201.4	4003.6	3679.6	3533.6	3389.5	4169.0	6402.2	,,
1939-40	,,	,,	,,	,,	,,	,,	4755.9	3992.1	3675.4	3539.0	,,	4171.1	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	5201.4	4027.2	3709.4	3547.2	,,	4202.3	,,	,,
1941-42	,,	,,	,,	,,	,,	,,	2294.9	2108.6	1997.9	2288.0	2930.5	3563.0	6085.6	,,
1942-43	,,	,,	,,	,,	,,	,,	3267.2	2856.3	3048.0	3347.6	3297.2	4092.6	6350.8	,,
1943-44	,,	,,	,,	,,	,,	,,	5201.4	4027.2	3709.4	3547.2	3389.5	4202.3	6402.2	,,
1944-45	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1945-46	,,	,,	,,	,,	,,	,,	1432.9	948.0	836.2	904.2	1476.1	2452.5	5882.3	,,
1946-47	,,	,,	,,	,,	,,	,,	1610.6	1121.9	1039.2	1112.2	2076.2	3112.0	6037.3	,,
1947-48	,,	,,	,,	,,	,,	,,	1535.7	1045.7	947.8	1003.4	1735.2	2632.8	5862.9	,,
1948-49	,,	,,	,,	,,	,,	,,	3419.2	2869.8	2771.3	3113.6	3330.5	4106.0	6402.2	,,
1949-50	,,	,,	,,	,,	,,	,,	1858.1	1364.2	1242.7	1280.8	2003.0	2784.6	5314.2	,,
1950-51	,,	,,	,,	,,	,,	,,	1899.4	1404.7	1315.4	1441.7	2373.4	3209.1	6151.8	,,
1951-52	,,	,,	,,	,,	,,	,,	2275.1	1765.3	1651.0	1756.5	2650.8	3631.8	6300.8	,,
1952-53	,,	,,	,,	,,	,,	,,	2578.2	2116.1	2073.9	2444.0	3190.5	3887.7	6226.7	,,
1953-54	,,	,,	,,	,,	,,	,,	1436.6	951.6	870.6	948.5	1294.3	2082.5	5255.3	,,
1954-55	,,	,,	,,	,,	,,	,,	2005.2	1503.5	1415.2	1461.9	2212.4	2918.9	5311.0	,,
1955-56	,,	,,	,,	,,	,,	,,	1756.7	1262.0	1152.4	1199.5	1696.6	2791.0	5906.4	,,
1956-57	,,	,,	,,	,,	,,	,,	1919.2	1424.0	1329.2	1374.5	1912.9	2764.8	6347.2	,,
1957-58	,,	,,	,,	,,	,,	,,	1764.5	1272.6	1184.1	1245.4	1784.7	2652.9	6043.1	,,

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 1995-96

**DETERMINATION OF DOWNSTREAM POWER BENEFITS
FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 1995-96**

January 1991

1. Introduction

The treaty between Canada and the United States of America relating to the cooperative development of the water resources of the Columbia River Basin requires that downstream power benefits from the operation of Canadian Treaty storage be determined in advance by the two Entities. The purpose of this document is to describe the results of those downstream power benefit computations developed from the 1995-96 Assured Operating Plan (AOP).

The procedures followed in the benefit studies are those provided in Annex A, Paragraph 7, and Annex B of the Treaty; in Articles VIII, IX, and X of the Protocol; and in the document, "Columbia River Treaty Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans" (POP), dated May 1983, and as clarified in the Entity Agreements, signed July 28 and August 12, 1988, on Principles and on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies (1988 Entity Agreements).

The Canadian Entitlement Benefits were computed from the following studies:

Step I - based on the total United States of America planned hydro and thermal system with 15-1/2 million acre-feet (maf) of Canadian storage operated for optimum power generation in both countries.

Step II - based on the United States base hydro and thermal system with 15-1/2 maf of Canadian storage operated for optimum power generation in both countries.

Step III - based on the United States base hydro and thermal system operated for optimum power generation in the United States.

As part of the determination of downstream power benefits for the operating year 1995-96, separate determinations were carried out relating to:

i) the limit of year-to-year change in benefits attributable to the operation of Canadian Treaty storage in operating plans designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States of America, and

ii) the decrease in downstream power benefits due to the operation of Canadian Treaty storage for optimum power generation at-site in Canada and downstream in Canada and the United States of America, instead of operation of Canadian Treaty storage for optimum power generation in the United States of America only.

2. Results of Canadian Entitlement Computations

The Canadian Entitlement to the downstream power benefits in the United States of America attributable to operation in accordance with Treaty Annex A, Paragraph 7, for optimum power generation in Canada and the United States of America, which is one-half the total computed downstream power benefits, was computed to be (See Table 1):

Dependable Capacity	=	1,183.4 MW
Average Annual Energy	=	653.2 MW

3. Computation of Maximum Allowable Reduction in Downstream Power Benefits

In accordance with the Treaty Annex A, Paragraph 7 and Part III, Paragraph 15c(2) of POP, the computation of the maximum allowable reduction in downstream power benefits and the resulting minimum permitted Canadian Entitlement to downstream power benefits for the 1995-96 operating year are based on the formula X - (Y - Z).

The quantities X, Y, and Z, expressed in terms of entitlement to downstream power benefits, are computed as follows:

X is one half of the downstream power benefits derived from the previous year's 95-42 and 95-13 studies.

Y is one half of the downstream power benefits derived from the previous year's 95-12 and 95-13 studies.

Z is one half of the downstream power benefits derived from the present year's 96-22 and 96-13 studies.

The purpose of this formula is to set a lower limit on the Canadian Entitlement by accumulating the annual reductions resulting from reoperation of Canadian storage as well as the reductions caused by year to year changes in data and by removal of 0.5 MAF storage.

The quantities X and Y were computed in the 1994-95 DDPB. The quantity Z which is computed from one-half of the downstream power benefits determined for 15 maf of the Canadian Treaty storage operated for optimum power generation in the United States of America, is computed in Table 1.

The computation of the formula X - (Y - Z) is as follows:

Dependable Capacity	=	1,183.4	-	(1,182.7	-	1,159.2)	=	1,159.9 MW
Average Annual Energy	=	653.2	-	(655.2	-	650.0)	=	648.0 MW

The computed Canadian Entitlement exceeds these amounts.

4. Effect on Sale of Canadian Entitlement

The Canadian Entitlement to downstream power benefits for operating year 1995-96 was sold to the United States of America under the Canadian Entitlement Purchase Agreement dated 13 August 1964. The studies developed for this sale included the assumption of operation of Treaty storage for optimum power generation downstream in the United States of America only. The Canadian Entitlement determined from the 1995-96 Assured Operating Plan for this condition would have been:

Dependable Capacity	=	1,182.7 MW
Average Annual Energy	=	655.2 MW

Since the 1995-96 Assured Operating Plan was in fact designed to achieve optimum power generation at-side in Canada and downstream in Canada and the United States of America, Section 7 of the Agreement requires that "any reduction in the Canadian Entitlement resulting from action taken pursuant to paragraph 7 of Annex A of the Treaty shall be determined in accordance with Subsection (3) of Section 6 of this Agreement." A comparison with the Canadian Entitlement to downstream power benefits shown above indicates a decrease in Canadian Entitlement of 2.0 MW of average annual usable energy, and an increase of 0.7 MW in dependable capacity.

Accordingly, the Entities are agreed that the United States Entity is entitled to receive 2.0 MW of energy, but not entitled to receive any dependable capacity during the period 1 April 1995 through 31 March 1996, from B.C. Hydro & Power Authority, in accordance with Sections 7 and 10 of the Canadian Entitlement Purchase Agreement dated 13 August 1964.

5. Summary of Canadian Entitlement Computations

The following Tables and Chart summarize the study results:

Table 1. Computation of Canadian Entitlement for 1995-96 Assured Operating Plan:

A. Optimum Generation in Canada and the U.S.
B. Optimum Generation in the U.S. Only
C. Optimum Generation in the U.S. and a 1/2 Million Acre-Feet Reduction in Total Canadian Treaty Storage

The essential elements used in the computation of the Canadian Entitlement to downstream power benefits, the minimum permitted downstream power benefits, and the reduction in downstream power benefits attributable to the operation of Canadian Treaty storage for optimum power generation in the United States of America only, are shown on this table.

Table 2. Summary of Power Regulations from 1995-96 Assured Operating Plan for the Computation of Canadian Entitlement to Downstream Power Benefits

This table summarizes the results of the Step I, II, and III power regulation studies for each project and the total system.

Table 3. Determination of Displaceable Thermal Market for 1995-96 Assured Operating Plan

This table shows the computation of the potential thermal displacement market for the downstream power benefit determination of usable energy. The potential thermal displacement market was limited to the existing and scheduled thermal energy capability after allowance for reserves, minimum thermal generation, and reductions for the thermal resources used outside the PNW area. Additional lines in the table show the energy shifted into the first year to eliminate deficits and to increase the firm hydro surplus in the fall. In years when reservoirs do not refill, thermal resources were added to eliminate deficits and to provide energy for return of shift.

Table 4. Determination of Loads for 1995-96 Step I, II, and III Studies for Assured Operating Plan

This table shows the computation of the Step I, II, and III loads and the effect of including shifted firm energy in the Step I and II studies. The monthly loads for Step II and III studies have the same ratio between each month and the annual average as does the Pacific Northwest (PNW) area load. The PNW area firm loads on this table were based on the current forecast data. The Grand Coulee pumping load is also included in this estimate. The method for computing the firm load for the Step II and III studies is described in POP and clarified in the 1988 Entity Agreements.

Chart 1. 1995-96 Determination of Downstream Power Benefits 30-Year Hydro Generation

This chart shows duration curves of the hydro generation from the Step II and III studies and graphically illustrates the change in the portion of secondary energy that is usable for thermal displacement due to operation of Treaty storage. Secondary energy is the energy capability each month which exceeds the firm hydro loads shown in Table 3. The usable secondary energy in average megawatts for the Step II and III studies is computed in accordance with Annex B, Paragraphs 3(b) and 3(c), as the portion of secondary energy which can displace thermal resources used to meet PNW area loads plus the other usable secondary generation. The Entities have agreed that "the other usable secondary" is computed on the basis of 40 percent of the remainder after thermal displacement.

6. Summary of Changes From Previous Year

Data from the six most recent Assured Operating Plans and their associated Determination of Downstream Power Benefits is summarized in Tables 5 and 6.

Since the Assured Operating Plan for 1995-96 and its associated DDPB are based on the same system regulation studies utilized for the Assured Operating Plan and DDPB for 1994-95, there are no changes in project data, streamflows, system loads, energy exchanges, operating procedures or energy shifting.

7. <u>Firm Energy Shifting</u>

The following is a summary of how firm energy shifting was included in the operating plan studies.

In the Step I studies, the hydro system was operated to maximize its first-year firm energy load carrying capability while the system was drafted to July 1929 refill constraints. This first-year firm energy load carrying capability was served in all years that the reservoir system refilled. This operation shifts hydro energy production from later years of the critical period into the first year.

This shifted firm energy was shaped into periods consistent with the expected use of the energy. The first use (139 aMW) was to eliminate firm energy deficits during the period September through July. The balance was used to increase the firm surplus during the period September through December by 1032 aMW.

In later years of the critical period, and in years subsequent to failure to refill by July 31, 237 aMW of combustion turbine energy was used to reduce the need for hydro generation. This return of shifted firm energy occurred in the following streamflow conditions:

January 1930 through February 1932, excluding Mays
January 1938 through July 1938, excluding Mays
January 1942 through July 1942, excluding Mays
January 1944 through July 1946, excluding Mays

According to the 1988 Entity Agreements, the return energy should be at uniform rates throughout the later years of the critical period. Therefore energy return should begin in August and include Mays for Step I studies. This will be included in future studies.

In the Step II study, firm energy was shifted into the first year and shaped to the monthly shape of the PNW area load, consistent with the 1988 Entity Agreements. Table 3 provides the monthly shift amounts. This is the first year that the shifted firm energy was shaped in the prescribed manner.

Shifted firm energy was returned in years subsequent to a failure to refill, at the same 237 aMW rate. This occurred during the following periods:

August 1930 through April 30 1931
January 1937 through April 15 1937
August 1945 through April 30 1945

For the Step II and III computation of surplus energy limited to thermal displacement market, the years shifted and returned were carried over from Step I. This was done so operating procedures would be consistent among Step I, II and III.

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TABLE 1

COMPUTATION OF CANADIAN ENTITLEMENT FOR
1995-96 ASSURED OPERATING PLAN

A. Optimum Power Generation in Canada and the U.S. (From 96-42)
B. Optimum Power Generation in the U.S. Only (From 96-12)
C. Optimum Power Generation in the U.S. and a 1/2 Million Acre-Feet Reduction in Total Canadian Treaty Storage (From 96-22)

Determination of Dependable Capacity Credited to Canadian Storage - MW

	(A)	(B)	(C)
Step II - Critical Period Avg. Generation 1/	8,892.9	8,891.8	8,856.6
Step III - Critical Period Avg. Generation 2/	7,113.5	7,113.5	7,113.5
Gain Due to Canadian Storage	1,779.4	1,778.3	1,743.1
Average Critical Period Load Factor in % 3/	75.18	75.18	75.18
Dependable Capacity Gain 4/	2,366.9	2,365.4	2318.5
Canadian Share of Dependable Capacity 5/	1,183.4	1,182.7	1,159.2

Determination of Increase in Average Annual Usable Energy - Average MW

Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Annual Firm Hydro Energy 6/	8,928.3	8,927.2	8,892.6
Thermal Replacement Energy 7/	1,422.3	1,416.1	1,435.3
Other Usable Secondary Energy 8/	421.0	432.2	437.3
System Annual Average Usable Energy	10,771.6	10,775.5	10,765.2
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6,401.4	6,401.4	6,401.4
Thermal Replacement Energy 7/	2,123.8	2,123.8	2,123.8
Other Usable Secondary Energy 8/	940.0	940.0	940.0
System Annual Average Usable Energy	9,465.2	9,465.2	9,465.2
Average Annual Usable Energy Gain 9/	1,306.4	1,310.3	1,300.0
Canadian Share of Avg. Annual Energy Gain 5/	653.2	655.2	650.0

1/ Step II values were obtained from the Shift 96-42, 96-12, and 96-22 studies, respectively.
2/ Step III values were obtained from the Shift 96-13 study.
3/ Critical period load factor from Table 3.
4/ Dependable Capacity Gain credited to Canadian storage equals gain in critical period average generation divided by the average critical period load factor.
5/ One-half of Dependable Capacity or Usable Energy Gain.
6/ From 30-year average firm load served.
7/ Avg. secondary generation limited to Potential Thermal Displacement market.
8/ Forty percent (40%) of the remaining secondary energy.
9/ Difference between Step II and Step III Annual Average Usable Energy.

