Columbia River Treaty Past and Future

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ABSTRACT

The 1964 Columbia River Treaty (CRT) between Canada and the United States of America required the construction and operation of three large dams in the upper Columbia River basin in British Columbia, Canada, and allowed the U.S. to construct a fourth dam in Montana. CRT dams more than doubled the amount of reservoir storage in the basin, which has greatly increased downstream hydropower generation and flood control, providing billions of dollars of benefits for the two countries. The CRT is known throughout the world as one of the most successful transboundary water treaties based on equitable sharing of downstream benefits. The CRT has proved durable and has evolved through numerous technical issues and changing societal values, which have added to and shaped the implementation processes and procedures.

The CRT has several provisions that are enabled only after September 2024, including changes to flood control obligations and an option for either government to terminate the CRT if at least 10-years prior notice is given. These provisions, and changing needs for hydropower, fish, and other water uses, make the future of the CRT uncertain. The Canadian and U.S. Entities, the agencies that implement the CRT, have initiated a 2014/2024 Columbia River Treaty Review process for Phase I Studies to examine the CRT's 2024 provisions, develop hydroregulation studies that help understand the post-2024 conditions, and inform the process for developing future studies.

1. INTRODUCTION

The Columbia River Treaty[1] between Canada and the United States of America, signed in 1961 and ratified in 1964, required the construction and operation of three large dams in the upper Columbia River basin in British Columbia, Canada, and gave the U.S. an option to build a fourth dam in Montana with a reservoir that extends into Canada. The operation of CRT dams is designed to provide flood control and hydropower benefits in both countries, which makes possible other benefits as well. CRT dams more than doubled the amount of Columbia River basin reservoir storage,[2] which transformed annual stream flows by storing the spring runoff for gradual release during fall and winter months or in subsequent years. This eliminated major flood damages for all but the most extreme events, which hasn't happened in the entire Treaty operating history. The smoothing of annual stream flows greatly increased downstream hydropower generation and has provided billions of dollars of power benefits in both countries, although annual U.S. power benefits from Treaty storage have decreased over the last 25 years due to increasing U.S. fishery constraints.

The CRT was negotiated during an era when more than a dozen large dams were completed in the Columbia River basin; mainly for power, flood control, navigation, and irrigation. Several (e.g. Hungry Horse) had transboundary effects, but no agreement to share costs or cross-border benefits. There were examples outside the region of transboundary cooperation. The 1959 completion of the St. Lawrence Seaway served as a prime example of cooperative development of transboundary projects and of using shared hydropower benefits to enable other benefits.

The CRT enabled a wide range of related benefits that affect British Columbia and the western U.S. including additional downstream hydropower projects, additional generators at most downstream Columbia River dams, two major regional power coordination agreements, and Congressional approval for: the construction of the electrical intertie between California and the Pacific Northwest, the sale of federal hydropower to California, and regional preference legislation for federal hydropower.

Today, the CRT is known throughout the world as one of the best and most successful examples of a transboundary water Treaty based on equitable use of cross-border streamflows. This concept was relatively new when the CRT was signed but is now accepted by many nations. The CRT has proved durable, and has evolved through numerous technical issues and changing societal values. The two countries have been able to negotiate additional mutual benefits in areas beyond power and flood control, especially to mitigate fishery impacts.

Figure 1: Map of Columbia River Basin, courtesy of the Army Corps of Engineers

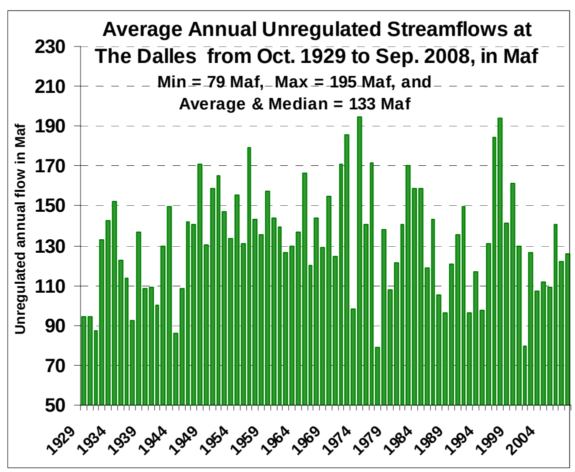
The CRT has several provisions that are enabled only after September 2024 (60 years after ratification), including changes to flood control obligations and an option to terminate the CRT. These provisions, and changing needs for hydropower, fish and wildlife, and other water uses, make the future of the CRT uncertain.

The purpose of this article is to summarize the CRT provisions, its history, and describe the many issues that have shaped its implementation over the last 45 years, with the hope it might provide some insight on the future of this important coordination agreement.

2. COLUMBIA RIVER BASIN

The Columbia River basin (Figure 1), at 259,500 square miles, is larger than France. It includes more than half of Washington and Oregon, nearly all of Idaho, and portions of Montana, Wyoming, Utah, and Nevada. About 15 percent of the basin is in British Columbia (B.C.) Canada, and another 8 percent within the U.S. is the source of flows into B.C. from the Kootenai and Pend Oreille Rivers that eventually join the Columbia River.

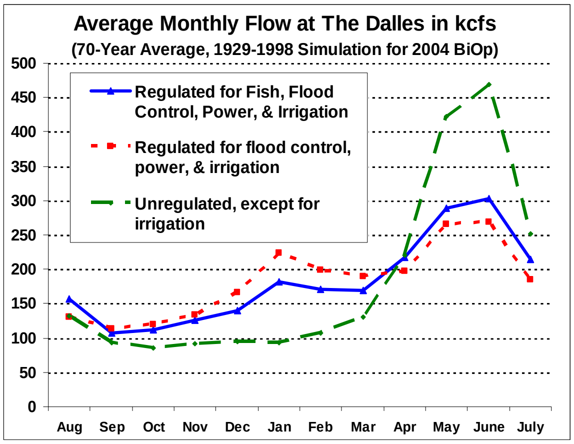
Figure 2: Annual unregulated stream flows



The Columbia River is the fourth largest river in North America, based on estimated average annual flow at its mouth of about 198 million acre-feet (Maf). The flow is normally measured for power and flood control purposes at The Dalles, Oregon,[3] where the average annual unregulated[4] flow of 133 Maf can vary from year to year by up to +/- ~45 percent (Figure 2). The Columbia River has about 10 times the flow of the Colorado River, and about 70 percent of the St. Lawrence River at Cornwall. The Columbia River is sometimes called the most powerful river in North America, with over 37,000 MW[5] of installed hydropower capacity. The average annual hydropower energy in the U.S. portion of the basin and adjoining four-state region is about three-fourths the regional electrical load.

About 38 percent of the average annual flow and up to 50 percent of the peak flows at The Dalles come across the Canadian border. Historical daily stream flows at the border, which includes the Kootenay and Pend Oreille basins, have varied from as low as 14 thousand cubic-feet per second (kcfs) to over 550 kcfs. The total usable reservoir storage above The Dalles before the CRT was about 18 Maf, which is less than 15 percent of the average annual runoff. Historical daily streamflows at The Dalles varied from as low as 36 kcfs to as high as 1,240 kcfs. With little storage and a wide variation in streamflows, the Columbia River caused significant flood damage and hydropower problems that have been largely resolved by building storage dams. Today, the Columbia River basin has more than 55 Maf of reservoir storage, which is 41 percent of the average annual flow at The Dalles. Actual use of storage today is often much less due to constraints that mitigate fishery impacts (see Figure 3). This relatively small percentage of storage allows only limited control of the Columbia compared to other major rivers. The Missouri and Colorado, for example, have two to three times more storage than average annual flow.

Figure 3: Unregulated vs. regulated flows at The Dalles, with and without modern nonpowe constraints



3. CRT ORIGIN

The 1909 Boundary Waters Treaty established principles and procedures affecting U.S./Canada boundary waters and created a permanent International Joint Commission (IJC) to study and help resolve problems relating to use of boundary waters. The Boundary Waters Treaty affirmed the accepted principle of that era for the exclusive jurisdiction of the upstream country to divert or regulate cross-border flows, and the downstream country owes nothing for any beneficial upstream regulation and has limited recourse for any adverse effects. However, the Boundary Waters Treaty made some progress in addressing adverse effects. It requires IJC approval for changes to boundary water levels, promises unrestricted navigation, prohibits pollution that causes injury, and gives citizens in each country the same rights and remedies for water level and flow related injuries as citizens in the country causing injury.

Figure 4: May 31, 1948 Oregonian newspaper. ©*1948 The Oregonian. All rights reserved. Reprinted by permission.*

In 1944, Canada and the U.S. requested that the IJC determine "whether a greater use than is now being made of the waters of the Columbia River System would be feasible and advantageous." Detailed studies began after a 1948 flood severely damaged communities from Trail, B.C., to the lower Columbia and destroyed Vanport (Figure 4), the second largest city in Oregon. What followed was 11 years of discussions and analysis, two requests by the U.S. for IJC approval of Libby dam, two proposals by U.S.

companies to build Canadian dams, Committee hearings in the U.S. Senate and Canadian Parliament, much posturing for a better deal including talk of a Canadian diversion of the Columbia into the Fraser River, and a gradual acceptance by the U.S. of the idea of sharing the downstream U.S. benefits with Canada. Finally, in December 1959 the IJC reported[6] its study results and recommended principles for determining and apportioning benefits from the cooperative use of storage. Guided by those principles, formal negotiations[7] began in February 1960, with nine sessions that led to the signing of the CRT by President Eisenhower and Prime Minister Diefenbaker on January 17, 1961.