TABLE 2

SUMMARY OF POWER REGULATIONS
FROM 1995-96 ASSURED OPERATING PLAN

PROJECTS	BASIC DATA: NUMBER OF UNITS	BASIC DATA: NOMINAL INSTALLED PEAKING CAPACITY MW	STEP I: USABLE STORAGE 1000 AF	STEP I: JANUARY PEAKING CAPABILITY MW	STEP I: CRITICAL PERIOD AVERAGE GENERATION MW	STEP II: USABLE STORAGE 1000 AF	STEP II: JANUARY PEAKING CAPABILITY MW	STEP II: CRITICAL PERIOD AVERAGE GENERATION MW	STEP II: 30 YEAR AVERAGE ANNUAL GENERATION MW	STEP III: USABLE STORAGE 1000 AF	STEP III: JANUARY PEAKING CAPABILITY MW	STEP III: CRITICAL PERIOD AVERAGE GENERATION MW	STEP III: 30 YEAR AVERAGE ANNUAL GENERATION MW
HYDRO RESOURCES													
CANADIAN													
Mica			7,000			7,000							
Arrow			7,100			7,100							
Duncan			1,400			1,400							
Subtotal			15,500			15,500							
BASE SYSTEM													
Hungry Horse	4	328	3,161	291	94	3,008	185	111	102	3,008	328	192	104
Kerr	3	160	1,219	149	113	1,219	147	102	117	1,219	151	143	115
Thompson Falls	6	40	0	40	38	0	40	38	37	0	40	40	36
Noxon Rapids	5	554	231	536	148	0	554	134	202	0	554	171	202
Cabinet Gorge	4	230	0	230	99	0	230	87	117	0	230	108	117
Albeni Falls	3	49	1,155	29	27	1,155	31	26	27	1,155	40	28	29
Box Canyon	4	74	0	71	46	0	72	44	48	0	70	55	47
Grand Coulee	24+3SS	6,684	5,185	6,382	2,000	5,072	6,358	1,749	2,348	5,072	5,668	1,191	2,246
Chief Joseph	27	2,614	0	2,614	1,123	0	2,614	1,022	1,371	0	2,614	747	1,296
Wells	10	820	0	820	392	0	820	366	452	0	820	273	418
Rocky Reach	11	1,267	0	1,267	563	0	1,267	526	677	0	1,267	392	634
Rock Island	18	544	0	544	274	0	544	257	323	0	544	189	295
Wanapum	10	986	0	986	504	0	986	477	591	0	986	345	535
Priest Rapids	10	912	0	912	500	0	912	473	565	0	912	350	510
Brownlee	5	675	975	675	225	974	675	296	290	974	675	266	290
Oxbow	4	220	0	220	93	0	220	117	118	0	220	120	118
Ice Harbor	6	693	0	693	217	0	693	231	300	0	693	192	300
McNary	14	1,127	0	1,127	655	0	1,127	631	793	0	1,127	503	745
John Day	16	2,484	535	2,484	928	0	2,484	905	1,228	0	2,484	716	1,193
The Dalles	22+2F	2,074	0	2,074	738	0	2,074	717	976	0	2,074	584	957
Bonneville	18+2F	1,147	0	1,147	556	0	1,147	546	676	0	1,147	458	646
Kootenay Lake	0	0	673	0	0	673	0	0	0	673	0	0	0
Chelan	2	54	677	51	36	676	51	38	45	676	52	51	42
Coeur d'Alene Lake	0	0	223	0	0	223	0	0	0	223	0	0	0
Total Base System Hydro		23,736	29,535	23,342	9,369	28,500	23,231	8,893	11,403	13,000	22,696	7,114	10,875

ADDITIONAL STEP I PROJECTS									
Libby	5	604	4,980	545	180				
Boundary	6	1,055	0	855	368				
Spokane River Plants	24	156	104	155	91				
Hells Canyon	3	450	0	450	180				
Dworshak	3	460	2,015	460	178				
Lower Granite	6	932	0	932	215				
Little Goose	6	932	0	932	216				
Lower Monumental	6	932	0	932	204				
Pelton, Rereg., and Round Butte	7	423	274	419	123				
Subtotal		5,944	7,373	5,680	1,755				
THERMAL RESOURCES 1/									
Small Existing Thermal Plants 2/				1,656	542				
Centralia #1 & #2				1,280	1,146				
Jim Bridger #1, #2, #3, & #4				2,021	1,667				
Colstrip #1,#2,#3,#4				1,297	1,006				
Trojan				1,104	797				
Boardman				530	404				
Valmy				242	199				
WNP #2				1,095	731				
Total Thermal Resources				9,225	6,492	9,225	6,516	9,225	6,618
RESERVES 3/				(2,394)	0	(1,926)	0	(1,622)	0
TOTAL RESOURCES				35,853	17,616	30,530	15,409	30,299	13,732
LOADS									
ESTIMATED LOAD PACIFIC NORTHWEST AREA 4/				29,925	19,021	24,069	15,409	20,273	13,732
Firm Exports				1305	889				
Surplus Firm Exports				0	219				
Firm Imports				(1,018)	(212)				
Miscellaneous Contracts				(275)	(311)				
Other Coordinated Hydro		3,183	5,576	(2,718)	(1,037)				
Independent Hydro Resources		1,988	4,342	(1,489)	(821)				
Estimated Hydro Maintenance				1,561	11				
Added Conservation/Resources				0	(143)				
TOTAL STEP I LOADS				27,291	17,616				
SURPLUS				8,562	0	6,461	0	10,026	0
CRITICAL PERIOD Starts				September 1, 1928		September 1, 1943		November 1, 1936	
Ends				February 29, 1932		April 30, 1945		April 30, 1937	
Length (Months)				42 Months		20 Months		6 Months	
Study Identification				95-41		95-42		95-13	

1/ Thermal energy capabilities are based on an annual plant factor of 60 percent the first full year of operation and 75 percent thereafter unless specified differently by project owner. These annual plant factors include deductions for energy resources and scheduled maintenance.
2/ Sm-Existing Thermal Plant also includes Combustion Turbines.
3/ Peak reserves are 8 percent of peak load from Table 3; energy reserve deductions have been included in thermal plant energy capability.
4/ Step II or III Peak Load is equal to the Step II or III Annual Average Load multiplied by the ratio of the PNW Area January Peak Load to the Annual Average Load.

TABLE 3

DETERMINATION OF DISPLACEABLE THERMAL MARKET
FOR 1995–96 ASSURED OPERATING PLAN
(Energy in Average MW)

	Aug 1–15	Aug 16–31	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	March	Apr 1–15	Apr 16–30	May	June	July	Annual Average
THERMAL RESOURCES															
1. Total PNW Thermal Resources	6907.0	6907.0	6684.0	7095.0	7141.0	7140.0	7149.0	6953.0	6114.0	6068.0	4343.0	3764.0	5739.0	6949.0	6402.0
1a. Added Thermal	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	
2. Minimum Thermal Generation	1666.0	1666.0	1515.0	1703.0	1831.0	1831.0	1831.0	1740.0	1502.0	1419.0	1315.0	1176.0	1364.0	1689.0	1601.0
3. Displaceable PNW Thermal Resources	5616.6	5616.6	5544.6	5767.6	5685.6	5684.6	5693.6	5588.6	4987.6	5044.6	3403.6	2963.6	4750.6	5635.6	5176.6
4. Displaceable PSW Thermal Imports	0.0	0.0	0.0	0.0	0.0	0.0	143.0	285.0	285.0	285.0	0.0	0.0	0.0	0.0	69.9
5. Total Displaceable Thermal Resources	5616.6	5616.6	5544.6	5767.6	5685.6	5684.6	5836.6	5873.6	5272.6	5329.6	3403.6	2963.6	4750.6	5635.6	5246.5
SYSTEM SALES															
6. Total Exports/Incl Exchanges	1086.0	1086.0	1047.0	781.0	705.0	749.0	746.0	727.0	730.0	821.0	885.0	1046.0	1146.0	1229.0	904.6
7. Total Export Exchanges	377.0	377.0	367.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	116.0	367.0	375.0	196.6
8. Exports w/o Exchanges	709.0	709.0	680.0	673.0	597.0	641.0	638.0	619.0	622.0	713.0	777.0	930.0	779.0	854.0	708.1
9. Additional Net Exchange Exports	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0
10. Net Exchanges/Exports	810.0	810.0	781.0	774.0	698.0	742.0	739.0	720.0	723.0	814.0	878.0	1031.0	880.0	955.0	
11. Firm Surplus Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3000.0	0.0	0.0	
11a. Added Thermal	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	375.6	
12. Total System Sales	1185.6	1185.6	1156.6	1149.6	1073.6	1117.6	1114.6	1095.6	1098.6	1189.6	1253.6	4406.6	1255.6	1330.6	1439.5
SHIFT															
13a. Deficit	0.0	0.0	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	
13b. Shift	0.0	0.0	1171.2	1171.2	1171.2	1171.2	138.9	138.9	138.9	138.9	138.9	138.9	138.9	138.9	99.0
14. Total System Sales w/shift	1185.6	1185.6	2186.9	2181.9	2105.9	2149.9	1114.6	1095.6	1098.6	1189.6	1253.6	4406.6	1255.6	1330.6	1784.5
15. Uniform Average Annual System Sales	1784.5	1784.5	1784.5	1784.5	1784.5	1784.5	1784.5	1784.5	1784.5	1784.5	1784.5	1784.5	1784.5	1784.5	
16. PNW THERMAL DISPLACM MKT W/SHIFT=	3832.1	3832.1	3760.1	3983.1	3901.1	3900.1	4052.1	4089.1	3488.1	3545.1	1619.1	1179.1	2966.1	3851.1	3482.0
RETURN 1930															
17a. Deficit	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	
18a. Return	0.0	0.0	0.0	0.0	0.0	0.0	−236.7	−236.7	−236.7	−236.7	−236.7	0.0	−236.7	−236.7	
19a. Total System Sales W/Return	1046.7	1046.7	1017.7	1010.7	934.7	978.7	739.0	720.0	723.0	814.0	878.0	4267.7	880.0	955.0	1183.2
20a. Uniform Average Annual System Sales	1183.2	1183.2	1183.2	1183.2	1183.2	1183.2	1183.2	1183.2	1183.2	1183.2	1183.2	1183.2	1183.2	1183.2	
21a. PNW THERM DISPL MKT W/RETURN, 1930	4433.4	4433.4	4361.4	4584.4	4502.4	4501.4	4653.4	4690.4	4089.4	4146.4	2220.4	1780.4	3567.4	4452.4	4063.3
RETURN 1931															
17b. Deficit	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	
18b. Return	−236.7	−236.7	−236.7	−236.7	−236.7	−236.7	−236.7	−236.7	−236.7	−236.7	−236.7	0.0	−236.7	−236.7	
19b. Total System Sales W/Return	810.0	810.0	781.0	774.0	698.0	742.0	739.0	720.0	723.0	814.0	878.0	4267.7	880.0	955.0	1064.0
20b. Uniform Average Annual System Sales	1064.0	1064.0	1064.0	1064.0	1064.0	1064.0	1064.0	1064.0	1064.0	1064.0	1064.0	1064.0	1064.0	1064.0	
21b. PNW THERM DISPL MKT W/RETURN, 1931	4532.6	4532.6	4460.6	4683.6	4601.6	4600.6	4752.6	4789.6	4188.6	4245.6	2319.6	1879.6	3666.6	4551.6	4162.6
RETURN 1932															
17c. Deficit	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	−138.9	0.0	0.0	0.0	0.0	0.0	0.0	
18c. Return	−236.7	−236.7	−236.7	−236.7	−236.7	−236.7	−236.7	−236.7	0.0	0.0	0.0	0.0	0.0	0.0	
19c. Total System Sales W/Return	810.0	810.0	781.0	774.0	698.0	742.0	739.0	720.0	1098.6	1189.6	1253.6	4406.6	1255.6	1330.6	1221.3
20c. Uniform Average Annual System Sales	1221.3	1221.3	1221.3	1221.3	1221.3	1221.3	1221.3	1221.3	1221.3	1221.3	1221.3	1221.3	1221.3	1221.3	
21c. PNW THERM DISPL MKT W/RETURN, 1932	4395.3	4395.3	4323.3	4546.3	4464.3	4463.3	4615.3	4652.3	4051.3	4108.3	2182.3	1742.3	3529.3	4414.3	4025.2

NOTES:

Line 1 = Total Thermal Resources from the Step I study includes those located in the PNW and those not located in the PNW which meet Step I system load.
Line 1a = Additional backup thermal required to meet PNW deficit and return of shifted energy in years system fails to refill (138.9 + 236.7).
Line 2 = Minimum generation requirement for above resources.
Line 3 = Displaceable Thermal Resources from the Step I study, line 1 plus 1a minus line 2.
Line 4 = There is only one displaceable thermal import that is not an exchange: SCE to BPA, Optional Energy.
Line 5 = Line 3 plus line 4.
Line 6 = Total Exports Including Exchanges consists of all firm contract sales of energy exported to meet non-PNWA load.
Line 7 = These exports are part of contracts that include corresponding seasonal exchange imports.
Line 8 = Sum of the Step I study firm contract sales of energy exported to meet non-PNWA loads minus the exchanges, line 6 minus line 7.
Line 9 = This is an additional export, the portion of the seasonal exchange contracts not balanced by a corresponding import.
Line 10 = Line 8 plus line 9.
Line 11 = Firm surplus energy sales in the Step I study assumed to be exported to PSW.
Line 11a = Added thermal from line 1a, treated as an export in years system does not refill.
Line 12 = Total of lines 10 plus 11 plus 11a.
Line 13a = Amount of PNW deficit met with hydro resources.
Line 13b = Amount of shifted FELCC used to meet added exports (1032 mw) and PNW deficit (138.9 mw). The 1032 amount is a backup combustion turbine.
Line 14 = Total of lines 12 plus 13a plus 13b.
Line 15 = Uniform Average Annual System Sales, calculated from line 14.
Line 16 = PNW Thermal Displacement Market is the Total Displaceable Thermal Resources minus Uniform Average Annual System Sales adjusted by the shift, line 5 minus line 15.
Line 17 = Amount of PNW deficit to be met by backup thermal resources.
Line 18 = Amount of return of shifted FELCC in 1930, 1931, and 1932 which is met by a backup combustion turbine.
Line 19 = Total System sales w/Return, line 12 plus 17 plus 18.
Line 20 = Uniform Average Annual System Sales calculated from line 19.
Line 21 = PNW Thermal Displacement Market, line 5 minus line 20.