The U.S. Senate approved[8] the CRT in March 1961, but ratification by Canada was delayed until Sept. 16, 1964, when three conditions set by the British Columbia government were satisfied: 1) Canada and the U.S. agreed to a CRT Protocol that clarified, expanded, and limited some of the CRT's provisions; 2) the province of B.C. and the Canadian federal government signed an agreement that allowed the sale of the Canadian share of the CRT downstream power benefits and defined and clarified issues of authority and responsibility between them; and 3) the Canadian share of the U.S. downstream power benefits was sold to a consortium of U.S. electric utilities for 30 years, providing funds expected to be sufficient for B.C. to construct their CRT dams.

Table 1- Treaty Projects

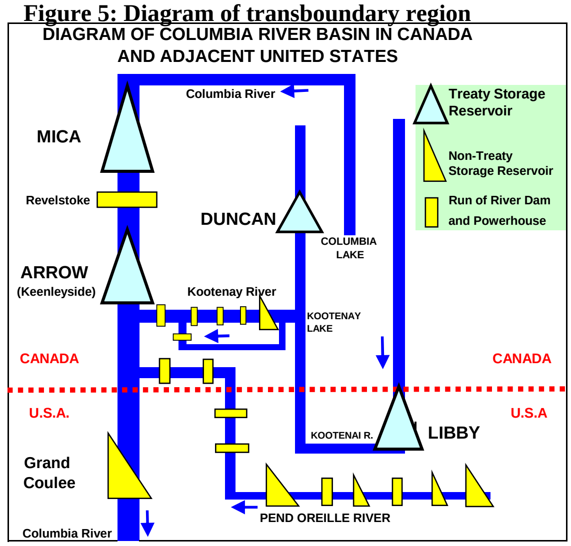
	Mica	Arrow	Duncan	Libby
Basin area, mi^2	8108	14093	925	9070
Reservoir area, mi^2	168	204	28	73
Max reservoir depth, ft	605	171	127	370
Treaty Storage, Maf	7.0*	7.1*	1.4*	4.98
Non-Treaty Stor. Maf	5.0	0.25	0	0
Avg. annual flow, kcfs	20.6	40.5	3.6	8.1
Avg. ann. energy, MW	822	103	0	233
Powerhouse size, MW	1792	180	0	600
Max power flow, kcfs	43	39	0	25

* Exact value, all other data approximate.

4. TREATY PROJECTS

The CRT required Canada to build and operate three dams on the Columbia River and a tributary in Canada, the Duncan River. The dams would create 15.5 Maf of reservoir storage for power generation and flood control benefits in Canada and downstream in the United States. The Canadian storage projects are Duncan Dam (Duncan Lake), which began operation in 1967, followed by Keenleyside Dam (Arrow Lakes) in 1968, and Mica Dam (Kinbasket Lake) in 1973 (Table 1 and Figure 5). The CRT also allowed the U.S. to construct Libby Dam on the Kootenai River in Montana for flood control and other purposes in the U.S. Libby Dam began operation in 1972. Its 90-mile long reservoir (Koocanusa Lake)[9] extends 42 miles into Canada, and downstream flows return to Canada before joining the Columbia near Castlegar, B.C. All projects except Duncan now include powerhouses.

Figure 5: Diagram of transboundary region



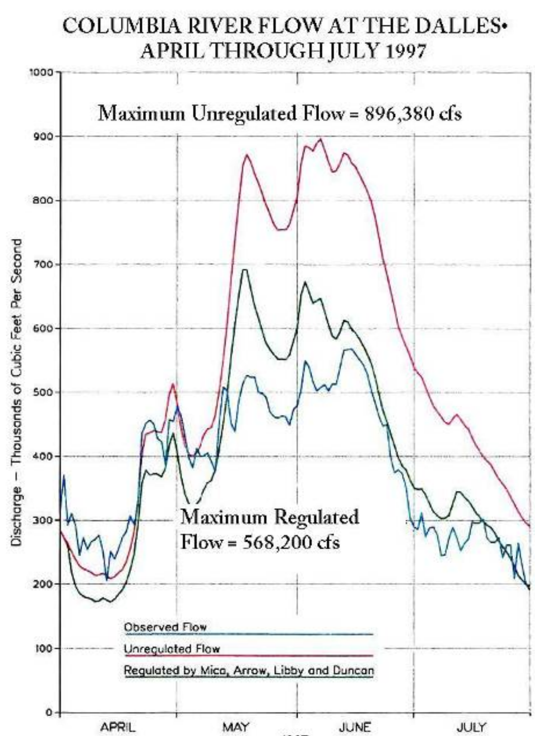
British Columbia decided to build Mica dam higher than required by the CRT, which increased Mica's power-generating capability, and created an additional 5 Maf of Non-Treaty storage (discussed in section 13.1). Since completion of the Treaty projects in the early 1970's, B.C. Hydro has added a canal and powerhouse on the Kootenay River (1975), a large run-of-river power project at Revelstoke (1984), and a canal and powerhouse to Keenleyside (2002).

5. FLOOD CONTROL BENEFITS

The CRT requires Canada to operate at least 8.45 Maf of storage to minimize flood damages in both Canada and the U.S. until September 2024 (60 years after CRT ratification). As compensation, the U.S. made three lump-sum payments totaling $64.4 million to Canada when the dams were completed. The amount was based on an estimate of one-half of the present value of future U.S. flood damages prevented. In addition, Canada must operate all remaining Canadian storage if "Called Upon" by the U.S. to meet forecast flood control needs in the U.S. that cannot adequately be met by the Canadian 8.45 Maf and U.S. flood control facilities. Prior to 2024, the Called Upon option is available only in the case of potential floods that could result in peak discharges in excess of 600 kcfs at The Dalles. The U.S. must pay $1.875 million for each of the first four Called Upon requests. This option has never been used, mainly because the power operation often drafts reservoirs deeper and essentially provides additional flood control.

The U.S. must coordinate the operation of Libby for flood control in Canada, but there are no payments for those benefits. Libby's operation provides substantial flood control benefits near Bonners Ferry Idaho, at Kootenay Lake in British Columbia, and downstream in the U.S.

Figure 6: Peak Flows at The Dalles



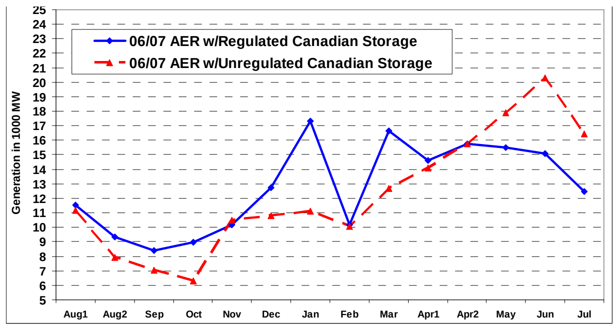
After 2024, Canada's obligation to provide up to 8.45 Maf for flood control ends. However, the U.S. still may call upon flood control assistance from Canada for potential floods that cannot be adequately controlled by all related U.S. reservoirs that would be effective in controlling flooding on the Columbia River in the U.S. This is limited to no greater degree of flood control after 2024 than before 2024. For each request, the U.S. must pay the operating costs and any economic losses in British Columbia arising directly from foregoing alternative uses of the Called Upon storage flood control operation.

Since record keeping began in 1858, there have been four years with peak unregulated Columbia River streamflows at The Dalles exceeding 1,000 kcfs: 1894, 1948, 1972, and 1974. The first two of these floods caused catastrophic damages. Prior to completion of Grand Coulee dam in 1941, about one-half of all years experienced peak flows exceeding 600 kcfs, which is considered the beginning of major flood damage in the lower Columbia River. From 1941 until 1973, one-third of the years had peak regulated flows over 600 kcfs. Since the CRT dams were completed in 1973, there has never been a peak regulated flow over 600 kcfs. The U.S. Army Corps of Engineers does not calculate damages prevented by Canadian storage, but does estimate that the effect of Columbia basin reservoir regulation has reduced flood damages in the U.S. during 1972, 1974, and 1997 by about $260, $306, and $379 million, respectively.[10] Based on the proportion of active flood control storage, the Treaty projects may have provided more than half of those benefits. Figure 6 shows that 1997 flows, with the highest volume runoff since 1894, were regulated to less than 600 kcfs.

6. POWER BENEFITS

The operation of CRT storage creates hydropower benefits in Canada and the U.S. by reshaping streamflows into months where power is more valuable, reducing spill, enabling higher reservoir levels, and supplementing low inflows with releases of up to 15.5 Maf of Canadian storage and 5 Maf of Libby storage. The CRT requires that the downstream power benefits in the U.S. due to the operation of Canadian storage be shared equally between the two countries. The CRT recognizes that actual power benefits will vary a great deal from year to year, depending on reservoir inflows and storage levels, power loads, and many other factors. Thus, the CRT includes procedures that enhance, stabilize, and protect Canada's share which is called the Canadian Entitlement. These procedures estimate the expected average benefit and exclude or limit many of the factors that might reduce the benefit calculation, especially additional U.S. reservoirs, U.S. fishery constraints, and the California–Pacific Northwest electrical intertie. Delivery of the Canadian Entitlement to British Columbia is a firm obligation of the U.S. government. The amount is determined annually five years in advance and is not adjusted for actual benefits realized. The Canadian Entitlement computed for the August 2010 through July 2011 operating year is 535.7 MW average annual energy, delivered at rates up to 1,316 MW.

Figure 7: U.S. Coordinated System Hydro generation with and without Canadian Treaty storage operation.