TABLE 4

DETERMINATION OF LOADS FOR
1995–96 STEP I, II, and III STUDIES
FOR ASSURED OPERATING PLAN

	Pacific Northwest Area Loads				STEP I STUDY							STEP II STUDY						STEP III STUDY		
Period	Energy Load w/o FirmSurp. MW 1/	Annual Energy Load Shape Percent	Base Peak Load MW	Load Factor Percent	FIRM SURPLUS MW	Peak Bias MW	1st Year Energy Shift/ Shape MW 2/	Total 1st Yr Load MW 3/	Return Energy MW 4/	Total 3rd Yr Load MW 3/	PNW Thermal Resources MW 5/	Total Load MW 6/	Hydro Load MW 7/	Shift/ Shape MW 8/	1st Yr. Hydro Load MW	Return Energy MW 9/	Energy Load Less Return MW	Total Load MW 6/	Hydro Load MW 7/	Period
Aug. 1–15	17389	92.01	21746	79.96	0	0	0.0	17389.0	−236.7	17152.3	6907	13986.3	7079.3	0.0	7079.3	−236.7	6842.6	11780.4	4873.4	Aug. 1–15
Aug. 16–31	17311	91.60	21706	79.75	0	0	0.0	17311.0	−236.7	17074.3	6907	13923.6	7016.6	0.0	7016.6	−236.7	6779.9	11727.5	4820.5	Aug. 16–31
Sept. 1–15	17064	90.29	22211	76.83	0	0	1171.2	18235.2	−236.7	16827.3	6684	13724.9	7040.9	172.8	7233.8	−236.7	6804.2	11560.2	4876.2	Sept. 1–15
Sept. 16–30	17024	90.08	22211	76.65	0	0	1171.2	18195.2	−236.7	16787.3	6684	13692.8	7008.8	172.4	7201.7	−236.7	6772.1	11533.1	4849.1	Sept. 16–30
October	17722	93.78	24305	72.92	0	0	1171.2	18893.2	−236.7	17465.3	7095	14254.2	7159.2	179.5	7352.1	−236.7	6922.5	12006.0	4911.0	October
November	19762	104.57	26780	73.79	0	0	1171.2	20933.2	−236.7	19525.3	7141	15895.0	8754.0	200.1	8946.9	−236.7	8517.3	13388.0	6247.0	November
December	21274	112.57	28954	73.46	0	0	1171.2	22445.2	−236.7	21037.3	7140	17111.1	9971.1	215.5	10184.0	−236.7	9734.4	14412.3	7272.3	December
January	21791	115.31	29925	72.82	0	0	138.9	21929.9	−236.7	21554.3	7149	17527.0	10378.0	220.7	10570.9	−236.7	10141.3	14762.6	7613.6	January
February	20946	110.84	28867	72.56	0	0	138.9	21084.9	−236.7	20709.3	6953	16647.3	9694.3	212.1	10087.2	−236.7	9657.6	14190.1	7237.1	February
March	19350	102.39	25982	74.47	0	0	138.9	19488.9	−236.7	19113.3	6114	15563.6	9449.6	196.0	9642.5	−236.7	9212.9	13108.9	6994.9	March
April 1–15	18435	97.55	24935	73.93	0	0	138.9	18573.9	−236.7	18198.3	6088	14827.7	8739.7	186.7	8932.6	−236.7	8503.0	12489.0	6401.0	April 1–15
April 16–30	18532	98.06	25019	74.07	0	0	138.9	18670.9	−236.7	18295.3	4343	14905.7	10562.7	187.7	10755.6	−236.7	10326.0	12554.7	8211.7	April 16–30
May	17775	94.06	23611	75.28	3000	4720	138.9	20913.9	0.0	20775.0	3764	14296.8	10532.8	180.0	10725.7	0.0	10532.8	12041.9	8277.9	May
June	17749	93.92	22467	79.00	0	0	138.9	17887.9	−236.7	17512.3	5739	14275.9	8536.9	179.8	8729.8	0.0	8536.9	12024.3	6285.3	June
July	17649	93.39	22058	80.01	0	0	138.9	17787.9	−236.7	17412.3	6949	14195.5	7246.5	178.7	7439.4	0.0	7246.5	11956.5	5007.5	July
Annual Average =	18898.2	100.00		75.43	254.8		472.1	19625.1	−216.6	18936.4	6402.0	15200.2	8796.2	177.1	8974.7	−177.0	8621.2	12802.8	6400.8	Annual Avg.
Crit. Per. Avg. =	19020.8			75.18	218.5						6491.4	15409.4						13731.6		
Step II Crit. Per. Avg. =	19158.2										6516.5		8892.9							
Step III Crit. Per. Avg. =	20269.2										6618.1								7113.5	Crit. Per. Avg.
					Shift/Shape 42 Month Crit. Per. Avg.					19239.3				Computed Critical Period Avg=			8892.9			
														Input Critical Per. Avg.10/=			8892.9	Input10/=	7113.5	
August 1–31	17350.0	91.81	21726.0	79.86	0	0	0.0	17350.0	−236.7	17113.3	6907.0	13955.0	7048.0	0.0	7048.0	−236.7	6811.3	11754.0	4847.0	Aug. 1–31
September 1–30	17044.0	90.19	22211.0	76.74	0	0	1171.2	18215.2	−236.7	16807.3	6684.0	13708.6	7024.8	172.6	7217.7	−236.7	6786.1	11546.6	4862.6	Sept. 1–30
April 1–30	18483.5	97.81	24977.0	74.00	0	0	138.9	18622.4	−236.7	18246.8	5215.5	14866.7	9651.2	187.2	9844.1	−236.7	9414.5	12521.9	7306.4	Apr. 1–30

Notes: 1. The PNW Area load does not include the exports, but does include pumping. The computation of the load shape for Step II/II' studies used these loads.
2. This Step I study includes a shift of 138.9 MW to meet PNW firm deficit.
3. The Step I study loads include exports which are shown on Table 4, Line 6.
4. During the critical period Step I shifted energy is returned from Jan. 1930 through Feb. 1932, except May. "Next year energy will be returned uniformly, in accordance with 1988 Entity Agreements."
5. The thermal installations include large thermal, combustion turbines and small existing thermal.
6. The total firm load for the Step II/III studies is computed to have the same shape as the load of the Pacific Northwest Area.
7. The hydro load is equal to the total load minus the Step I study thermal installations.
8. The amount of shift is shaped according to the PNW Annual Energy Load Shape by multiplying the approximate 10–month average of the Step II Shift (191.4) by the monthly load shape factors.
9. During the critical period Step II shifted energy is returned from Aug. 1944 through Apr. 30, 1945.
10. Input is the critical period average generation for the Step II/III hydro studies used to calculate the residual hydro loads.

TABLE 5

COMPARISON OF
RECENT ASSURED OPERATING PLAN STUDIES

	1990-91	1991-92	1992-93	1993-94	1994-95	1995-96
MICA TARGET OPERATION (ksfd or cfs)						
- AUG 1	3456.2	FULL	3456.2	3456.2	3456.2	3456.2
- AUG 2	FULL	FULL	FULL	FULL	FULL	FULL
- SEP	FULL	FULL	FULL	FULL	FULL	FULL
- OCT	10000	FULL	FULL	10000	3428.4	3428.4
- NOV	3122.2	3122.2	3246.2	19000	22000	22000
- DEC	23000	23000	22000	22000	24000	24000
- JAN	27000	23000	27000	26000	27000	27000
- FEB	24000	23000	25000	25000	25000	25000
- MAR	20000	18000	23000	22000	25000	25000
- APR 1	15000	18000	27000	25000	24000	24000
- APR 2	10000	18000	10000	18000	14000	14000
- MAY	10000	10000	10000	10000	10000	10000
- JUN	10000	10000	10000	10000	10000	10000
- JUL	3356.2	3456.2	3256.2	3256.2	3356.2	3356.2
CANADIAN TREATY CRC1 STORAGE DRAFT (ksfd)						
NOV 1928 (-41)	606.5	533.0	690.3	761.6	1272.6	1272.7
APR 1929 (-41)	7227.1	7049.3	7368.5	7754.1	7801.6	7801.6
JUL 1929 (-41)	759.1	707.1	1036.3	1139.5	1140.5	1140.5
AUG 1929 (-41)	135.9	183.3	560.0	983.4	1060.4	1060.4
NOV 1928 (-11)	538.7	526.7	690.3	501.7	1275.3	1275.3
JUL 1929 (-11)	761.7	708.0	1036.3	1143.0	1142.8	1142.8
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)						
- U.S. Firm Energy	0	-0.2	0.0	-1.4	-4.4	-4.4
- U.S. Dependable Capacity	+2	0	-6.0	+3.0	+2.0	+2.0
- U.S. Secondary Energy	-20	+10.5	+16.8	-8.1	+2.9	+2.9
- BCH Firm Energy	+26	+12.1	+87.1	+40.1	+56.0	+56.0
- BCH Dependable Capacity	-1	-3	+1.0	-14.0	+16.0	+16.0
- BCH Secondary Energy	-12	-2.8	-63.2	-27.0	-38.3	-38.3
HYDROREG SECONDARY LOAD (MW)						
- AUG 1	8927	10796	11070	10655	11475	11475
- AUG 2	8895	10750	11070	10655	11475	11475
- SEP	8701	10528	9981	10092	11466	11466
- OCT	8936	10726	9981	10237	12021	12021
- NOV	8819	10637	9864	10083	12272	12272
- DEC	8838	10632	9857	10074	12443	12443
- JAN	8853	10677	10996	10914	12633	12633
- FEB	8909	10734	10990	10765	12641	12641
- MAR	8624	10324	10757	10405	11909	11909
- APR 1	8268	9885	10390	10235	11817	11817
- APR 2	7831	9804	10164	10933	11573	11573
- MAY	8394	10135	7156	7114	8114	8114
- JUN	8542	10266	10615	10079	11236	11236
- JUL	8926	10761	11081	10740	11590	11590

TABLE 6

COMPARISON OF RECENT DDPB STUDIES

	1990-91	1991-92	1992-93	1993-94	1994-95	1995-96
PNW AREA AVG. ANNUAL LOAD (MW)	18103	18449	18228	18370	18898	18898
- Avg. Annual/Jan. Load (%)	87.52	87.97	87.67	86.73	86.72	86.72
- Avg. C.P. Load Factor (%) 1/	68.54	69.43	68.98	72.37	75.18	75.18
- Avg. Annual Firm Exports	333	376	444	969	905	905
- Avg. Annual Firm Surp.(MW)	492	239	388	255	255	255
THERMAL RESOURCES (MW) 2/						
- January Peak Capability	9249	9249	9218	9220	9225	9225
- C.P. Energy	5831	5800	5912	6256	6491	6491
- C.P. Minimum Generation	1894	1862	1916	1881	1621	1621
- Avg. Annual System Export Sales	NA	NA	832	1146	1440	1440
- Avg. Ann. Displaceable Market 3/	3937	3938	3095	2689	3462	3462
INSTALLED HYDRO CAPACITY (MW) 4/	34633	34584	29737	29745	29680	29680
- Base System	23808	23808	23808	23806	23736	23736
STEP I/II/III C.P. (MONTHS)	42/20/7	42/20/7	42/20/7	42/20/5.5	42/20/6	42/20/6
BASE STREAMFLOWS AT THE DALLES (cfs)						
- Step I 50-yr.Avg. Streamflow	173996	175557	175456	178235	179502	179502
- Step I C.P. Average	112054	112996	112920	112843	113177	113177
- Step II C.P. Average 5/	98717	98193	99637	99548	100146	100146
- Step III C.P. Average 6/	62502	62200	60661	57498	64733	64733
CAPACITY BENEFITS (MW)						
- Step II C.P. Generation	8944.9	8903.8	8909.4	8869.5	8892.9	8892.9
- Step III C.P. Generation	6960.7	6919.6	6871.9	7036.3	7113.5	7113.5
- Step II Gain over Step III	1984.2	1984.2	2037.5	1833.2	1779.4	1779.4
- CANADIAN ENTITLEMENT	1447.5	1428.9	1476.9	1266.5	1183.4	1183.4
- Change due to Mica Reop.	0.0	0.0	0.0	-2.3	+0.7	+0.7
- Benefit in Sales Agreement	1022.0	932.0	844.0	755.0	666.0	576.0
ENERGY BENEFITS (aMW)						
- Step II Firm Hydro	8773.1	8735.3	8898.2	8970.2	8928.3	8928.3
- Step II Thermal Disp.	1701.0	1732.1	1327.0	1148.2	1422.3	1422.3
- Step II Other Usable	403.1	396.8	484.0	492.8	421.0	421.0
- Step II Total Usable	10877.2	10864.2	10709.2	10611.1	10771.6	10771.6
- Step III Firm Hydro	6452.2	6417.0	6659.0	6485.2	6401.4	6401.4
- Step III Thermal Disp.	2402.3	2408.9	1922.4	1783.1	2123.8	2123.8
- Step III Other Usable	861.6	863.7	940.5	1031.4	940.0	940.0
- Step III Total Usable	9716.1	9689.6	9521.9	9299.7	9465.2	9465.2
- CANADIAN ENTITLEMENT	580.6	587.3	593.7	655.7	653.2	653.2
- Change due to Mica Reop.	-2.7	-3.5	+1.4	+4.6	-2.0	-2.0
- Entitlement in Sales Agre.	330.0	318.0	305.0	293.0	279.0	268.0
STEP II PEAK CAPABILITY (MW)	30603	30611	30518	30579	30530	30530
STEP II PEAK LOAD (MW)	24269	24215	24645	24414	24069	24069
STEP III PEAK CAPABILITY (MW)	30613	30574	30612	30429	30299	30299
STEP III PEAK LOAD (MW)	20413	20352	20893	20593	20273	20273

FOOTNOTES FOR TABLE 6

1. The 1988-89 through 1991-92 studies included firm contract exports in the computation of the Step I average critical period load factor and the Step II/III study load shape. In accordance with the 1988 Entity Agreements, firm exports were excluded from this computation in subsequent studies.