The real incremental U.S. power benefits are not measured. CRT storage has such a large and pervasive impact on the U.S. system operation that its absence would significantly affect the operation of many other dams, the need for extra-regional imports and exports, the construction and operation of other generating resources, and even system loads and power markets. Thus, any benefit analysis would be highly speculative. For information purposes only, the CRT Operating Committee makes a rough estimate each year of the impact on downstream U.S. power generation. This estimate is made with and without the regulation of Canadian CRT storage, based on studies that include minimum flow and spill requirements for U.S. fishery objectives. The study results have varied over the past dozen years from as low as 73 to over 923 average annual MW. Figure 7 shows how the results vary within a typical year (2007). The market value of the power was not estimated in this analysis.

The U.S. must coordinate the operation of Libby for power benefits downstream in Canada. But the downstream power benefits in Canada and the U.S. from the operation of Libby are not shared or measured. Instead, they belong to the country in which they occur. Similarly, the cost incurred by the U.S. to build and operate Libby, and the Canadian costs to obtain and clear the land flooded by Libby reservoir, were not shared.

7. TREATY GOVERNANCE

The CRT established the U.S. and Canadian Entities as the implementing agencies for each country. The Canadian government appointed British Columbia Hydro and Power Authority (the provincial electric utility) as the Canadian Entity. President Lyndon Johnson defined the U.S. Entity as the Administrator of the Bonneville Power Administration (BPA)[11] and the

Northwestern Division Engineer of the U.S. Army Corps of Engineers (Corps). An agreement between the Canadian federal government and the province of British Columbia assigns most of the CRT rights and obligations to B.C. The authority and duties of the U.S. Entity are defined solely by the CRT and are distinctly separate from BPA and the Corps, although all U.S. Entity activities are performed by staff from the two agencies. The Entities have established Coordinators, Secretaries, an Operating Committee, and a Hydro-Meteorological Committee to perform most of the CRT activities.

The CRT also established a Permanent Engineering Board to review Entity actions for consistency with CRT objectives, to assist the Entities in resolving technical and operational disputes, and to report annually to the governments any deviations from the operating plans and the results being achieved under the CRT. Reports are directed to the U.S. Secretary of State and the Canadian Minister of Natural Resources. Two Permanent Engineering Board members and two alternates are appointed by each government. U.S. members are appointed by the Secretaries of Army and Energy, and Canadian members are appointed by the governments of Canada and British Columbia. Except for questions on the need for Called Upon flood control and the right to require Entity reports, the CRT does not give the Permanent Engineering Board authority to direct the Entities actions. However, the CRT states that Board reports are prima facie evidence of the facts therein contained, and shall be accepted unless rebutted by other evidence. A Permanent Engineering Board Engineering Committee, consisting of personnel from related agencies and contractors, assists the Board in reviewing Entity actions.

Disputes between the Entities may be referred to the International Joint Committee for a decision or to an Arbitration Tribunal if the International Joint Committee does not respond within three months; neither has ever been used. Instead, all disputes have been resolved either through negotiation by the Entities, sometimes with assistance of the Permanent Engineering Board, or rarely, with assistance of the British Columbia government, the Canadian federal Ministry of Foreign Affairs and Trade, and the U.S. Departments of State, Army, and Energy.

8. OPERATING PLANS

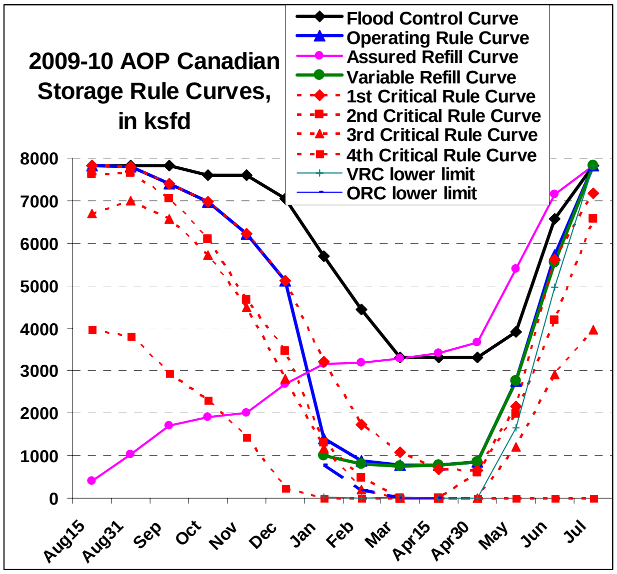
The CRT directs the U.S. Entity to develop, in consultation with the Canadian Entity, a Flood Control Operating Plan that guides the operation of Canadian storage to prevent flood damage in both Canada and the U.S. Last updated in 2003, the Flood Control Operating Plan is part of a coordinated operation of U.S. and Canadian projects. The goal is to reduce to non-damaging levels the flows at all potential flood damage areas insofar as possible, and to regulate larger floods that cannot be controlled to non-damaging levels to the lowest possible level. The flood control operating plan is based on storage reservation diagrams that determine draft of Canadian storage during the winter and early spring as a function of the volume runoff forecast. Refill is guided by a variable target flow that maximizes flood reduction and assure reservoir refill.

The CRT requires that the Entities prepare annually an Assured Operating Plan for Canadian Storage and the resulting Determination of Downstream Power Benefits. These power operating plans are created for the sixth succeeding operating year. The Assured Operating Plans are designed to achieve an optimum power operation in both Canada and the U.S. The Determination of Downstream Power Benefits calculates the Canadian Entitlement. It also determines the year-to-year limit of allowable decrease in Entitlement due to operation of Canadian storage for optimum power in both Canada and the U.S. instead of only in the U.S.

The CRT includes general procedures for creating and implementing operating plans and calculating power benefits, but the Entities have found it necessary to create several agreements on detailed principles and procedures. The first was signed in 1967 and has been updated many times, the last of which was in November 2003. Many of the procedures are the result of negotiations between the Entities and/or Permanent Engineering Board opinions that resolved issues and disputes.

The operating criteria in Assured Operating Plans for Canadian and coordinated U.S. reservoirs are mainly a series of rule curves (Figure 8) that guide reservoir operation for flood control, optimum power generation, and reservoir refill. Typically, Operating Rule Curves guide reservoir operations, except when inflows are not sufficient to meet planned firm energy capability the coordinated system drafts proportionally using the Critical Rule Curves to meet the firm energy capability. The Operating Rule Curves are a synthesis of the 1st Year Critical Rule Curve, Assured and Variable Refill Curves, lower limits, and Flood Control Rule Curves. Critical Rule Curves are based on critical period[12] planning studies of a coordinated reservoir operation that maximizes firm energy capability in the worst historic streamflow sequence. Assured and Variable Refill Curves vary as a function of historic or forecast inflows and are designed to assure a 95% confidence of refill while meeting firm energy capability. Firm energy is that which can be assumed to be available in all water conditions, and nonfirm energy is any additional energy. Also included are minimum and maximum flow limits and procedures for variable target flows and contents at Mica, and flow limits and storage upper limits for Arrow, that optimize Canadian power generation so that the total Canadian storage operation remains close to the controlling rule curve.

Figure 8: Assured Operating Plan rule curves

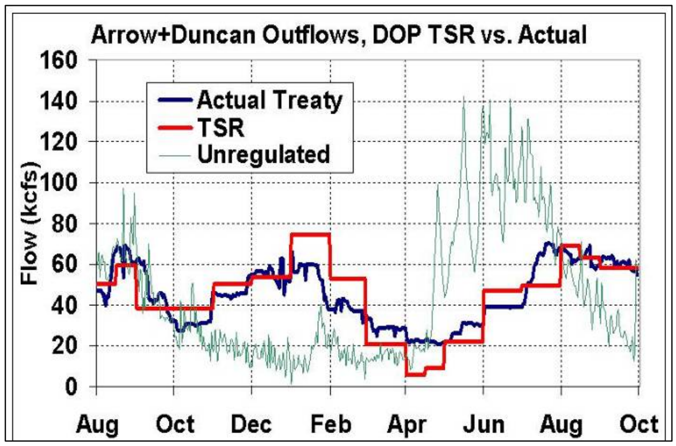


Each year a Detailed Operating Plan is prepared just prior to the beginning of the next operating year. The Detailed Operating Plan includes procedures for implementing the Assured Operating Plan and the Flood Control Operating Plan. If the Entities agree, the CRT allows the Detailed Operating Plan to include changes from the Assured and Flood Control Operating Plans that may produce results more advantageous to both countries. The Entities have assumed, and the Permanent Engineering Board has agreed, that this can include benefits other than power and flood control. Typically, the Entities only agree to minor changes in the Detailed Operating Plan document, and prefer to address additional benefits during the operating year. Therefore the Entities often agree during the operating year to mutually beneficial Supplemental Operating Agreements (SOA) that meet U.S. and Canadian power and/or fish and wildlife and/or recreation needs. There have been numerous SOAs, from a few in the 1970's to one or more every year since the 1990's.

Prior to 2000, the Detailed Operating Plan included information to coordinate the operation of Libby with downstream projects in Canada. In January 2000, the Entities agreed to a Libby Coordination Agreement that provides new procedures for coordinating the operation of Libby for power and flood control benefits in Canada. The agreement recognized the continued operation of Libby for nonpower constraints required by the Endangered Species Act, and created several procedures to mitigate adverse impacts in Canada (see section 13.9). These include the U.S. development of a Libby Operating Plan, a Canadian option for provisional draft of Arrow reservoir and corresponding exchanges of power between B.C. Hydro and BPA, storage exchanges between Libby and Canadian reservoirs, and excluding updated nonpower constraints at Libby from Assured Operating Plans for Canadian storage and Canadian Entitlement calculations. Each year, the U.S. Entity updates the Libby Operating Plan for current U.S. requirements in actual operations.