2. Thermal resources include combustion turbines, and all existing and planned thermal.

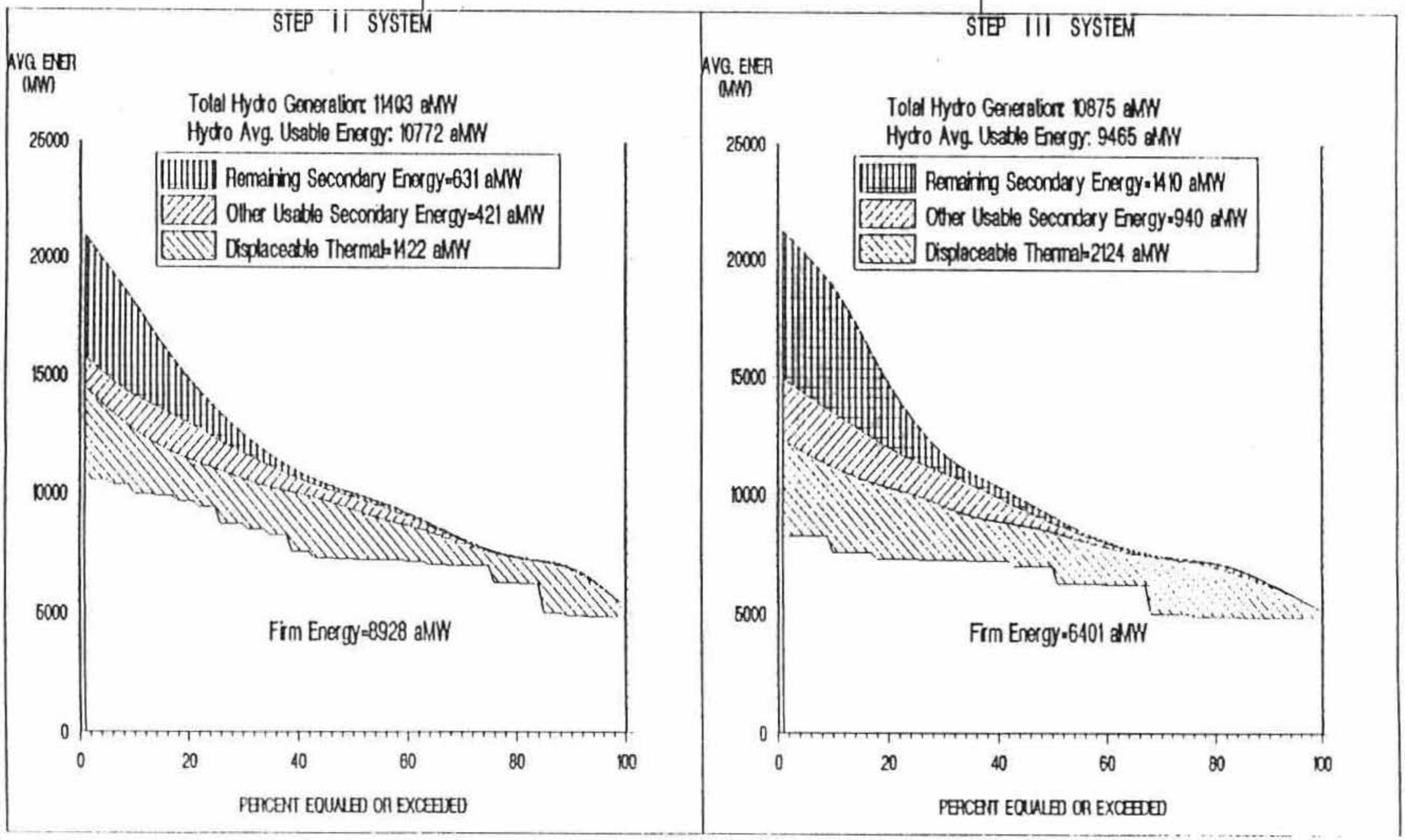
3. Displacement market for the 1993-94 Assured Operating Plan with shifted firm energy is 2689 MW; with energy returned is 3326 MW. Displacement market for the 1994-95 and 1995-96 Assured Operating Plans with shifted energy is 3462 MW. For the 1930 through 1932 return years the thermal displacement is 4063 MW, 4163 MW and 4025 MW respectively.

4. Beginning with the 1992-93 Assured Operating Plan, other coordinated hydro and independent hydro were included as adjustments to the Step I load.

5. The 1990-91 and 1991-92 Step II/III studies did not update irrigation depletions other than Grand Coulee pumping.

6. The 1993-94 Assured Operating Plan Step III has a 5 1/2 month critical period while the 1994-95 and 1995-96 Assured Operating Plans Step III have a 6 month critical period.

1995-96
DETERMINATION OF
DOWNSTREAM POWER BENEFITS
30-YEAR HYDRO
GENERATION - MW



COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

OPTIONS FOR DEVELOPMENT OF THE
DETAILED OPERATING PLAN
FOR OPERATING YEAR 1995-1996

OPTIONS FOR DEVELOPMENT OF THE DETAILED OPERATING PLAN FOR OPERATING YEAR 1995-1996

January 1991

1. Introduction

When the Assured Operating Plan for a particular year includes firm energy shifting, the Entity Agreements on Principles[1] and on Changes to Procedures[2] for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies require the Entities to conduct additional studies that exclude firm energy shifting. The purpose of these studies is to:

a) provide a non-shifted firm energy operating plan that the U.S. Entity may elect to implement in the Detailed Operating Plan, and

b) define the incremental change in downstream power benefits due to the inclusion of shifted firm energy in the Assured Operating Plan.

This report describes this non-shifted firm energy operating plan, later referred to as the Alternative Operating Plan, and documents the calculations used to define the incremental change in downstream power benefits described above. The Entities have agreed[3] that the U.S. Entity will have the option to implement this Alternative Operating Plan in the future development of a Detailed Operating Plan for 1994-95. This option is described in further detail in Section 3.

This agreement does not alter the obligation of the Canadian Entity, described in the Determination of Downstream Power Benefits for 1995-96, to deliver 2.0 MW of average annual usable energy, but no dependable capacity, to the United States Entity during the period 1 April 1995 through 31 March 1996.

2. Alternative Operating Plan

The criteria and content of the Alternative Operating Plan is essentially the same as for the Assured Operating Plan, however the details of the system operation are somewhat different. Therefore, the descriptions of the various rule curves are not repeated, but may be reviewed by referring to the Assured Operating Plan document.[4] However, the Table 1 describing the new study comparisons, Table 2 providing new Mica operating rules, and Tables 3-11 providing revised rule curves and power discharge requirements are included.

A 30-year System Regulation Study[6] was utilized to develop and test the operating rules and rule curves. It contains the agreed-upon operating constraints such as maximum and minimum project elevations, discharges, draft rates, etc. These constraints are included as part of this operating plan.

The following rules, used in the 30-year System Regulation Study[6], will apply to the operation of Canadian storage if the Alternative Operating Plan is adopted in the Detailed Operating Plan for the 1995-96 Operating Year.

(a) Mica Operating Rules

Mica project operation will be determined by the end of previous period Arrow storage content as shown in Table 2. Mica monthly outflows will be increased above the values shown in the table in the months from October to June if required to avoid violation of the Upper Rule Curve.

Under this Alternative Operating Plan, Mica storage releases in excess of 7 million acre-feet that are required to maintain the Mica outflows specified under this plan will be retained in the Arrow reservoir, subject to flood control and other project operating criteria at Arrow. The total combined storage draft from Mica and Arrow will not exceed 14.1 million acre-feet unless flood control criteria will not permit the additional Mica storage releases to be retained at Arrow. Should storage releases in excess of 14.1 million acre-feet be made, the target Mica operation will remain as specified in Table 2.

(b) Rule Curves

The operation of Canadian storage during the 1995-96 Operating Year shall be guided by a Composite Operating Rule Curve for the whole of Canadian storage, Flood Control Storage Reservation Curves for the individual projects, and operating rules for specific projects. The Operating Rule Curve is derived from the various curves as described in the Assured Operating Plan.[4]

Table 3 documents the Critical Rule Curves for Mica, Arrow and Duncan and the Composite Critical Rule Curve for the whole of Canadian storage.

Table 4 documents the Assured Refill Curves for Mica, Arrow and Duncan.

Tables 5-7 document the Variable Refill Curves, Power Discharge Requirements and Limiting Rule Curves for Duncan, Arrow and Mica respectively.

Tables 8-10 document the Upper Rule Curves for Duncan, Arrow and Mica respectively.

Table 11 illustrates the range of Composite Operating Rule curves for the whole of Canadian storage for all 30 years of the historical record. It was developed by combining the individual project operating rule curves using the same criteria as outlined in the Assured Operating Plan.

Revelstoke has been included in the 1995-96 Alternative Operating Plan and has been operated as a run-of-river project.

3. Implementation

The Entities have agreed that each year a Detailed Operating Plan will be prepared for the immediately succeeding operating year. Such plans are made under authority of Article XIV 2.(k) of the Columbia River Treaty which states:

"...the powers and the duties of the entities include:

(k) preparation and implementation of detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under the plans referred to in Annexes A and B."

The Detailed Operating Plan for 1995-96 will reflect the latest available load, resource and other pertinent data to the extent the Entities agree these data should be included in the plan.

The Entities have agreed[3] that an option to implement the Alternative Operating Plan would be advantageous to both countries. Accordingly, failing agreement on future updates, the Detailed Operating Plan for 1995-96 will include, at the discretion of the United States Entity, either:

i) the rule curves, Mica operating criteria, and other data and criteria given in the Assured Operating Plan,[4] or

ii) the rule curves, Mica operating criteria, and other data and criteria given in the Alternative Operating Plan, described in Section 2 of this document, or

iii) information as in (ii) above, with mutually acceptable criteria that will allow a provisional draft of a portion of Canadian Treaty Storage. These criteria will be designed to limit the total draft and ensure restoration of Canadian Treaty Storage similar to that which would have occurred under the Assured Operating Plan.

The Entities may also include any other changes considered advantageous to both countries. Actual operation during the 1995-96 Operating Year shall be guided by the Detailed Operating Plan.

4. Development of the Alternative Operating Plan

The Alternative Operating Plan was prepared in accordance with the same principles and procedures as were used in the development of the Assured Operating Plan[4] except for the exclusion of firm energy shifting. The tests used to evaluate Mica Operating Criteria in the Alternative Operating Plan were also the same as those utilized in the Assured Operating Plan.

(a) Determination of Optimum Generation in Canada and the United States

To determine whether optimum generation in both Canada and the United States was achieved in the system regulation studies, the firm energy capability, dependable peaking capability and average annual usable secondary energy were computed for both the Canadian and United States systems.

In the studies for the 1995-96 Alternative Operating Plan, the Canadian storage operation was operated to achieve a weighted sum of the three quantities that was greater than the weighted sum achieved under an operation of Canadian storage for optimum generation in the United States alone. The same weights were used in both the Alternative Operating Plan and the Assured Operating Plan studies.

Table 1 shows the results from the studies adopted for the 1995-96 Alternative Operating Plan and from studies designed to achieve optimum generation in the United States.

(b) Maximum Permitted Reduction in Downstream Power Benefits

Although there is no specific requirement that operating plans prepared under the authority of Article XIV 2.(k) of the Treaty pass tests related to the maximum permitted reduction in downstream power benefits, these tests were applied to the Mica operating criteria developed for the Alternative Operating Plan.

Separate system regulation studies, that exclude energy shifting, were developed reflecting (i) Canadian storage operation for optimum generation in both Canada and the United States, using the Mica Project operating criteria described in Section 2(a), and (ii) Canadian storage operation for optimum generation in the United States alone. For these Mica operating criteria, there is a 0.3 MW increase in the entitlement to average annual usable energy and 0.5 MW loss in Entitlement to dependable capacity compared to an operation for optimum generation in the United States alone.

5. Canadian Entitlement Computations

The downstream power benefits for the Alternative Operating Plan were computed in accordance with the same procedures described in the Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 1995-96 document[4], except for specific changes described below.

(a) Results of Canadian Entitlement Computations

For the Alternative Operating Plan, one-half of the downstream power benefits in the United States of America attributable to operation for optimum power generation in Canada and the United States of America was computed to be (see Table 12):

Dependable Capacity	=	1,184.3 MW
Average Annual Energy	=	634.6 MW

(b) Computation of Maximum Allowable Reduction in Entitlement

The minimum permitted downstream power benefit was computed in accordance with Treaty Annex A, Paragraph 7 and Part III, Paragraph 15c(2) of the Principles and Procedures[7]. The resulting minimum permitted entitlement to downstream power benefits for the 1995-96 Alternative Operating Plan was based on the formula:

$$X - (Y - Z)$$

where:

X is one-half the downstream power benefits derived from the previous year's Assured Operating Plan 95-42 and 95-13 studies,

Y is one-half the downstream power benefits derived from the previous year's Assured Operating Plan 95-12 and 95-13 studies, and

Z is one-half the downstream power benefits derived from the present year's Alternative Operating Plan 96-22 and 96-13 studies.

The quantities X and Y were computed in the Determination of Downstream Power Benefits for the Assured Operating Plan for the 1994-95 Operating Year. The quantity Z, which is computed from one-half of the downstream power benefits determined for 15 MAF of Canadian Treaty storage operated for optimum power generation in the United States of America, is computed in Table 12.

Application of the formula X - (Y - Z) yields the following:

Dependable Capacity	=	1,184.3	-	(1,184.8	-	1,162.8)	=	1,162.3 MW
Average Annual Energy	=	634.6	-	(634.3	-	629.3)	=	629.6 MW

The computed entitlement in Section 5(a) above exceeds these amounts.