9. STORAGE OPERATIONS

Figure 9: Treaty Storage Regulation (TSR) study vs. Actual



Operation of Canadian storage is implemented through weekly agreements on the total of Arrow plus Duncan outflows. These outflows are based on the assumption of drafting or filling all three Canadian reservoirs to end-of-month storage levels determined by a Treaty Storage Regulation (TSR) study plus any Supplemental Operating Agreements. The TSR study is a hydro-regulation model of the coordinated system based on Detailed Operating Plan operating criteria. This model is updated twice monthly with actual inflows for prior months and forecasted inflows, flood control curves, and refill curves for future months. Figure 9 compares the monthly TSR study results in a typical year with actual Canadian daily outflows resulting from Supplemental Operating Agreements and weekly flow agreements. In this example, large reductions in January and February outflows were used to augment flows later in the year for fishery benefits.

Although the TSR determines a power operation for each project, the CRT limits the Canadian obligation to a monthly reservoir balance relationship for the whole of Canadian storage. Canada is allowed the flexibility to operate individual projects for maximum Canadian benefits, so long as the flow at the border is the same as the agreed operating plans. During flood control events, however, the U.S. may direct the daily operation of each project to provide the required flood risk management.

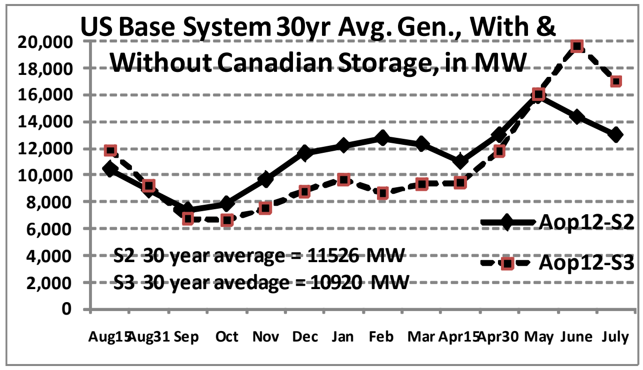
10. CALCULATION OF THE CANADIAN ENTITLEMENT

The Canadian Entitlement to the downstream U.S. power benefits is one-half of the estimated increase in U.S. dependable capacity and average annual usable energy due to Canadian storage regulation. The Entitlement calculations are based on the operation of a theoretical U.S. Pacific Northwest hydro-thermal[13] power system with operating criteria and/or procedures from the Assured Operating Plan. The system includes only the 24 Columbia Basin reservoirs and projects listed in the Treaty (Base System) and today's thermal installations and annual electrical load shape. The Base System is essentially the major projects that existed when the CRT was signed in 1961 plus projects under construction or planned on the main stem of the Columbia

River. Calculations are performed with and without CRT Canadian storage to determine the Base System capability using the 30-year streamflow record from August 1928 to July 1958 (Figure 10). Use of the Base System for calculating the Entitlement puts Canada in a "first added" position by not counting U.S. reservoirs added since 1961, most notably Libby and Dworshak.

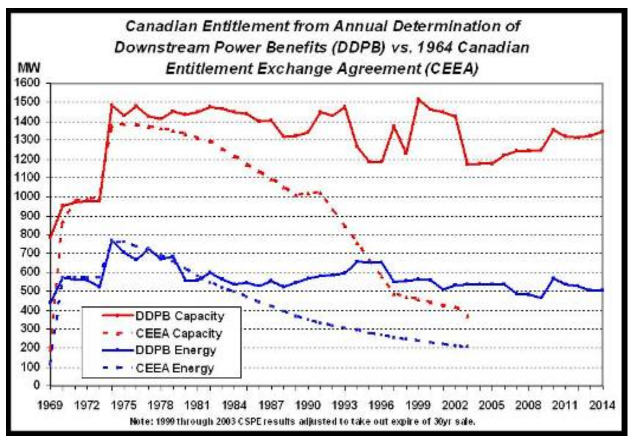
The Energy Entitlement is one-half of the increase in the 30-year average sum of firm hydro energy (from the critical streamflow period), the nonfirm hydro energy that can be used to displace thermal installations that meet load in the Pacific Northwest Area (i.e., the thermal displacement market), and 40 percent of the remaining nonfirm energy. Past forecasts of the thermal displacement market have varied greatly from year to year due to changing economic and power system conditions, resulting in wide variations in the Energy Entitlement (Figure 11). The Capacity Entitlement is one-half of the increase in average critical period energy for the U.S. Base System with and without Canadian storage, divided by the average critical period monthly load factor.[14] Because of different critical period lengths between the Base System with and without Canadian storage, which is driven largely by changes to operating criteria and thermal resources, the calculation produces a variable and unstable result that has little relation to actual capacity benefits.

Figure 10: U.S. Base System generation with and without Treaty storage operation



Once calculated and agreed to by the Entities five years in advance, the Canadian Entitlement cannot be changed and must be delivered regardless of the actual incremental power benefits. Actual benefits may be substantially different from agreed benefits, due to actual precipitation, reservoir and river operating constraints, power loads and markets, and generator and transmission reduced capability or outages. The most significant factors affecting the Entitlement are: the forecasts for Pacific Northwest Area firm load (energy and peak), thermal installations and the thermal displacement market for nonfirm hydro energy; flood control and other hydro operating constraints; and irrigation depletions. As the thermal displacement market increases in the future, more of the Base System nonfirm hydro energy will become usable, making the operation of CRT storage, which converts hydro nonfirm energy to firm energy, less valuable and decreasing the Canadian Energy Entitlement.

Figure 11: Comparison of 1964 estimate of Capacity and Energy Entitlement with the actual calculated values.



11. DELIVERY OF CANADIAN ENTITLEMENT

Concurrent with CRT ratification in 1964, British Columbia sold its right to the Canadian Entitlement for a 30-year period beginning after the planned completion date of each Canadian project. The buyer was Columbia Storage Power Exchange (CSPE), a consortium of Pacific Northwest utilities owned half by four private utilities and half by 37 public utilities. British Columbia received U.S. $253.93 million from that sale, which, along with the flood control payment, was expected to be sufficient to construct the three dams required by the CRT plus a portion of the Mica powerhouse.

To decrease the risk of a variable Entitlement and obtain a lower bond interest rate, CSPE exchanged the Entitlement power with BPA for a fixed amount of power for 30 years. CSPE participants sold the power to California utilities on a recallable basis from 1968 to 1983. This sale provided one of the major benefits that justified construction of the Pacific Northwest-Pacific Southwest transmission intertie. Because load growth and thermal generation in the Pacific Northwest area has been much less than forecast in 1963, the Canadian Entitlement has not decreased as much as originally expected. Thus, the purchase by CSPE and exchange with BPA provided more benefits than expected for BPA and the owners of the Mid-Columbia non-Federal dams. Figure 11 compares the estimated Canadian Entitlement for the 1964 sale to the actual values calculated annually.

Beginning in April 1998, and ramping up to the full amount in April 2003, the CSPE agreements expired and ownership of the Canadian Entitlement reverted to Canada. The U.S. government is now obligated to deliver the Entitlement power to the Canadian border as scheduled by the Canadian Entity each work day for the following day or days according to an industry-generated calendar. The Canadian Entity may take deliver on any hour, at any rate up to a maximum of the Capacity Entitlement, and limited to the total Energy Entitlement for each month. A March 1999 Entity Agreement defined transmission losses and scheduling guidelines for power delivery to Canada. The guidelines use existing transmission interconnections at Blaine, Washington, and Nelway, B.C., instead of the CRT-defined point at Oliver, B.C. A separate March 1999 Entity Agreement and exchange of Diplomatic Notes allows British Columbia the option of disposing of (selling) the Canadian Entitlement directly in the U.S. This option would reduce transmission losses compared to delivery in British Columbia, but the transmission costs would be assigned to British Columbia instead of the U.S.

Figure 12: Duncan Dam, courtesy of B.C. Hydro

British Columbia uses the Canadian Entitlement either to meet load in the province or to sell to U.S. markets, where currently it is worth roughly $220 to $350 million per year (assuming $50 to $80 per MWh for 500 average annual MW delivered on heavy load hours at rates up to 1200 MW).

Entitlement Allocation Agreements signed in 1964 between the U.S. Entity, BPA, and the public utility districts owning the five Mid-Columbia non-Federal dams required the public utilities to deliver to BPA the portion of the Canadian Entitlement generated at their projects. The Entitlement calculation assumes a coordinated optimum power operation of both Canadian and related U.S. projects. To ensure the coordination of U.S. projects, the U.S. Entity, BPA, the Army Corps of Engineers, and fourteen U.S. utilities owning affected hydro projects created the 1964 Pacific Northwest Coordination Agreement. The Coordination Agreement requires coordinated planning and operation of U.S. and CRT reservoirs and rights to exchanges of power between utilities that ensure the ability to realize downstream power benefits from Canadian and U.S. projects. The agreement requires the U.S. Entity to use Coordination Agreement procedures for CRT operating plans to the extent allowed by the CRT. The Coordination Agreement and the Allocation Agreements were updated in 1997 and extended until 2024. The new Allocation Agreements allow delivery of the Entitlement obligation from each mid-Columbia dam to BPA on a fixed schedule. The power delivery is shaped flat on heavy load hours instead of varying as a portion of Entitlement power scheduled by Canada. To minimize uncertainty, the obligation is defined as 27.5 percent of a calculated estimate of the Entitlement as a function of Assured Operating Plan loads instead of the actual Entitlement.