(c) Effect on Sale of Canadian Entitlement

For the Alternative Operating Plan, one-half of the downstream power benefits in the United States of America attributable to operation in accordance with Treaty Annex A, Paragraph 8, for optimum power generation in the United States of America alone was computed to be (see Table 12):

Dependable Capacity	=	1,184.8 MW
Average Annual Energy	=	634.3 MW

A comparison with the entitlement to downstream power benefits computed in the Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 1995-96[5], for optimum power generation in the United State of America alone, indicates that inclusion of firm energy shifting results in an increase of 20.9 MW of average annual energy and a decrease of 2.1 MW of dependable capacity. This represents the change in the purchased portion of the Canadian Entitlement resulting from including firm energy shifting in the Assured Operating Plan.

A comparison with the entitlement to downstream power benefits computed in Section 5(a) indicates that operation for optimum in both countries results in an increase of 0.3 MW of average annual usable energy, and a decrease of 0.5 MW in dependable capacity.

Since the Alternative Operating Plan has not being adopted for the Assured Operating Plan, the quantities arising from the entitlement computations are not involved in the power transfers described in Sections 7 and 10 of the Canadian Entitlement Purchase Agreement[8].

(d) Summary of Entitlement Computations

The following Tables and Chart summarize the study results:

Table 12 Computation of Canadian Entitlement for 1995-96 Alternative Operating Plan:

A. Optimum Generation in Canada and the U.S.
B. Optimum Generation in the U.S. Only
C. Optimum Generation in the U.S. and a 0.5 Million Acre-Feet Reduction in Total Canadian Treaty Storage

The essential elements used in the computation of the Canadian Entitlement to downstream power benefits, the minimum permitted downstream power benefits, and the reduction in downstream power benefits attributable to the operation of Canadian Treaty storage for optimum power generation in the United States of America only, are shown on this table.

Table 13 Summary of Power Regulations from 1995-96 Alternative Operating Plan for the Computation of Canadian Entitlement to Downstream Power Benefits

This table summarizes the results of the Step I, II, and III power regulation studies for each project and the total system.

Table 14 Determination of Displaceable Thermal Market for 1995-96 Alternative Operating Plan

This table shows the computation of the potential thermal displacement market for the downstream power benefit determination of usable energy. The potential thermal displacement market was limited to the existing and scheduled thermal energy capability after allowance for reserves, minimum thermal generation, and reductions for the thermal resources used outside the PNW area.

Table 15 Determination of Loads for 1995-96 Step I, II, and III Studies for Alternative Operating Plan

This table shows the computation of the Step I, II, and III loads. The monthly loads for Step II and III studies have the same ratio between each month and the annual average as does the Pacific Northwest (PNW) area load. The PNW area firm loads on this table were based on the current forecast data. The Grand Coulee pumping load is also included in this estimate. The method for computing the firm load for the Step II and III studies is described in POP and clarified in the 1988 Entity Agreements.

Chart 1. 1995-96 Determination of Downstream Power Benefits 30-Year Hydro Generation

This chart shows duration curves of the hydro generation from the Step II and III studies and graphically illustrates the change in the portion of secondary energy that is usable for thermal displacement due to operation of Treaty storage. Secondary energy is the energy capability each month which exceeds the firm hydro loads shown in Table 15. The usable secondary energy in average megawatts for the Step II and III studies is computed in accordance with Annex B, Paragraphs 3(b) and 3(c), as the portion of secondary energy which can displace thermal resources used to meet PNW area loads plus the other usable secondary generation. The Entities have agreed that "the other usable secondary" is computed on the basis of 40 percent of the remainder after thermal displacement.

6. Summary of Differences from the 1995-96 Assured Operating Plan

Table 16 and Table 17 document various data from this Alternative Operating Plan and Determination of Downstream Power Benefits and compare it to the Assured Operating Plan for 1995-96 and to previous Alternative Operating Plans and their associated Downstream Power Benefit Determinations.

In this Alternative Operating Plan, there was no shifting of firm energy load carrying capability. However, all of the year-to-year changes in project data, streamflows, system loads, energy exchanges and operating procedures, apart from those related to energy shifting, described in the Determination of Downstream Power Benefits for the 1995-96 Assured Operating Plan also apply to these studies. An explanation of the more important changes compared to the 1995-96 Assured Operation Plan is given below:

(a) Loads and Resources

Conservation resources of 115 Avg. MW were added to eliminate deficits in the region.

(b) Downstream Benefit Computation

The potential displaceable thermal market was decreased by a uniform amount equal to the amount of thermal power being used to meet loads outside the Pacific Northwest Area. The components of the exports out of the region are shown in Table 14. Only the amount of the seasonal exchange exports, not balanced by corresponding imports, was included in the net export amount. The potential displaceable thermal market was increased by the Southern California Edison to Bonneville Power Administration displaceable thermal energy import, which returns January through April 15.

REFERENCES

1 Columbia River Treaty Entity Agreement on Principles for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, dated 28 July 1988.

2 Columbia River Treaty Entity Agreement on Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, dated 12 August 1988.

3 Columbia River Treaty Entity Agreement on the Assured Operating Plan, Determination of Downstream Power Benefits and Options for Development of the Detailed Operating Plan for Operating Year 1995-96.

4 Columbia River Treaty Assured Operating Plan for Operating Year 1995-96, dated January 1991.

5 Columbia River Treaty Determination of Downstream Power Benefits for the Assured Operating Plan for Operating Year 1995-96, dated January 1991.

6 Bonneville Power Administration Hydroelectric Power Planning Program, Alternative Operating Plan 30-year System Regulation Study 96-41 (no shift), dated 25 April 1990.

7 Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans dated May 1983.

8 Canadian Entitlement Purchase Agreement, dated 13 August 1964.

TABLE 1

COMPARISON OF ALTERNATIVE OPERATING PLAN STUDY RESULTS

Study 96-41 (no shift) provides Optimum Generation in Canada and in the United States.
Study 96-11 (no shift) provides Optimum Generation in the United States only.

	Study No. 96-41 No Shift	Study No. 96-11 No Shift	Net Gain	Weight	Value
1. Firm Energy Capability (Avg. MW)					
U.S. System[1]	12,182.1	12,188.6	-6.5		
Canada[2]	1,641.9	1,586.8	+55.1		
Total	13,824.0	13,775.4	+48.6	3	+145.8
2. Dependable Peaking Capacity (MW)					
U.S. System[3]	31,803.0	31,803.0	0.0		
Canada[4]	3,510.0	3,518.0	-8.0		
Total	35,313.0	35,321.0	-8.0	1	-8.0
3. Average Annual Usable Secondary Energy (Avg. MW)					
U.S. System[5]	3,002.6	2,989.1	+13.5		
Canada[6]	130.7	165.2	-34.5		
Total	3,133.3	3,154.3	-21.0	2	-42.0
			Net Change in Value =		+95.8

Notes:

(1) U.S. System firm energy capability was determined over the U.S. system critical period beginning 1 September 1928 and ending 29 February 1932.

(2) Canadian system (Mica + Revelstoke) firm energy capability was determined over the Canadian system critical period beginning 1 October 1940 and ending 30 April 1946.

(3) U.S. system dependable peaking capability was determined from January 1937.

(4) Canadian system (Mica + Revelstoke) dependable peaking capability was determined from December 1944.

(5) U.S. system 30-year average secondary energy limited to secondary market.

(6) Canadian system (Mica and Revelstoke) 30-year average generation minus firm energy capability.

TABLE 2

MICA PROJECT OPERATING CRITERIA
ALTERNATIVE OPERATING PLAN

	End of Previous Period Arrow Storage Content	-------- Target Operation ---------		Minimum Outflow	Minimum Treaty Content[2]
		Period Average Outflow	End-of-Period Treaty Content[1]		
Month	(ksfd)	(cfs)	(ksfd)	(cfs)	(ksfd)
August 1-15	3 300 - FULL	-	3 456.2	10 000	0.0
	0 - 3 300	27 000			
August 16-31	2 400 - FULL	-	3 529.2	10 000	0.0
	0 - 2 400	27 000			
September	2 500 - FULL	-	3 529.2	10 000	0.0
	0 - 2 500	27 000			
October	2 900 - FULL	11 000	-	10 000	0.0
	200 - 2 900	27 000			
	0 - 200	31 000			
November	3 400 - FULL	-	3 185.5	10 000	0.0
	3 000 - 3 400	23 000			
	0 - 3 000	27 000			
December	3 200 - FULL	21 000	-	15 000	756.2
	2 200 - 3 200	27 000			
	0 - 2 200	34 000			
January	2 100 - FULL	27 000	-	15 000	356.2
	0 - 2 100	34 000			
February	0 - FULL	23 000	-	15 000	0.0
March	0 - FULL	22 000	-	15 000	0.0
April 1-15	0 - FULL	-	156.2	15 000	0.0
April 16-30	0 - FULL	-	0.0	10 000	0.0
May	0 - FULL	10 000	-	10 000	0.0
June	0 - FULL	10 000	-	10 000	0.0
July	2 300 - FULL	-	3 356.2	10 000	0.0
	0 - 2 300	27 000			

Notes:

(1) A maximum outflow of 34000 cfs will apply if the target end-of-period storage content is less than 3529.2 ksfd except in April where a maximum outflow of 27 000 cfs will apply from April 1-15 and a maximum outflow of 25 000 cfs will apply from April 16-30.

(2) Mica outflows will be reduced to minimum to maintain the reservoir above the minimum Treaty storage content. This will override any target flow.

COLUMBIA RIVER TREATY
CRITICAL RULE CURVES
END OF MONTH CONTENTS IN KSFD
1995-96 OPERATING YEAR

TABLE 3

MICA

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	3529.2	3529.2	3466.9	3407.2	3303.2	3049.0	2151.9	1162.3	781.1	324.1	34.8	494.6	2127.8	2898.7
2ND YR	3292.9	3338.9	3164.6	2916.1	2446.0	1928.4	874.3	384.8	140.8	27.2	51.4	32.4	1236.9	2618.2
3RD YR	2955.9	3134.5	3099.3	2856.8	2394.6	1885.2	864.0	147.1	68.6	93.3	26.0	12.8	847.4	1579.5
4TH YR	1636.1	1630.8	1351.4	951.1	387.3	4.6	10.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0

ARROW

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	3579.6	3579.6	3532.6	3441.8	3301.3	2696.7	1683.1	901.1	1077.8	515.5	269.4	1109.5	2656.5	3428.8
2ND YR	3432.7	3399.9	3342.1	3050.2	2506.7	1766.3	789.3	186.4	197.4	91.5	349.4	658.3	1995.2	3041.9
3RD YR	3282.9	3232.0	3256.0	2982.3	2436.8	1648.0	898.9	96.5	158.1	128.4	95.0	665.1	1226.2	1840.7
4TH YR	1876.7	1632.0	1598.3	1364.2	1247.1	822.2	346.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

DUNCAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	705.8	705.8	692.6	641.7	502.5	407.8	254.3	235.1	129.3	53.8	58.9	167.3	442.1	610.3
2ND YR	552.3	493.1	383.2	182.1	19.9	18.6	9.8	14.1	4.8	16.3	0.8	0.0	219.6	166.6
3RD YR	114.7	160.8	167.2	11.0	10.6	8.9	10.5	9.8	7.2	12.5	4.0	62.3	208.1	134.0
4TH YR	50.3	6.0	2.3	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

COMPOSITE

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	7814.6	7814.6	7692.1	7490.7	7107.0	6153.5	4089.3	2298.5	1988.2	893.4	363.1	1771.4	5226.4	6937.8
2ND YR	7277.9	7231.9	6889.9	6148.4	4972.6	3713.3	1673.4	585.3	343.0	135.0	401.6	690.7	3451.7	5826.7
3RD YR	6353.5	6527.3	6522.5	5850.1	4842.0	3542.1	1773.4	253.4	233.9	234.2	125.0	740.2	2281.7	3554.2
4TH YR	3563.1	3268.8	2952.0	2317.1	1634.4	826.8	356.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0

COLUMBIA RIVER TREATY
ASSURED REFILL CURVES
END OF MONTH CONTENTS IN KSFD
1995-96 OPERATING YEAR

TABLE 4

MICA

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1757.2	2340.2	2943.2	3121.6	3186.9	3203.4	3198.3	2710.9	2097.7	1822.9	1586.4	1681.5	2647.2	3529.2

ARROW

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
0.0	0.0	0.0	34.9	274.3	427.1	478.0	709.7	1003.4	1108.8	1202.9	1977.3	3105.6	3579.6

DUNCAN

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
63.3	134.2	200.5	231.2	248.7	259.9	270.1	268.1	269.8	277.0	261.7	360.0	540.9	705.8

DUNCAN VARIABLE REFILL CURVE (KSFD)
1995-96 OPERATING YEAR

TABLE 5

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							481.6	442.8	433.1	445.8	466.8	446.2	594.0	705.8
1929-30							479.6	440.8	430.8	443.3	477.2	467.1	605.4	,,
1930-31							424.2	386.6	380.1	399.3	428.6	415.5	594.0	,,
1931-32							1.2	1.6	0.8	0.0	35.6	112.3	447.9	,,
1932-33							,,	,,	,,	,,	0.0	0.0	314.3	,,
1933-34							,,	,,	,,	,,	45.9	144.5	488.3	,,
1934-35							34.2	10.2	24.5	55.3	119.7	177.5	453.4	,,
1935-36							38.8	13.1	14.4	43.9	108.3	182.1	504.4	,,
1936-37							427.7	390.1	382.2	396.6	421.0	407.6	576.2	,,
1937-38							1.2	1.6	0.8	16.2	91.5	168.0	471.8	,,
1938-39							279.1	244.5	240.0	263.4	309.1	326.7	577.0	,,
1939-40							267.8	233.0	235.8	268.8	315.5	328.8	565.7	,,
1940-41							347.4	311.4	310.4	341.9	391.6	406.7	589.1	,,
1941-42							152.2	125.6	134.9	162.8	221.8	276.9	520.6	,,
1942-43							121.4	96.5	105.7	131.9	199.9	280.8	505.0	,,
1943-44							504.0	464.3	459.4	473.1	494.2	479.6	624.0	,,
1944-45							424.9	387.3	383.3	400.0	423.7	408.0	582.4	,,
1945-46							1.2	1.6	0.8	0.0	0.0	56.8	440.9	,,
1946-47							,,	,,	,,	,,	9.3	100.4	453.6	,,
1947-48							,,	,,	,,	,,	43.8	118.7	464.5	,,
1948-49							173.8	147.8	153.6	175.7	233.2	294.2	565.4	,,
1949-50							1.2	1.6	0.8	0.0	61.4	126.9	408.6	,,
1950-51							,,	,,	,,	,,	11.1	92.4	439.6	,,
1951-52							5.5	,,	,,	24.4	95.7	178.3	484.5	,,
1952-53							4.9	,,	,,	23.7	93.2	156.5	450.9	,,
1953-54							1.2	,,	,,	0.0	0.0	18.9	381.9	,,
1954-55							,,	,,	,,	,,	41.5	106.2	386.2	,,
1955-56							,,	,,	,,	,,	0.0	66.8	437.5	,,
1956-57							,,	,,	,,	,,	48.2	119.6	501.4	,,
1957-58							,,	,,	,,	,,	0.0	57.2	453.6	,,
ECC LOWER LIMIT							1.2	1.6	0.8					
POWER DISCHARGE REQUIREMENTS IN CFS						80 MAF--	100	500	500	500	2000	2000	2000	2000
FOR JANUARY THROUGH JULY						90 MAF--	100	100	100	100	100	100	100	100
VOLUME RUNOFF AT THE DALLES						95 MAF--	100	100	100	100	100	100	100	100

ARROW VARIABLE REFILL CURVE (KSFD)
1995-96 OPERATING YEAR

TABLE 6

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							2818.9	2900.9	2999.4	3313.2	3579.6	3311.4	3579.6	3579.6
1929-30							1202.8	1329.9	1521.2	1943.0	2807.6	2750.4	3421.9	,,
1930-31							1608.6	1724.4	1854.5	2249.3	2961.0	2569.7	3421.1	,,
1931-32							627.2	246.2	183.3	0.0	125.4	1107.0	2640.9	,,
1932-33							,,	,,	,,	,,	453.5	1291.2	2610.6	,,
1933-34							,,	,,	,,	,,	505.0	1713.6	3119.7	,,
1934-35							,,	,,	,,	,,	439.7	1078.0	2554.7	,,
1935-36							,,	,,	,,	,,	490.7	1262.4	2870.9	,,
1936-37							3109.4	3183.2	3279.7	3540.8	3579.6	3499.4	3579.6	,,
1937-38							627.2	246.2	183.3	228.0	989.9	1752.3	2973.1	,,
1938-39							1421.0	1542.0	1681.7	2084.1	2883.2	2669.4	3579.6	,,
1939-40							951.3	1070.9	1284.1	1809.2	2690.3	2466.0	3497.0	,,
1940-41							2316.6	2412.6	2576.8	3041.8	3579.6	3573.4	3579.6	,,
1941-42							627.2	644.6	673.2	709.7	1307.1	1782.9	2922.7	,,
1942-43							1088.0	1095.8	1058.5	1392.8	2377.9	2991.6	3412.9	,,
1943-44							3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	3579.6	,,
1944-45							3077.0	3151.7	3305.0	,,	,,	3527.3	,,	,,
1945-46							627.2	246.2	183.3	0.0	424.3	1314.8	2800.0	,,
1946-47							,,	,,	,,	,,	793.0	1660.2	2936.5	,,
1947-48							,,	,,	,,	,,	554.6	1374.6	2800.6	,,
1948-49							,,	,,	520.0	1115.0	2096.3	2702.4	3579.6	,,
1949-50							,,	,,	183.3	0.0	534.3	1291.5	2496.0	,,
1950-51							,,	,,	,,	77.3	848.8	1628.0	3065.0	,,
1951-52							,,	,,	,,	78.7	968.7	1772.0	3169.1	,,
1952-53							,,	296.7	296.2	597.4	1555.2	2049.7	3128.6	,,
1953-54							,,	246.2	183.3	0.0	206.9	1009.7	2492.1	,,
1954-55							,,	,,	,,	,,	525.4	1217.1	2414.8	,,
1955-56							,,	,,	,,	,,	363.9	1339.5	2821.6	,,
1956-57							,,	,,	,,	,,	363.4	1172.5	3254.5	,,
1957-58							,,	,,	,,	,,	393.1	1226.1	2942.3	,,

		JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
ECC LOWER LIMIT		627.2	246.2	183.3					
POWER DISCHARGE REQUIREMENTS IN CFS	80 MAF--	5000	15000	18000	22000	30000	40000	45000	45000
FOR JANUARY THROUGH JULY	90 MAF--	5000	5000	5000	5000	5000	5000	5000	5000
VOLUME RUNOFF AT THE DALLES	95 MAF--	5000	5000	5000	5000	10000	10000	35000	35000

MICA VARIABLE REFILL CURVE (KSFD)
1995-96 OPERATING YEAR

TABLE 7

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							3529.2	3529.2	3404.3	3359.3	3208.7	2621.2	3068.3	3529.2
1929-30							,,	2996.2	2328.2	2380.0	2371.3	2002.6	2784.2	,,
1930-31							,,	3265.2	2593.0	2604.9	2528.3	2023.2	2859.4	,,
1931-32							1131.3	1017.2	971.0	1210.9	1358.1	1390.7	2647.0	,,
1932-33							1066.2	956.3	927.5	1168.7	1293.4	1285.6	2483.5	,,
1933-34							317.6	157.4	122.2	436.8	666.2	1028.9	2736.0	,,
1934-35							,,	100.5	0.0	292.1	459.8	531.1	1995.7	,,
1935-36							921.5	627.0	371.4	604.7	738.5	806.1	2423.5	,,
1936-37							3529.2	3529.2	3357.3	3305.7	3200.2	2635.3	3100.7	,,
1937-38							1429.2	1311.7	1265.9	1488.1	1613.7	1617.8	2738.4	,,
1938-39							3529.2	3138.7	2480.3	2524.7	2469.8	2047.4	3092.4	,,
1939-40							3488.8	2880.5	2239.1	2295.7	2266.2	1837.7	2851.9	,,
1940-41							3529.2	3469.4	2816.9	2830.3	2822.1	2407.3	3082.3	,,
1941-42							903.8	694.8	546.2	776.9	925.8	996.4	2344.4	,,
1942-43							2057.8	1927.1	1883.8	2051.3	2207.7	2256.9	2976.7	,,
1943-44							3529.2	3529.2	3463.3	3406.8	3279.1	2743.9	3239.3	,,
1944-45							,,	,,	3436.7	3397.5	3253.2	2669.7	3158.4	,,
1945-46							804.5	700.2	652.1	904.2	1051.8	1080.9	2641.4	,,
1946-47							982.2	874.1	855.1	1112.2	1273.9	1351.4	2712.0	,,
1947-48							907.3	797.9	763.7	1003.4	1136.8	1139.5	2597.8	,,
1948-49							2618.2	2475.8	2416.3	2544.0	2613.9	2544.2	3370.3	,,
1949-50							1229.7	1116.4	1058.6	1280.8	1407.3	1366.2	2409.6	,,
1950-51							1271.0	1156.9	1131.3	1364.4	1513.5	1488.7	2771.3	,,
1951-52							1642.4	1517.5	1466.9	1653.4	1762.4	1786.3	2918.0	,,
1952-53							1946.1	1817.8	1776.9	1952.3	2029.9	1944.9	2884.4	,,
1953-54							808.2	703.8	686.5	948.5	1087.4	1053.9	2381.3	,,
1954-55							1294.9	1173.8	1149.1	1380.0	1512.7	1485.8	2445.4	,,
1955-56							1128.3	1014.2	968.3	1199.5	1332.7	1384.7	2686.3	,,
1956-57							1290.8	1176.2	1145.1	1374.5	1501.3	1472.7	3016.3	,,
1957-58							1136.1	1024.8	1000.0	1245.4	1391.6	1369.6	2779.9	,,
ECC LOWER LIMIT							317.6	0.0	0.0					

		JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS IN CFS	80 MAF--	3000	20000	23000	23000	23000	25000	28000	28000
FOR JANUARY THROUGH JULY	90 MAF--	3000	3000	3000	3000	3000	3000	3000	3000
VOLUME RUNOFF AT THE DALLES	95 MAF--	3000	3000	3000	10000	10000	10000	20000	25000

TABLE 8

DUNCAN
FLOOD CONTROL STORAGE RESERVATION CURVES
1995-96 OPERATING YEAR
KSFD

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	705.8	705.8	705.8	705.8	705.8	504.1	418.3	340.8	340.8	348.1	360.5	443.7	574.4	705.8
1929-30	,,	,,	,,	,,	,,	,,	408.4	322.1	322.1	329.8	342.9	430.3	567.7	,,
1930-31	,,	,,	,,	,,	,,	,,	391.0	288.9	288.9	297.2	311.4	406.4	555.7	,,
1931-32	,,	,,	,,	,,	,,	,,	277.3	65.5	65.5	80.9	109.1	281.3	609.8	,,
1932-33	,,	,,	,,	,,	,,	,,	273.7	,,	,,	75.1	94.3	191.7	573.3	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	65.5	127.0	339.6	605.3	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	83.5	187.2	488.1	,,
1935-36	,,	,,	,,	,,	,,	,,	277.3	,,	,,	71.3	119.3	351.7	705.8	,,
1936-37	,,	,,	,,	,,	,,	,,	377.7	263.6	263.6	272.5	287.5	388.3	546.6	,,
1937-38	,,	,,	,,	,,	,,	,,	293.0	102.3	102.3	113.2	119.2	245.3	551.9	,,
1938-39	,,	,,	,,	,,	,,	,,	288.0	92.7	92.7	109.3	132.6	399.3	705.8	,,
1939-40	,,	,,	,,	,,	,,	,,	303.2	115.4	115.4	127.2	150.9	410.6	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	345.5	202.1	202.1	212.2	229.3	344.2	524.5	,,
1941-42	,,	,,	,,	,,	,,	,,	328.5	169.9	169.9	179.0	201.5	326.4	501.6	,,
1942-43	,,	,,	,,	,,	,,	,,	333.0	178.4	178.4	192.2	221.1	289.2	653.1	,,
1943-44	,,	,,	,,	,,	,,	,,	416.4	334.7	334.7	342.1	354.7	439.4	572.2	,,
1944-45	,,	,,	,,	,,	,,	,,	384.9	277.3	277.3	278.6	279.4	382.3	580.3	,,
1945-46	,,	,,	,,	,,	,,	,,	273.7	65.5	65.5	75.7	95.6	322.3	647.5	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	77.1	102.0	314.0	629.6	,,
1947-48	,,	,,	,,	,,	,,	,,	277.3	,,	,,	65.5	65.5	300.5	705.8	,,
1948-49	,,	,,	,,	,,	,,	,,	371.1	251.0	251.0	256.9	277.0	434.3	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	273.7	65.5	65.5	65.5	65.5	184.0	525.3	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	285.1	534.2	,,
1951-52	,,	,,	,,	,,	,,	,,	277.3	,,	,,	,,	67.4	92.4	255.0	,,
1952-53	,,	,,	,,	,,	,,	,,	273.7	,,	,,	71.9	84.7	234.6	522.7	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	73.2	84.1	237.1	547.6	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	71.9	80.9	154.5	488.8	,,
1955-56	,,	,,	,,	,,	,,	,,	277.3	,,	,,	65.5	84.7	266.6	585.4	,,
1956-57	,,	,,	,,	,,	,,	,,	273.7	,,	,,	74.5	89.9	376.1	655.8	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	77.1	96.3	359.4	705.8	,,

TABLE 9

ARROW
FLOOD CONTROL STORAGE RESERVATION CURVES
1995-96 OPERATING YEAR
KSFD

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	3579.6	3579.6	3579.6	3453.6	3453.6	3075.4	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	3579.6
1929-30	,,	,,	,,	,,	,,	,,	2998.3	2928.3	2851.2	2870.1	2902.9	3082.8	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	2371.6	1712.7	1008.4	1016.1	1126.6	2224.6	,,	,,
1932-33	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1008.4	1036.6	1761.7	3034.5	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1784.9	2327.4	3579.6	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	1725.7	3034.5	,,
1935-36	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1070.1	1373.5	2134.6	3579.6	,,
1936-37	,,	,,	,,	,,	,,	,,	2940.8	2818.8	2684.1	2707.4	2755.8	3266.2	,,	,,
1937-38	,,	,,	,,	,,	,,	,,	2363.5	1720.2	1008.4	1082.9	1278.3	1831.2	3147.6	,,
1938-39	,,	,,	,,	,,	,,	,,	2584.5	2141.3	1650.3	1719.8	1843.3	2661.3	3579.6	,,
1939-40	,,	,,	,,	,,	,,	,,	2793.4	2529.4	2247.3	2287.2	2380.5	2913.4	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	,,	,,
1941-42	,,	,,	,,	,,	,,	,,	2363.5	1720.2	1008.4	1064.9	1149.8	1934.0	,,	,,
1942-43	,,	,,	,,	,,	,,	,,	,,	,,	,,	1111.2	1322.0	1440.3	2389.1	,,
1943-44	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	,,
1944-45	,,	,,	,,	,,	,,	,,	2582.9	2138.0	1645.5	1672.5	1744.1	2368.8	3347.5	,,
1945-46	,,	,,	,,	,,	,,	,,	2363.5	1720.2	1008.4	1072.6	1242.3	2201.4	3579.6	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	1075.2	1360.6	2147.4	,,	,,
1947-48	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1036.6	1183.2	2216.8	,,	,,
1948-49	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1144.6	1376.0	2494.5	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	1008.4	1113.8	2232.3	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1355.5	3337.9	,,
1951-52	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1070.1	1345.2	1792.6	3013.9	,,
1952-53	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1057.2	1172.9	1476.3	,,	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1134.3	1628.0	1898.0	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	1075.2	1090.6	1653.7	3224.8	,,
1955-56	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1008.4	1216.6	1990.6	2993.4	,,
1956-57	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1077.8	1224.3	2651.4	3579.6	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	1046.9	1190.9	2242.5	,,	,,