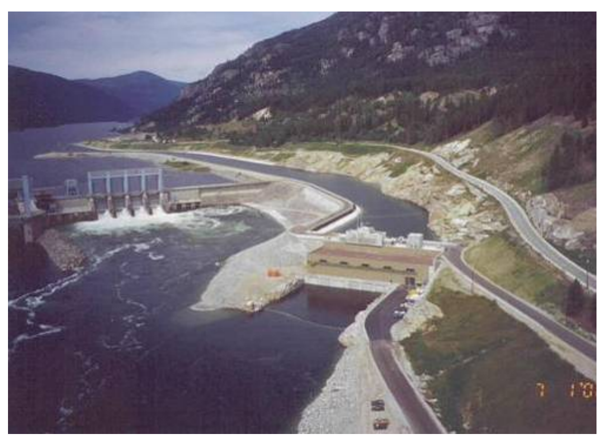
12. DIVERSIONS

During the life of the CRT, both Canada and the U.S. are prohibited from diverting any water that would alter the flow across the border, with two exceptions. The first is any consumptive use, which includes domestic, irrigation, and industrial uses. The second is a series of rights to divert the Kootenay River upstream of Libby into Columbia Lake, the source of the Columbia River. Since September 1984, Canada has had the right to divert 1.5 Maf annually. This diversion would result in about a 40 MW energy loss at Libby and about a 90 MW net energy gain for B.C. Hydro's Kootenay+Columbia projects. Between 2024 and 2044, Canada has an additional right to divert all Kootenay River flows exceeding a Canada/U.S. border minimum flow of 2.5 kcfs and between 2044 and 2064, all flows exceeding a border minimum of 1 kcfs. Both of the latter diversion rights would severely reduce Libby generation. It is likely, however, that potential environmental impacts and less-expensive alternatives will preclude any action on these options in the foreseeable future.

13. CONFLICTS, OPPORTUNITIES, AND AGREEMENTS

During the life of the CRT there has been little public awareness in the U.S. of the CRT, its benefits, or issues. The same is not true in British Columbia, where the basin residents are aware of the CRT and have actively raised Treaty related issues. The initial implementation of the CRT brought substantial controversy in Canada. Whole communities and farms were uprooted to make way for the reservoirs, and many people believed they were not fairly compensated for their loss. There was also criticism in Canada and the U.S. on the overall benefits of the CRT. A detailed economic analysis published in 1967 by Dr. John Krutilla concluded there were better alternatives for both Canada and the U.S.[15]

Figure 13: Keenleyside Dam, courtesy of B.C. Hydro



During the early 1970s, inflation and other economic problems in Canada substantially raised the cost of completing the CRT dams.[16] When the British Columbia government changed parties in 1972, there was widespread public criticism of the higher costs. During the 1980s, the annual Canadian Entitlement calculation began to deviate from the amount assumed for the 1964 sale to the U.S. The calculated amount has continued to stay much higher than the original forecast, with some viewing that as evidence the 30-year Entitlement sale was a bad deal for

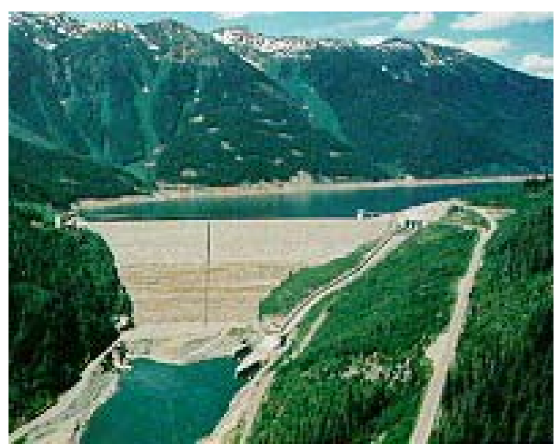
British Columbia. However, a February 1988 Analysis of the Sale of the Columbia River Downstream Benefits by B.C. Hydro[17] concluded that selling the downstream benefits was a sound economic decision for British Columbia even with the benefit of hindsight analysis. Since the Entitlement sale expired in 2003, British Columbia is now the beneficiary of a much larger Canadian Entitlement than was expected in 1964. Given that actual U.S. power benefits have decreased due to operation of U.S. projects for fishery objectives instead of the optimum power operation assumed in the Assured Operating Plan, the situation is reversed, with British Columbia appearing to get the better deal.

In 1995, the British Columbia government created the Columbia Basin Trust to help the people in the Columbia region most affected by the CRT by directly sharing some of the financial benefits from the dams. Since then, the Trust has been successful in addressing many of the public concerns about the CRT. But there are still issues in Canada with fish and wildlife impacts and a desire for stakeholder involvement in managing the Treaty future. Beginning in 2000, B.C. Hydro has conducted several public processes for water use planning that has resulted in some changes to operating policy for Canadian projects.

In the U.S, it is mainly the members of the Pacific Northwest Coordination Agreement, the Canadian Entitlement Allocation Agreement, the Northwest Power Pool, the Northwest Power and Conservation Council, and fishery agencies and tribes that are interested in Treaty activities. In general, the fishery interests want higher spring-summer flows, and the power interests want a reduced Canadian Entitlement and operation of Canadian storage for optimum power generation. Since there is no flexibility to modify Assured Operating Plans for objectives that decrease power and flood control benefits, the U.S. Entity has attempted to improve fish and power benefits through changes to Detailed Operating Plans and Supplemental Operating Agreements.

The Entities have always enjoyed and worked hard to retain constructive work relationships, which have enhanced their ability to create additional power, flood control, and other benefits. Both Entities have focused on a win-win approach, with shared technical analysis, development of creative alternatives, and avoidance of legal disputes. The Permanent Engineering Board, which meets annually with the Entities, has been helpful in resolving issues and in making recommendations to the governments of British Columbia, Canada, and the U.S. Departments of State, Army, and Energy.

Figure 14: Mica Dam, courtesy of B.C. Hydro



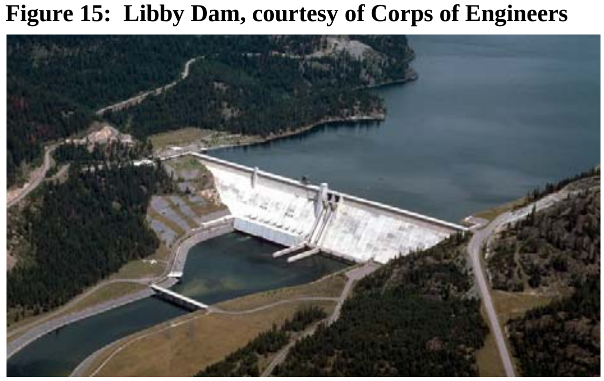
There have been numerous difficult issues and several significant disputes since 1964. Only a few rose to the level requiring involvement of the Permanent Engineering Board or the U.S. State Department and Canadian Ministry of Foreign Affairs and Trade. Almost all issues can be placed into three categories: 1) Non-Treaty storage, 2) operation of Canadian and U.S. projects for fish and wildlife objectives and the resulting power and other impacts, and 3) methods for calculating the amount and procedures for delivery of the Canadian Entitlement. The most notable are the following.

13.1 Non-Treaty Storage: As described in Section 4, British Columbia built Mica dam with an additional 5 Maf of non-Treaty storage. The CRT limits the use of any non-Treaty storage constructed in Canada after 1964 so as not to decrease the U.S. benefits from CRT operating plans. During the construction of Mica Dam, the Entities created several initial filling agreements that ensured that Mica's non-CRT storage occurred at times that did not reduce the CRT operating plan power benefits. Following initial fill, the Canadian Entity used the flexibility created by that non-Treaty storage to optimize power benefits by shifting storage operations between Mica, Arrow, and Duncan so long as the flow at the border was the same. The U.S. Entity wanted a portion of that operating flexibility to allow changes to cross border flows and sharing of the downstream power benefits. But only minor short-term agreements were tried in the 1970s.

In 1982, the Canadian Entity thought the limit on operation of non-Treaty storage did not apply to the initial filling of Revelstoke reservoir. They proposed to fill the project's 4.4 Maf without compensating the U.S. for the resulting downstream power losses. The U.S. objected, and negotiations led to a 10-year non-Treaty storage agreement (NTSA) between B.C. Hydro and BPA, signed in 1984. The NTSA shared power losses from the initial fill of Revelstoke and Seven-Mile dams, and shared the operational use and resulting downstream power benefits from 2 Maf of non-Treaty storage. A companion agreement between BPA and the owners of the Mid-Columbia projects mitigated adverse impacts. The NTSA agreement was renegotiated in 1990 to include up to 4.5 Maf of non-Treaty storage at Mica. The companion agreement with the Mid-Columbia project owners was also renegotiated to share the BPA benefits. The NTSA was extended until 2003, and later extended again until it expired in June 2004. However, because the NTSA storage accounts were not full in 2004, the refill provisions of the NTSA survive, and the storage accounts (currently ~88% full) must be refilled by June 2011.

Because use of non-Treaty storage could be restricted by either BPA or B.C. Hydro for power or nonpower limitations, the ability of both to make effective use of non-Treaty storage for power benefits was reduced by U.S. Biological Opinions for Endangered Species requirements. This has significantly reduced the incentive for B.C. Hydro to negotiate a new agreement. The situation may change when non-Treaty storage refills and reduces Canadian operating flexibility, but any future NTSA is likely to be more limited than the 1990 Agreement.

Figure 15: Libby Dam, courtesy of Corps of Engineers



13.2 Capacity Credit Limitation: A 1981 question on the method to calculate the maximum limit for the Capacity Entitlement led to a long and sometimes difficult dispute with a potentially large impact on the amount of capacity owed to Canada. In 1982, the U.S. Entity hired a team of retired U.S. CRT experts to define the method agreed to in the CRT Protocol, which had not been well documented in 1963-64. The method described by the experts was approved by U.S. and Canadian Entity staff but then rejected by the Permanent Engineering Board.

In the early 1990s, the U.S. Entity conducted numerous technical studies of peaking capability in the downstream power benefit calculations to determine if all of the U.S. Base System hydro energy could be shaped to meet load on all hours of each month. Both Entities did extensive legal research and analysis of the CRT intent. The Canadian Entity accepted the Permanent Engineering Board position and found historical evidence to indicate that the Protocol agreement was based on an abbreviated method that used only the 1-hour peak capability. Although the U.S. Entity withdrew its proposal, the issue was never completely resolved.

The 2003 Principles and Procedures agreement documents the Canadian position on this issue but acknowledges that it assumes all hydro energy is usable to meet peak loads. Using those procedures, the Capacity Credit Limit is currently much greater than the Capacity Entitlement. But load growth and changes to procedures for determining reserves and peak capability may result in it having an effect in the future.

13.3 Water Budget, Irrigation Depletions, and Loads and Resources: In 1982, the Pacific Northwest Electric Power and Conservation Planning Council directed the U.S. federal agencies to provide a 3.45 Maf Water Budget of additional spring flows to aid salmon migration. The Council also asked the U.S. State Department if the CRT would allow for release of Canadian storage for Water Budget flows. The U.S. State Department thought the Entities could agree to operating plans with an appropriate release of water for fish flows, but the exchange of letters prompted the Permanent Engineering Board to make its own analysis. The Board concluded that nonpower operating objectives or constraints (e.g., for fish or recreation) that are inconsistent with an optimum power operation could not be included in the Assured Operating Plans, but could, if the Entities agreed, be included in the Detailed Operating Plans.

In 1985, the Permanent Engineering Board advised the Entities that updated estimates of irrigation depletions used in the preparation of Assured Operating Plan studies must also be included in the downstream power benefit calculations. Such inclusion would cause an increase in the Canadian Entitlement and the U.S. Entity did not agree with the Board's advice. An extensive analysis of alternative ways to resolve the fish flow and irrigation issues discovered many new related issues. This included how shifting and shaping power loads for a more optimum power operation affected storage operating plans, resulting streamflows, and the effect of imports, exports, and extra-regional thermal generation on the downstream power benefit calculation.

The new issues were especially complicated due to three weaknesses in the Assured Operating Plan process. First, the CRT requirements for Canadian storage to operate for optimum power in Canada and the U.S., and for U.S. projects to make the most effective use of the improvement in streamflows for U.S. power, means that most modern nonpower constraints must be excluded, which causes the current Assured Operating Plan studies to have more power capability than the real hydropower system. This results in surplus firm energy which conflicts with the CRT requirement to use expected power loads and resources. Second, the CRT requires the Assured Operating Plan to include coordinated thermal installations, which the Entities had previously agreed includes extra-regional plants used by Pacific Northwest utilities. That assumption is inconsistent with the Entitlement calculation of usable nonfirm energy, which the CRT says must be based on displacing thermal resources in the PNW Area. Third, it is difficult to forecast six years in the future surplus firm energy sales, import/exports, and purchases of uncommitted thermal generation based on an unrealistic hydro capability and modern electric utility methods where portions of loads and resources are traded as commodities. The traditional forecasting approach, on which the CRT procedures are based, assumes each utility obtains firm resources or creates firm contracts to balance firm loads and resources.

Most of these issues were resolved in two 1988 Entity Agreements on Principles and Procedures. These agreements added dozens of new requirements for Assured Operating Plan studies, especially the use of updated irrigation depletions, balanced firm loads and resources, and extra-regional thermal resources in the load/resource calculation. The agreements limited Entitlement calculations to include only thermal resources needed to meet load in the Pacific Northwest, assumed net exports are supported by thermal generation, allowed seasonally shifted and shaped surplus firm exports, and allowed added resources and export loads that reflect the hydropower differences between the Assured Operating Plan and the real power system. This increased the ability to optimize power operations and increased spring-summer flows for salmon migration. Canada gained procedures that increased and stabilized the Energy Entitlement.

13.4 System Operation Review: In 1990, the U.S. Entity, together with other U.S. federal agencies, began an environmental analysis process that resulted in publication of the 1995 "Columbia River System Operation Review Environmental Impact Statement." This process was needed to renew the Canadian Entitlement Allocation Agreements and the Pacific Northwest Coordination Agreement, to deliver the Canadian Entitlement power to British Columbia, and to explore alternatives and select an operating policy for U.S. projects. The process to select a reservoir operating policy was superseded by the 1995 Biological Opinions for endangered species. Nevertheless, analyses conducted for the SOR-EIS have been used for many years by the U.S. Entity for discretionary operating decisions under the Detailed Operating Plan.

13.5 Entitlement Return: In 1993, the Entities began several years of discussions about the return of the Canadian Entitlement to Canada after expiration of the 30-year CSPE Sale (see Section 11) of the Duncan, Arrow, and Mica benefits in April 1998, April 1999, and April 2003, respectively. Due to U.S. concerns about the large rate of delivery, the Entities appointed negotiators that agreed in 1994 to principles for a potential U.S. purchase of a portion of the Capacity Entitlement (450 MW) for $180 million. When the market value of capacity dropped in 1995, the U.S. Entity cancelled the negotiations. The Entities' relationship reached a low point when the British Columbia government complained in the press about the failed negotiations and refused to allow the Canadian Entity to renew several operating agreements.

The other big issue was the point of delivery and transmission losses. The CRT requires delivery north of Grand Coulee dam near Oliver, B.C., unless otherwise agreed. But there was and is no transmission line at the border near Oliver. Instead, there is a large intertie south of Vancouver, near Blaine, Washington, and a smaller line north of Spokane, near Nelway, B.C. The U.S. wanted to reduce the amount delivered in recognition of the additional transmission losses and extra expense incurred to transmit the Entitlement power over the Cascade Mountains and then north to Vancouver. The Entities were unable to agree, although both wanted to minimize delivery costs. The U.S. Entity pressed the issue by publishing a Final Environmental Impact Statement and Record of Decision in March 1996 that stated the U.S. would deliver the Canadian Entitlement, beginning in 1998, to Oliver, BC.

The Entitlement delivery issues were resolved by a November 1996 Entity agreement that allowed Entitlement return over existing lines at Blaine and Nelway. This agreement also defined transmission energy losses at 3.4 percent (instead of the standard BPA transmission losses at that time of 1.9 percent) and established scheduling guidelines. The Entity agreement was updated in 1999, and together with a required exchange of Diplomatic Notes between the Federal governments, allowed options for delivery of the Entitlement in the U.S.

13.6 Storage Flexibility and Supplemental Operating Agreements: In 1993, the Canadian Entity ended a long-time practice that had allowed the U.S. Entity to vary Canadian storage operation above rule curves. This practice optimized U.S. power generation for current loads and non-hydro resources instead of the forecasted values in the Assured Operating Plan. The Canadian Entity thought the added value, above that shown in the Assured Operating Plan, should be shared and was concerned that occasional variations in reservoir levels had adverse environmental impacts. This initiated an on-going practice of developing annual Supplemental Operating Agreements that meet power and nonpower objectives in Canada and the U.S.

For 1993, the Entities agreed to a storage swap between Duncan and Libby to improve summer recreation in Canada and the U.S. on the Koocanusa reservoir. In the spring of 1994, the Entities agreed to the first Nonpower Uses Agreement. This Supplemental Operating Agreement stored 1 Maf in Canada in the winter for release in the spring and summer as flow augmentation. In the U.S., the flow augmentation improved downstream migration of juvenile salmon and helped to meet Vernita Bar minimum flows (Vernita Bar is the largest fall Chinook salmon spawning area on the mainstem of the Columbia River; minimum flow levels protect and preserve spawning and hatching there). In Canada, flow augmentation met Canadian trout spawning and dust storm avoidance objectives. The Entities have agreed to similar agreements every year since, except 1997 when it was not needed due to very high spring flows.

In 1996, the Entities agreed to a summer storage swap from Arrow to Libby, and since then there have been numerous Entity Agreements to swap storage draft between Libby and Canadian Treaty projects for recreation and/or power benefits. In addition, there have been numerous agreements for additional summer or fall storage for power and nonpower benefits.

13.7 Nonpower Constraints, Treaty Storage Obligation, and the Definition of the Critical Period: Beginning in 1995, the U.S. hydropower system operation was dramatically altered in an attempt to increase protection for salmon in accordance with the Endangered Species Act. The effect has been to reduce generation on the Federal Columbia River Power System by over 1,000 average annual MW,[18] roughly equivalent to the power generated at all four dams on the lower Snake River. Like the Water Budget, the 1995 Biological Opinion flow and spill objectives were not included in the Assured or Detailed Operating Plans. However, the Detailed Operating Plan included some operating criteria for which it was not clear if it was affected by fish and wildlife objectives. As a consequence, the Canadian Entity objected to continuing the then-existing procedure for coordinating draft of Canadian and U.S. reservoirs to meet firm energy capability. That procedure was based on Northwest Power Pool studies that included updated U.S. power loads and nonpower constraints. So the Entities agreed to a new procedure to determine monthly CRT storage obligations in actual operations which is based on semi-monthly updates to a Treaty Storage Regulation study which uses Assured Operating Plan loads and nonpower constraints.

By 1996, the Entities began to have increasing difficulty in deciding which nonpower constraints were consistent with an optimum power operation. In addition, the Entities disagreed on the procedure for defining the critical streamflow period, a key factor in determining operating criteria and calculating the downstream power benefits. The issue was whether or not nonpower constraints should be permitted to affect the determination of the start of the critical period.