TABLE 10

MICA
FLOOD CONTROL STORAGE RESERVATION CURVES
1995-96 OPERATING YEAR
KSFD

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	3529.2	3529.2	3529.2	3428.4	3428.4	3428.4	3385.7	3347.2	3304.6	3304.6	3304.6	3369.1	3447.9	3529.2
1929-30	,,	,,	,,	,,	,,	,,	3352.6	3284.4	3208.7	3208.7	3208.7	3300.7	3413.2	,,
1930-31	,,	,,	,,	,,	,,	,,	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	,,
1931-32	,,	,,	,,	,,	,,	,,	3105.7	2803.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1932-33	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	,,	,,	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1935-36	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	,,	,,	,,
1936-37	,,	,,	,,	,,	,,	,,	3330.6	3242.3	3144.5	3144.5	3144.5	3323.3	3398.4	,,
1937-38	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1938-39	,,	,,	,,	,,	,,	,,	3193.8	2981.4	2746.8	2746.8	2746.8	2971.4	3246.0	,,
1939-40	,,	,,	,,	,,	,,	,,	3274.3	3130.5	2976.4	2976.4	2976.4	3135.1	3329.1	,,
1940-41	,,	,,	,,	,,	,,	,,	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	,,
1941-42	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1942-43	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1943-44	,,	,,	,,	,,	,,	,,	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	,,
1944-45	,,	,,	,,	,,	,,	,,	3193.1	2980.2	2745.0	2745.0	2745.0	2970.0	3245.3	,,
1945-46	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1947-48	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	,,	,,	,,
1948-49	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	,,	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1951-52	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	,,	,,	,,
1952-53	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	,,	,,	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1955-56	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	2695.5	3172.7	,,
1956-57	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	2781.5	3149.6	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,

COLUMBIA RIVER TREATY
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF MONTH CONTENTS IN KSFD
1995-96 OPERATING YEAR

TABLE 11

FLOW YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7692.1	7490.7	7107.0	6307.9	5151.5	3880.1	3445.3	3208.7	3051.0	4018.8	6293.7	7814.6
1929-30	,,	,,	,,	,,	,,	,,	4671.2	,,	,,	,,	,,	,,	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	5077.0	,,	,,	,,	,,	,,	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	1759.7	1265.0	1155.1	1210.9	1519.1	2610.0	5735.8	,,
1932-33	,,	,,	,,	,,	,,	,,	1694.6	1204.1	1111.6	1168.7	1746.9	2576.8	5408.4	,,
1933-34	,,	,,	,,	,,	,,	,,	946.0	405.2	306.3	436.8	1217.1	2887.0	6241.1	,,
1934-35	,,	,,	,,	,,	,,	,,	979.0	356.9	207.8	347.4	1019.2	1786.6	5003.8	,,
1935-36	,,	,,	,,	,,	,,	,,	1587.5	886.3	569.1	648.6	1337.5	2250.6	5798.8	,,
1936-37	,,	,,	,,	,,	,,	,,	5151.5	3880.1	3445.3	3208.7	3051.0	4018.8	6293.7	,,
1937-38	,,	,,	,,	,,	,,	,,	2057.6	1559.5	1450.0	1732.3	2667.8	3538.1	6092.1	,,
1938-39	,,	,,	,,	,,	,,	,,	4889.4	3856.5	3415.5	3195.1	3051.0	3985.5	6293.7	,,
1939-40	,,	,,	,,	,,	,,	,,	4417.4	3845.0	3411.3	3200.5	,,	3987.6	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	5151.5	3880.1	3445.3	3208.7	,,	4018.8	,,	,,
1941-42	,,	,,	,,	,,	,,	,,	1683.2	1465.0	1354.3	1649.4	2350.5	3056.2	5787.7	,,
1942-43	,,	,,	,,	,,	,,	,,	3267.2	2924.7	3048.0	3063.6	2989.2	3939.6	6257.8	,,
1943-44	,,	,,	,,	,,	,,	,,	5151.5	3880.1	3445.3	3208.7	3051.0	4018.8	6293.7	,,
1944-45	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1945-46	,,	,,	,,	,,	,,	,,	1432.9	948.0	836.2	904.2	1476.1	2452.5	5882.3	,,
1946-47	,,	,,	,,	,,	,,	,,	1610.6	1121.9	1039.2	1112.2	2076.2	3112.0	6037.3	,,
1947-48	,,	,,	,,	,,	,,	,,	1535.7	1045.7	947.8	1003.4	1735.2	2632.8	5862.9	,,
1948-49	,,	,,	,,	,,	,,	,,	3419.2	2869.8	2771.3	3107.4	3022.5	3953.0	6293.7	,,
1949-50	,,	,,	,,	,,	,,	,,	1858.1	1364.2	1242.7	1280.8	2003.0	2784.6	5314.2	,,
1950-51	,,	,,	,,	,,	,,	,,	1899.4	1404.7	1315.4	1441.7	2373.4	3209.1	6151.8	,,
1951-52	,,	,,	,,	,,	,,	,,	2275.1	1765.3	1651.0	1756.5	2650.8	3631.8	6237.3	,,
1952-53	,,	,,	,,	,,	,,	,,	2578.2	2116.1	2073.9	2444.0	2882.5	3815.3	6203.7	,,
1953-54	,,	,,	,,	,,	,,	,,	1436.6	951.6	870.6	948.5	1294.3	2082.5	5255.3	,,
1954-55	,,	,,	,,	,,	,,	,,	1923.3	1421.6	1333.2	1380.0	2079.6	2809.1	5246.4	,,
1955-56	,,	,,	,,	,,	,,	,,	1756.7	1262.0	1152.4	1199.5	1696.6	2791.0	5906.3	,,
1956-57	,,	,,	,,	,,	,,	,,	1919.2	1424.0	1329.2	1374.5	1912.9	2764.8	6254.2	,,
1957-58	,,	,,	,,	,,	,,	,,	1764.5	1272.6	1184.1	1245.4	1784.7	2652.9	6043.1	,,

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Table 12

COMPUTATION OF CANADIAN ENTITLEMENT FOR
1995-96 ALTERNATIVE OPERATING PLAN:

A. Optimum Power Generation in Canada and the U.S. (From 96-42)
B. Optimum Power Generation in the U.S. Only (From 96-12)
C. Optimum Power Generation in the U.S. and a 1/2 Million Acre-Feet Reduction in Total Canadian Treaty Storage (From 96-22)

Determination of Dependable Capacity Credited to Canadian Storage - MW

	(A)	(B)	(C)
Step II - Critical Period Avg. Generation 1/	8,894.2	8,894.9	8,861.8
Step III - Critical Period Avg. Generation 2/	7,113.5	7,113.5	7,113.5
Gain Due to Canadian Storage	1,780.7	1,781.4	1,748.3
Average Critical Period Load Factor in % 3/	75.18	75.18	75.18
Dependable Capacity Gain 4/	2,368.6	2,369.5	2,325.5
Canadian Share of Dependable Capacity 5/	1,184.3	1,184.8	1,162.8

Determination of Increase in Average Annual Usable Energy - Average MW

Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Annual Firm Hydro Energy 6/	8,800.1	8,801.0	8,768.2
Thermal Replacement Energy 7/	1,573.4	1,563.4	1,579.8
Other Usable Secondary Energy 8/	415.1	423.5	429.9
System Annual Average Usable Energy	10,788.6	10,787.9	10,777.9
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6,401.4	6,401.4	6,401.4
Thermal Replacement Energy 7/	2,214.1	2,214.1	2,214.1
Other Usable Secondary Energy 8/	903.9	903.9	903.9
System Annual Average Usable Energy	9,519.3	9,519.3	9,519.3
Average Annual Usable Energy Gain 9/	1,269.3	1,268.6	1,258.6
Canadian Share of Avg. Annual Energy Gain 5/	634.6	634.3	629.3

1/ Step II values were obtained from the 96-42, 96-12, and 96-22 studies, respectively.
2/ Step III values were obtained from the 96-13 study.
3/ Critical period load factor from Table 3.
4/ Dependable Capacity Gain credited to Canadian storage equals gain in critical period average generation divided by the average critical period load factor.
5/ One-half of Dependable Capacity or Usable Energy Gain.
6/ From 30-year average firm load served.
7/ Avg. secondary generation limited to Potential Thermal Displacement market.
8/ Forty percent (40%) of the remaining secondary energy.
9/ Difference between Step II and Step III Annual Average Usable Energy.

TABLE 13

SUMMARY OF POWER REGULATIONS
FROM 1995-96 ALTERNATIVE OPERATING PLAN

	BASIC DATA		STEP I			STEP II				STEP III			
PROJECTS	NUMBER OF UNITS	NOMINAL INSTALLED PEAKING CAPACITY MW	USABLE STORAGE 1000 AF	JANUARY PEAKING CAPABILITY MW	CRITICAL PERIOD AVERAGE GENERATION MW	USABLE STORAGE 1000 AF	JANUARY PEAKING CAPABILITY MW	CRITICAL PERIOD AVERAGE GENERATION MW	30 YEAR AVERAGE ANNUAL GENERATION MW	USABLE STORAGE 1000 AF	JANUARY PEAKING CAPABILITY MW	CRITICAL PERIOD AVERAGE GENERATION MW	30 YEAR AVERAGE ANNUAL GENERATION MW
<u>HYDRO RESOURCES</u>													
<u>CANADIAN</u>													
Mica			7,000			7,000							
Arrow			7,100			7,100							
Duncan			1,400			1,400							
Subtotal			15,500			15,500							
<u>BASE SYSTEM</u>													
Hungry Horse	4	328	3,161	328	99	3,008	186	112	103	3,008	328	192	104
Kerr	3	160	1,219	151	114	1,219	149	102	116	1,219	151	143	115
Thompson Falls	6	40	0	40	38	0	40	38	37	0	40	40	36
Noxon Rapids	5	554	231	536	148	0	554	133	202	0	554	171	202
Cabinet Gorge	4	230	0	230	100	0	230	87	116	0	230	108	117
Albeni Falls	3	49	1,155	29	28	1,155	30	26	27	1,155	40	28	29
Box Canyon	4	74	0	71	46	0	72	44	48	0	70	55	47
Grand Coulee	24+3SS	6,684	5,185	6,383	2,005	5,072	6,358	1,747	2,348	5,072	5,868	1,191	2,246
Chief Joseph	27	2,614	0	2,614	1,122	0	2,614	1,022	1,373	0	2,614	747	1,296
Wells	10	820	0	820	391	0	820	366	452	0	820	273	418
Rocky Reach	11	1,267	0	1,267	563	0	1,267	527	678	0	1,267	392	634
Rock Island	18	544	0	544	274	0	544	257	323	0	544	189	295
Wanapum	10	986	0	986	503	0	986	477	592	0	986	345	535
Priest Rapids	10	912	0	912	500	0	912	474	586	0	912	350	510
Brownlee	5	675	975	675	225	974	675	296	290	974	675	266	290
Oxbow	4	220	0	220	83	0	220	117	118	0	220	120	118
Ice Harbor	6	693	0	693	217	0	693	231	300	0	693	192	300
McNary	14	1,127	0	1,127	655	0	1,127	631	794	0	1,127	503	745
John Day	16	2,484	535	2,484	928	0	2,484	905	1,229	0	2,484	716	1,193
The Dalles	22+2F	2,074	0	2,074	738	0	2,074	717	977	0	2,074	564	957
Bonneville	18+2F	1,147	0	1,147	556	0	1,147	547	677	0	1,147	456	646
Kootenay Lake	0	0	673	0	0	673	0	0	0	673	0	0	0
Chelan	2	54	677	52	36	676	51	38	45	676	52	51	42
Coeur d'Alene Lake	0	0	223	0	0	223	0	0	0	223	0	0	0
Total Base System Hydro		23,736	29,535	23,383	9,379	28,500	23,235	8,894	11,411	13,000	22,896	7,114	10,875

ADDITIONAL STEP I PROJECTS									
Libby	5	604	4,980	572	187				
Boundary	6	1,055	0	855	368				
Spokane River Plants	24	156	104	155	91				
Hells Canyon	3	450	0	450	180				
Dworshak	3	460	2,015	460	183				
Lower Granite	6	932	0	932	215				
Little Goose	6	932	0	932	215				
Lower Monumental	6	932	0	932	204				
Pelton, Rereg., and Round Butte	7	423	274	419	123				
Subtotal		5,944	7,373	5,707	1,766				
THERMAL RESOURCES 1/									
Small Existing Thermal Plants 2/				1,656	542				
Centralia #1 & #2				1,280	1,146				
Jim Bridger #1, #2, #3, & #4				2,021	1,667				
Colstrip #1,#2,#3,#4				1,297	1,006				
Trojan				1,104	797				
Boardman				530	404				
Valmy				242	199				
WNP #2				1,095	731				
Total Thermal Resources				9,225	6,492	9,225	6,517	9,225	6,818
RESERVES 3/				(2,394)	0	(1,926)	0	(1,822)	0
TOTAL RESOURCES				35,921	17,637	30,534	15,411	30,299	13,732
LOADS									
ESTIMATED LOAD PACIFIC NORTHWEST AREA 4/				29,925	19,021	24,071	15,411	20,273	13,732
Firm Exports				1305	869				
Surplus Firm Exports				0	219				
Firm Imports				(1,018)	(212)				
Miscellaneous Contracts				(275)	(311)				
Other Coordinated Hydro		3,183	5,576	(2,718)	(1,037)				
Independent Hydro Resources		1,988	4,342	(1,469)	(821)				
Estimated Hydro Maintenance				1,561	11				
Added Cons./Resources				0	(122)				
TOTAL STEP I LOADS				27,291	17,637				
SURPLUS				8,630	0	6,463	0	10,026	0
CRITICAL PERIOD Starts				September 1, 1928		September 1, 1943		November 1, 1936	
Ends				February 29, 1932		April 30, 1945		April 30, 1937	
Length (Months)				42 Months		20 Months		6 Months	
Study Identification				95-41		95-42		95-13	

1/ Thermal energy capabilities are based on an annual plant factor of 60 percent the first full year of operation and 75 percent thereafter unless specified differently by project owner. These annual plant factors include deductions for energy resources and scheduled maintenance.

2/ Sm-Existing Thermal Plant also includes Combustion Turbines.

3/ Peak reserves are 8 percent of peak load from Table 3; energy reserve deductions have been included in thermal plant energy capability.

4/ Step II or III Peak Load is equal to the Step II or III Annual Average Load, multiplied by the ratio of the PNW area Jan. Peak Load to the Annual Average Load from Table 3.

TABLE 14

DETERMINATION OF DISPLACEABLE THERMAL MARKET
FOR 1995–96 ALTERNATIVE OPERATING PLAN
(Energy in Average MW)

	Aug 1–15	Aug 16–31	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	March	Apr 1–15	Apr 16–30	May	June	July	Annual Average
THERMAL RESOURCES															
1. Total PNW Thermal Resources	6907.0	6907.0	6684.0	7095.0	7141.0	7140.0	7149.0	6953.0	6114.0	6088.0	4343.0	3764.0	5739.0	6949.0	6402.0
2. Minimum Thermal Generation	1666.0	1666.0	1515.0	1703.0	1831.0	1831.0	1831.0	1740.0	1502.0	1419.0	1315.0	1176.0	1364.0	1689.0	1601.0
3. Displaceable PNW Thermal Resources	5241.0	5241.0	5169.0	5392.0	5310.0	5309.0	5318.0	5213.0	4612.0	4669.0	3028.0	2588.0	4375.0	5260.0	4801.0
4. Displaceable PSW Thermal Imports	0.0	0.0	0.0	0.0	0.0	0.0	143.0	285.0	285.0	285.0	0.0	0.0	0.0	0.0	69.9
5. Total Displaceable Thermal Resources	5241.0	5241.0	5169.0	5392.0	5310.0	5309.0	5461.0	5498.0	4897.0	4954.0	3028.0	2588.0	4375.0	5260.0	4870.9
SYSTEM SALES															
6. Total Exports/Incl Exchanges	1086.0	1086.0	1047.0	781.0	705.0	749.0	746.0	727.0	730.0	821.0	885.0	1046.0	1146.0	1229.0	904.8
7. Total Export Exchanges	377.0	377.0	367.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	116.0	367.0	375.0	196.8
8. Exports w/o Exchanges	709.0	709.0	680.0	673.0	597.0	641.0	638.0	619.0	622.0	713.0	777.0	930.0	779.0	854.0	708.1
9. Additional Net Exchange Exports	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0
10. Net Exchanges/Exports	810.0	810.0	781.0	774.0	698.0	742.0	739.0	720.0	723.0	814.0	878.0	1031.0	880.0	955.0	
11. Firm Surplus Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3000.0	0.0	0.0	
12. Total System Sales	810.0	810.0	781.0	774.0	698.0	742.0	739.0	720.0	723.0	814.0	878.0	4031.0	880.0	955.0	1063.9
13. Uniform Average Annual System Sales	1063.9	1063.9	1063.9	1063.9	1063.9	1063.9	1063.9	1063.9	1063.9	1063.9	1063.9	1063.9	1063.9	1063.9	
PNW THERMAL DISPLACEMENT MARKET =	4177.1	4177.1	4105.1	4328.1	4246.1	4245.1	4397.1	4434.1	3833.1	3890.1	1964.1	1524.1	3311.1	4196.1	3807.1

NOTES:

Line 1 = Total Thermal Resources from the Step I study includes those located in the PNW and those not located in the PNW which meet Step I system load.
Line 2 = Minimum generation requirement for above resources.
Line 3 = Displaceable Thermal Resources from the Step I study. Line 1 minus line 2.
Line 4 = There is only one displaceable thermal import that is not an exchange: SCE to BPA, Optional Energy.
Line 5 = Line 3 plus line 4.
Line 6 = Total Exports including Exchanges consists of all firm contract sales of energy exported to meet non–PNWA load.
Line 7 = These exports are part of contracts that include corresponding seasonal exchange imports.
Line 8 = Sum of the Step I study firm contract sales of energy exported to meet non–PNWA Loads minus the exchanges. Line 6 minus line 7.
Line 9 = This is an additional export, the portion of the seasonal exchange contracts not balanced by a corresponding import.
Line 10 = Line 8 plus line 9.
Line 11 = Firm Surplus Energy Sales in the Step I study assumed to be exported to PSW.
Line 12 = Line 10 plus line 11.
Line 13 = Yearly Average Annual Sales, calculated from Line 12.
PNW Thermal Displacement Market is the Total Displaceable Thermal Resources minus Uniform Average Annual System Sales. Line 5 minus line 13.

TABLE 15

DETERMINATION OF LOADS FOR
1995–96 STEP I, II, AND III STUDIES
FOR ALTERNATIVE OPERATING PLAN

LOAD OF THE PACIFIC NORTHWEST AREA					STEP I STUDY					STEP II STUDY		STEP III STUDY		
					ENERGY LOAD		PEAK LOAD							
Period	PNW Area Energy Load 1/ aMW	Annual Energy Load Shape Percent	Peak Load MW	Load Factor Percent	Firm Surplus aMW	Total MWa 2/	Firm Surplus MW	Total MW	Thermal Installations 3/ aMW	Total Load 4/ aMW	Hydro Load 5/ aMW	Total Load 4/ aMW	Hydro Load 5/ aMW	Period
Aug. 1–15	17389	92.01	21746	79.96	0	17389	0	21746	6907	13987.5	7080.5	11780.4	4873.4	Aug. 1–15
Aug. 16–31	17311	91.60	21706	79.75	0	17311	0	21706	6907	13924.8	7017.8	11727.5	4820.5	Aug. 16–31
Sept. 1–15	17064	90.29	22211	76.83	0	17064	0	22211	6684	13726.1	7042.1	11560.2	4876.2	Sept. 1–15
Sept. 16–30	17024	90.08	22211	76.65	0	17024	0	22211	6684	13593.9	7009.9	11533.1	4849.1	Sept. 16–30
October	17722	93.78	24305	72.92	0	17722	0	24305	7095	14255.4	7160.4	12006.0	4911.0	October
November	19762	104.57	26780	73.79	0	19762	0	26780	7141	15896.3	8755.3	13388.0	6247.0	November
December	21274	112.57	28954	73.48	0	21274	0	28954	7140	17112.6	9972.6	14412.3	7272.3	December
January	21791	115.31	29925	72.82	0	21791	0	29925	7149	17528.4	10379.4	14762.6	7613.6	January
February	20946	110.84	28867	72.56	0	20946	0	28867	6953	16848.7	9895.7	14190.1	7237.1	February
March	19350	102.39	25982	74.47	0	19350	0	25982	6114	15564.9	9450.9	13108.9	6994.9	March
April 1–15	18435	97.55	24935	73.93	0	18435	0	24935	6088	14828.9	8740.9	12489.0	6401.0	April 1–15
April 16–30	18532	98.06	25019	74.07	0	18532	0	25019	4343	14906.9	10563.9	12554.7	8211.7	April 16–30
May	17775	94.06	23611	75.28	3000	20775	4720	28331	3764	14298.0	10534.0	12041.9	8277.9	May
June	17749	93.92	22467	79.00	0	17749	0	22467	5739	14277.1	8538.1	12024.3	6285.3	June
July	17649	93.39	22058	80.01	0	17649	0	22058	6949	14196.6	7247.6	11956.5	5007.5	July
Annual Average =	18898.2	100.00		75.43	254.8	19153.0		Ann Avg	6402.0	15201.5	8799.5	12802.8	6400.8	Annual Avg.
Critical Period Avg =	19020.8			75.18	218.5	19239.3		CP I	6491.4	15410.7	8894.2	13731.6	7113.5	Crit.Per.Avg.
Step II Crit. Per. Avg =	19158.2							CP II	6516.5					
Step III Crit. Per. Avg=	20269.2							CP III	6618.1	Input 6/=	8894.2	Input 6/=	7113.5	
											*********		***********	
August 1–31	17350.0	91.81	21726.0	79.86	0	17350.0		21726.0	6907.0	13956.1	7049.1	11754.0	4847.0	Aug. 1–31
September 1–30	17044.0	90.19	22211.0	76.74	0	17044.0		22211.0	6684.0	13710.0	7026.0	11546.6	4862.6	Sept. 1–30
April 1–30	18483.5	97.81	24977.0	74.00	0	18483.5		24977.0	5215.5	14867.9	9652.4	12521.9	7306.4	Apr. 1–30

Notes: 1. The PNW Area load does not include the exports, but does include pumping. The computation of the load shape for Step II/III studies used these loads.
2. Step I study loads also include exports which are shown on Table 4, Line 6.
3. The thermal installations include large thermal, combustion turbines and small existing thermal.
4. The total firm load for the Step II/III studies is computed to have the same shape as the load of the Pacific Northwest Area.
5. The hydro load is equal to the total load minus the Step I study thermal installations.
6. Input is the critical period average generation for the Step II/III hydro studies used to calculate the residual hydro loads.

Table 16

Comparison of 1995-96 Alternative Operating Plan to 1995-96 Assured Operating Plan and Previous Alternative Operating Plans

	Alternative Plans 1993-94	Alternative Plans 1994-95	Alternative Plans 1995-96	Assured 1995-96
Mica Target Operation (ksfd or cfs)				
Aug 1	3456.2	3456.2	3456.2	3456.2
Aug 2	Full	Full	Full	Full
Sep	Full	Full	Full	Full
Oct	Full	11000	11000	3428.4
Nov	14000	3185.5	3185.5	22000
Dec	22000	21000	21000	24000
Jan	27000	27000	27000	27000
Feb	25000	23000	23000	25000
Mar	24000	22000	22000	25000
Apr 1	22000	156.2	156.2	24000
Apr 2	15000	0.0	0.0	14000
May	12000	10000	10000	10000
Jun	10000	10000	10000	10000
Jul	3256.2	3356.2	3356.2	3356.2
Canadian Treaty CRC1 Storage Draft (ksfd)				
Nov 1928 (-41)	583.7	707.6	707.6	1272.6
Apr 1929 (-41)	7074.8	7451.5	7451.5	7801.6
Jul 1929 (-41)	1041.6	876.8	876.8	1140.5
Aug 1929 (-41)	704.9	582.7	582.7	1060.4
Nov 1928 (-11)	303.5	714.6	714.6	1275.3
Jul 1929 (-11)	1062.3	925.0	925.0	1142.8
Step I Study Gains and Losses due to Re-operation (MW)				
U.S. Firm Energy	-1.8	-6.5	-6.5	-4.4
U.S. Dep. Capacity	+23.0	0.0	0.0	+2.0
U.S. Sec. Energy	+6.2	+13.5	+13.5	+2.9
BCH Firm Energy	+51.8	+55.1	+55.1	+56.0
BCH Dep. Capacity	-18.0	-8.0	-8.0	+16.0
BCH Sec. Energy	-30.8	-34.5	-34.5	-38.3
Secondary Load (MW)				
Aug 1	10655	11475	11475	11475
Aug 2	10655	11475	11475	11475
Sep	10092	11466	11466	11466
Oct	10237	12021	12021	12021
Nov	10083	12272	12272	12272
Dec	10074	12443	12443	12443
Jan	10914	12633	12633	12633
Feb	10765	12641	12641	12641
Mar	10405	11909	11909	11909
Apr 1	10235	11817	11817	11817
Apr 2	10933	11573	11573	11573
May	7114	8114	8114	8114
Jun	10079	11236	11236	11236
Jul	10740	11590	11590	11590

Table 17

Comparison of 1995-96 Alternative Operating Plan
to 1995-96 Assured Operating Plan
and Previous Alternative Operating Plans

	Alternative Plans			Assured
	1993-94	1994-95	1995-96	1995-96
PNW Area Avg. Annual Load (MW)	18370	18898	18898	18898
- Avg. Annual / Jan. Load (%)	86.73	86.72	86.72	86.72
- Avg. C.P. Load Factor (%)	72.37	75.18	75.18	75.18
- Avg. Annual Firm Exports (MW)	969	905	905	905
- Avg. Annual Firm Surplus (MW)	255	255	255	255
Thermal Resource (MW)				
- January Peak Capability	9220	9225	9225	9225
- C.P. Energy	6256	6491	6491	6491
- C.P. Minimum Energy	1881	1621	1621	1621
- Avg. Annual System Export Sales	1146	1064	1064	1440
- Avg. Annual Displaceable Market	3158	3807	3807	3462[1]
Installed Hydro Capacity (MW)	29745	29680	29680	29680
- Base System	23806	23736	23736	23736
Step I/II/III C.P. (months)	42/20/5.5	42/20/6	42/20/6	42/20/6
Base Streamflows at The Dalles (cfs)				
- Step I 50-yr Average	178235	179502	179502	179502
- Step I C.P. Average	112843	113177	113177	113177
- Step II C.P. Average	99548	100146	100146	100146
- Step III C.P. Average	57498	64733	64733	64733
Capacity Benefits (MW)				
- Step II C.P. Generation	8879.5	8894.2	8894.2	8892.9
- Step III C.P. Generation	7036.3	7113.5	7113.5	7113.5
- Gain (Step II minus Step III)	1843.2	1780.7	1780.7	1779.4
- Canadian Entitlement	1273.4	1184.3	1184.3	1183.4
- Change due to Mica Re-op.	-3.1	-0.5	-0.5	+0.7
- Benefit in Sales Agreement	755.0	666.0	576.0	576.0
Energy Benefits (Avg. MW)				
- Step II Firm Hydro	8839.6	8800.1	8800.1	8928.3
- Step II Thermal Displacement	1366.4	1573.4	1573.4	1422.3
- Step II Other Usable	461.5	415.1	415.1	421.0
- Step II Total	10667.5	10788.6	10788.6	10771.6
- Step III Firm Hydro	6485.2	6401.4	6401.4	6401.4
- Step III Thermal Displacement	1943.1	2214.1	2214.1	2123.8
- Step III Other Usable	967.4	903.9	903.9	940.0
- Step III Total	9395.7	9519.3	9519.3	9465.2
- Canadian Entitlement	635.9	634.6	634.6	653.2
- Change due to Mica Re-op.	+1.4	+0.3	+0.3	-2.0
- Benefit in Sales Agreement	293.0	279.0	268.0	268.0
Step II Peak Capability (MW)	30577	30534	30534	30530
Step II Peak Load (MW)	24430	24071	24071	24069
Step III Peak Capability (MW)	30429	30299	30299	30299
Step III Peak Load (MW)	20593	20273	20273	20273

Notes: 1. Applicable in shift years only.

1995-96
DETERMINATION OF
DOWNSTREAM POWER BENEFITS
30-YEAR HYDRO
GENERATION - MW
(ALTERNATE PLAN)