Unable to agree on the CRT intent for the critical period, and seeing an opportunity to resolve both issues, the Entities agreed to a specific list of constraints (basically those used in the 1980 operating year) for U.S. Base System projects. The Entities agreed to use the constraints in all future Assured Operating Plan and Canadian Entitlement calculations. Because the agreed constraints did not affect the start of the critical period, that issue was moot.

13.8 Libby Coordination: The February 2000 Libby Coordination Agreement resolved a dispute that began in December 1994 when the Canadian Entity claimed that Libby's planned operation for sturgeon and salmon flows, and the resulting loss of downstream power benefits in Canada, was not consistent with the CRT. The U.S. thought the CRT reference to Libby operations for other purposes could include fishery objectives. Canada believed it was entitled to downstream power benefits resulting from Libby's operation only for power and flood control. The U.S. implemented the sturgeon/salmon operation and Canada requested compensation. The dispute continued for many years, with exchanges of diplomatic notes and legal analyses, and the Entities unable to agree on Assured Operating Plans.

Finally, in 1999, with no agreed Assured Operating plan for the 2000-01 operating year, the U.S. Entity requested and was given limited approval from the U.S. State Department to negotiate an agreement. Neither side relinquished their legal position. Instead, the Entities agreed to a mutually beneficial arrangement that recognized that the U.S. would continue to operate Libby for fish and wildlife requirements, and required BPA to exchange power with B.C. Hydro based on downstream federal power generation resulting from provisional draft of Arrow reservoir. The agreement also specified coordinated planning, allowed for exchanges of storage between Libby and Canadian projects for recreation and power benefits, limited Libby's nonpower constraints in Assured Operating Plans and Canadian Entitlement calculations, and required B.C. Hydro to deliver one average MW to BPA. The result was a neutral impact on U.S. net generation, with B.C. Hydro gaining the difference in market value of the exchanged power which was expected to be comparable to the average value of Canadian power losses due to Libby's operation for fish. An exchange of Diplomatic Notes between the two federal governments confirmed that the agreement did not affect the underlying legal positions.

13.9 Imports, Exports, and Thermal Installations: During 2001 to 2003, while preparing the 2006-07 through 2008-09 Assured Operating Plans, the Entities noticed increasing difficulty in forecasting imports, exports, and thermal generating resources. The difficulty arose because many utilities now rely on short-term purchases, and many thermal plants are owned by non-utilities without firm sales contracts. It became difficult to determine what thermal installations would be used to meet load in the Pacific Northwest Area. This assumption is one of the most important parameters in the calculation of the Energy Entitlement. The Entities agreed to a new procedure that established one large generic thermal plant, sized as needed to balance Assured Operating Plan loads and resources, and shaped seasonally similar to known planned Pacific Northwest Area thermal resources. In addition, imports and exports were added to shape net imports/exports similar to the loads the actual hydropower system would serve.

13.10 Flood Control Exchange: In 2001, the Canadian Entity requested an exchange of flood control draft requirements between Mica and Arrow, changing from a 2.08/5.1 Maf allocation (respectively) to a 4.08/3.6 Maf allocation. The U.S. Entity approved the exchange, agreeing that it provided equivalent flood control. The purpose of the flood control exchange was to increase flexibility at Arrow to store overdrafts from Mica without changing downstream flows. This would allow Arrow to operate at higher elevations and increase generation at the new powerhouse completed in 2002. In 2004, to take advantage of the increased flexibility, the Entities agreed to add Arrow Power Operating Criteria to the Assured Operating Plans that increase Canadian and U.S. power benefits. These specify January and February maximum flow limits and January to June maximum storage levels that apply only to the Treaty Storage Regulation studies.

13.11 VarQ: Beginning in 2003, the U.S. Army Corps of Engineers implemented a new Libby flood control procedure based on variable outflows, known as VarQ (variable flow). VarQ raised Libby's flood control curve in near median water conditions, which enabled increased spring and summer outflows from Libby to improve flow conditions for resident and anadromous fish downstream. Because Libby's flood control draft does not change in high volume runoff years, and because of compensating changes to Grand Coulee flood control curves, the effect on system flood control is expected to be minimal. The Canadian Entity has objected to VarQ due to adverse power and potential flood control impacts in Canada and has requested compensation under the provisions of the Libby Coordination Agreement. The Entities are currently studying the impacts and potential solutions to this issue.

13.12 Wind Generation: Wind generation, conservation and other renewable resources decrease the need for thermal generated energy. The result is a smaller thermal displacement market for nonfirm hydro energy, which increases the Canadian Energy Entitlement. This is because a smaller market to make nonfirm energy usable means the operation of Treaty storage to change hydro nonfirm energy to firm energy is more valuable.

The expected wind generation energy in recent Assured Operating Plan studies has been based on past average monthly generation. As experience with wind performance grows, it may be appropriate to allocate between firm and nonfirm wind energy, which may reduce the Energy Entitlement. In addition, wind generation requires capacity reserves that reduce peak hydro capability available to meet load, which may reduce the Capacity Entitlement in the future. The U.S. Entity is studying potential changes to procedures.

14. 2014/2024 CRT REVIEW

The CRT has three provisions that are enabled only on or after September 16, 2024. First is the required change from a dedicated amount of storage for flood control to a Called Upon operation described in section 5. Second is an option for either government to terminate the CRT if at least 10-years prior notice has been given. Third is an option for Canada to start or increase diversions of the Kootenay River into the Columbia at Canal Flats, B.C. The diversion option appears to be very unlikely due to adverse environmental impacts. However, the flood control and termination provisions, and changing needs and desires for hydropower, fish, and other water uses, make the future of the CRT very uncertain. Given the enormous amount of benefits that could be affected, the stakes for decisions on the CRT future are very high.

If the CRT continues in its present form, the coordinated operation for power benefits in both countries and the Canadian Entitlement to downstream U.S. power benefits would continue. The Canadian Energy Entitlement is expected to decline slowly, mainly as a function of added thermal generating resources needed to meet load in the Pacific Northwest. Implementation of Called Upon flood control is expected to cause some changes to Canadian and U.S. reservoir operations, which could significantly affect other operating objectives, including fisheries and recreation. But in general, and absent any new agreements, the Canadian storage operations from future Assured and Detailed Operating Plans, Supplemental Operating Agreements, and reservoir balancing are likely to be similar to today's operations. However, the ongoing option for either country to terminate the CRT, and the need to agree on procedures to implement Called Upon flood control, will change the basis for negotiating post-2024 operating plans and related agreements. Therefore, it may be possible, within the limits of the existing CRT, for the

Entities to develop mutually beneficial agreements for after 2024 that create more or different benefits, or reallocate the benefits, than is feasible today.

With termination of the CRT, British Columbia may operate Mica, Arrow, and Duncan as it desires, except that provisions for Called Upon flood control storage continue, the Boundary Waters Treaty applies, and the provisions for Libby coordination and Kootenay River diversion options continue. Absent new agreements, Mica and Duncan reservoirs are likely to continue to operate for power and flood control generally similar to today's operation. Arrow's operation may be quite different with higher reservoir elevations and a more constant level of outflows, although Called Upon flood control may sometimes require significant draft of Arrow in the winter. B.C.'s Water Use Plans for all three projects would likely be updated to reflect the lack of CRT constraints, which could have a significant effect on storage operations. The U.S. would be relieved of the Entitlement obligation, but the expected changes in storage operations, and the uncertainty in that operation, are likely to cause the U.S. to compensate by acquiring additional generation or storage resources and operate U.S. projects differently. Nevertheless, the expected operation of Canadian storage for power, flood control, and other purposes would produce substantial U.S. power and flood control benefits.

While the Canadian and U.S. Entities are given broad discretion to implement the CRT, they are not authorized to modify or terminate the CRT. In the U.S., only the State Department and President can terminate or pursue Treaty modifications. In Canada, by prior agreement, termination would require agreement of both the Province of B.C. and the Canadian federal government. However, given the importance of the expected and potential 2024 changes, the Entities have begun a 2014/2024 Columbia River Treaty Review process to examine the CRT's 2024 provisions. Phase 1 of that process is joint technical studies to provide fundamental information on post-2024 conditions from the limited perspective of power and flood control. These initial studies are expected to help in the planning of future analyses, and are not designed to establish future alternatives, policies, or strategic direction. The Entities are closely coordinating with their respective governments on the Phase I studies.

It is worth noting that the governments of Canada and the U.S. could, if desired, agree to renegotiate the terms of CRT at any time. There are various federal, state, and tribal governments and public interest organizations that would like to see major changes to Columbia River streamflows, and some view the CRT as an obstacle to change. Power interests view the Canadian Entitlement payment as too large compared to the power benefits actually realized in the U.S. In particular, the operation of U.S. dams for fish and wildlife objectives, which are not included in the Assured Operating Plan or downstream power benefit calculations, has sometimes reduced the actual U.S. power benefit of CRT storage to less than the Entitlement payment. Others think substantial change to the CRT is not needed or, if it is, it can be done through operating agreements that do not require modifying the CRT. At this time, however, many observers expect that substantial renegotiation of the CRT would be exceedingly difficult, and perhaps impossible, due its complex nature, the existence of many diverse and conflicting interests, and the potential for involving other national and international issues.

The Entities expect to publish the Phase 1 study results in the summer of 2010. Except for flood control analysis, the next steps for more detailed studies encompassing the broader questions and impacts relating to the future of the CRT have not yet been planned.

15. CONCLUSIONS

Power and Flood Control Benefits: When the CRT was signed, the two countries expected "... that the greatest benefit to each country can be secured by cooperative measures for hydroelectric power generation and flood control, which will make possible other benefits as well."[19] For power and flood control, the CRT has exceeded its design objectives. Flood damages prevented have been larger than expected. The power benefits, including the direct increase in downstream generation, and the related benefits for new dams and added generators, coordination agreements, and transmission interties, have provided enormous power benefits to the Pacific Northwest and British Columbia. Although some critics claimed the CRT did not achieve optimum power and flood control net benefits, there is no doubt it has enabled the Entities to come close to that goal.

Operating Plans: The processes of developing a Flood Control Operating Plan and an annual Assured Operating Plan for the sixth succeeding operating year have been very successful. The principles and procedures are complex but consistent with the need to achieve a joint optimum power operation that is coordinated with other regional generation. The flexibility under the Detailed Operating Plans for the Entities to negotiate agreements that achieve other benefits has also worked well, although it is limited to a net benefit for both Entities compared to the Assured Operating Plan.

Canadian Entitlement: The expected value of the Canadian Entitlement for the 1964 30-year sale to the U.S. was determined by studies that averaged calculations from a high and a low load forecast. Actual load growth was much less than even the low load forecast, resulting in a large under-forecast of the future amount of Energy Entitlement. Today, the high uncertainty of future load growth, renewable resources, thermal resources, capacity procedures, and transmission and power markets, make any forecast of the future Canadian Entitlement highly uncertain.

For today's purposes, the Entitlement calculation established under the CRT is unnecessarily complex, and the procedures for "first added", "average annual usable energy", and "dependable capacity" do not account for the modern realities of non-Base System projects, fishery objectives, the market values of power, and the option to terminate the CRT. The unique procedures produce a variable and unstable calculation for the Capacity Entitlement, and the adherence to a 1961 Base System operated only for power and flood control requires forecasting data and procedures for an imaginary world. An adjustment to bring the Canadian Entitlement closer to actual incremental value appears highly desirable.

Other Impacts and Benefits: Like most resource decisions, there were adverse impacts (some unintended) and opportunity costs due to the CRT. The CRT was designed for flood control and power, with the objective of smoothing out Columbia River flows within the year and over several years. By its very nature, then, the CRT has altered the pattern of annual water flow in the Columbia River and affected a vast and complex ecosystem from the headwaters to the ocean. Therefore, many associate the CRT with adverse effects on fish and wildlife, especially the reduction in non-hatchery anadromous fish on the lower Columbia River due to the reduction in flows that aid spawning and downstream migration. Others lament the loss of land submerged by the reservoirs and impact on some resident fish and wildlife.

These adverse impacts have been mitigated to some extent. On the Canadian side, the Provincial government has funded the creation of the Columbia Basin Trust with a portion of the Canadian Entitlement benefits, and created Water Use Plans that include operating procedures for fish and wildlife needs. In the U.S., the federal government has created massive programs to modify reservoir operations, add fish bypass facilities to powerhouses, and modify spillways and turbines in the Columbia River basin. Habitat improvements and hatchery reforms are also important components of the work to restore fish and wildlife. The costs to BPA for fish and wildlife mitigation measures relating to the impacts of the Pacific Northwest federal hydropower system now exceed $750 million per year,[20] accounting for about 30 percent of BPA's total costs. Since the early 1990's, the Entities have negotiated annual Supplemental Operating Agreements to improve streamflows and reservoir elevations for fish and recreation benefits. While these benefits are substantial, some would argue they don't go far enough.

Governance: Appointing the representatives of the agencies most closely related to power and flood control benefits to implement the CRT has proved very successful from the standpoint of the Treaty's original intent. The CRT was designed with broad principles and only general procedures that left much work to the Entities to figure out appropriate procedures. The CRT is enormously complex and so are many of the related agreements, including those for Pacific Northwest Coordination, Canadian Entitlement Allocation, and non-Treaty Storage. Therefore, there is a need for extensive training of staff for a wide variety of planning and operations knowledge and skills. Many of the Entity and Permanent Engineering Board members and staff have long-term experience with the CRT.

Under the Entities' direction, and PEB oversight, the CRT has proved durable and has evolved through numerous technical issues and changing societal values. The Entities have been able to provide additional benefits in both countries through negotiations based on mutually beneficial arrangements. However, given the narrow focus of the CRT on power and flood control, it is fair to say some interests are not confident that their objectives have been fully considered in CRT planning and operations.

There are many Entity agreements over the CRT's 45-year history that have approved operating plans, clarified CRT requirements, defined new procedures, and resolved issues and disputes. This has created a body of knowledge, experience, and procedures that have significantly added to the process of how the CRT is implemented today. Many of these agreements were relatively easy to negotiate due to technical expertise and clear objectives. Some agreements were reached only after long and difficult negotiations. In some cases, the Entities agreed to disagree, and looked for ways to work around the issue. The Permanent Engineering Board has been helpful through their annual review and their role to assist in resolving disputes. Taking disputes to a higher level, either the Canadian Department of Foreign Affairs and Trade or the U.S. State Department, has rarely been necessary. In general, most negotiations have been successful, with much good will, trust, and shared objectives among Canadian and U.S. Entity management and staff. This has enabled the Entities to address almost all issues through shared technical analysis, creative development of alternatives, a win-win approach to solutions, avoidance of legal involvement, and a commitment to make it work well.

Future: The Entities' long experience with implementing the Treaty has taught that all new issues have important links to the past, that many old issues were never fully resolved, and that historical principles, procedures, issues, and negotiation methods are helpful for predicting and resolving new issues. Nevertheless, the post-2024 option to terminate the Treaty and required changes to flood control obligations are substantially different than any issues faced since the CRT was originally negotiated. Either could result in significant changes to reservoir operations and benefits in both countries. Prior to 2024, the Entities can be expected to continue to address

Assured Operating Plan related issues and the request for VarQ compensation, and to seek additional fishery and other benefits through mutually beneficial changes to Detailed Operating Plans and Supplemental Operating Agreements.

The 2014/2024 CRT Review is the U.S. Entity's process to understand the challenges, opportunities, and benefits/costs of the post-2024 CRT provisions. The Phase I Studies are only the first step in that process. Changes to operating procedures needed to implement Called Upon flood control are not well understood, and further analysis of future flood control needs, Called Upon flood control operating procedures, and related impacts will be a major portion of investigating scenarios for the CRT future. Many agencies and other stakeholders are interested in rebalancing the CRT benefits, especially future needs for resident and anadromous fish, irrigation, recreation, as well as power and flood control. The potential effects of climate change will also be a major concern. All of these issues should be addressed, to some degree, whether or not the CRT is terminated.

The high degree of complexity of these issues, the conflicting objectives, the possibility of other Canada-U.S. issues affecting the negotiations, and the difficulty in modifying or creating new treaties make any major change very difficult and risky. Terminating the Treaty is likely to greatly increase the difficulties and risks of creating new agreements. On the other hand, a decision to continue the CRT must necessarily be better for both countries than termination, otherwise it should be expected that one country will terminate. The full extent of both alternatives should be explored.

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Endnotes:

[1] "Treaty between Canada and the U.S.A. relating to Cooperative Development of the Water Resources of the Columbia River Basin," January 17, 1961.

[2] Pre-1961 Columbia basin reservoir storage upstream of Bonneville Dam was approximately 18 Maf. The Treaty added 20.48 Maf, and BC Hydro added 5 Maf of non-Treaty storage at Mica and about 1 Maf at Revelstoke.

[3] The Dalles, Oregon, has the longest, and is believed to be the most accurate, record of Columbia River streamflows (daily since 1878 and annual peak from 1858 to 1878).

[4] From the 2000 Modified Streamflow report with daily flows from 1928 to 1999, modified to the 2000 level of depletions, and unregulated except for the upper Snake, upper Yakima, and upper Deschutes rivers.

[5] Northwest Power and Conservation Council.

[6] See Bibliography 2.

[7] The U.S. negotiators were the Under Secretary of Interior, the Deputy Asst. Secretary of State, and the Chief of the Army Corps of Engineers. Canada was represented by the Minister of Justice and members of the Ministry of Northern Affairs and Natural Resources, Ministry of External Affairs, and the B.C. Ministry of Lands and Forests.
[8] The March 8th Senate Hearing had no testimony against the Treaty. With strong support from regional Senators and utilities and the Depts. of Interior, Army, and State, the U.S. Senate gave 90 to 1 approval on March 14th.
[9] The name Koocanusa is a concatenation of the first three letters of Kootenai, Canada, and U.S.A.
[10] Columbia River Water Management Report, Water Year 1997.
[11] BPA is a federal agency responsible for marketing and transmitting the power from 31 federal hydropower dams (20.4 GW installed capacity) in the Pacific Northwest that are operated by the Army Corps of Engineers and Bureau of Reclamation, and one nuclear power plant. BPA owns and operates about 75% of the regional transmission grid and sells about one-third the regions electrical power.
[12] Critical period for energy sufficiency is the period beginning with the initial release of stored water from full reservoir conditions and ending with the reservoirs empty, when the water available from reservoir releases plus the natural streamflow is capable of producing the least amount of hydroelectric power in meeting system load requirements. The system generation during the critical period is the firm energy load carrying capability.
[13] Thermal installations include coal, nuclear, natural gas and other generation resources that need fuel.
[14] Load factor is the ratio of average to peak load.
[15] See Bibliography 14.
[16] Dr. Hugh Keenleyside said in 1974 the CRT was better for B.C. than any comparable alternative, even though the total cost of the Canadian projects (not including Mica powerhouse) when completed in 1973 was about C$69 million higher than the total U.S. payments received for power and flood control, plus interest (see Bibliography 20).
[17] See Bibliography 26.
[18] BPA 4H10c credit studies.
[19] Columbia River Treaty introduction.
[20] BPA 2010 Fact Sheet, http://www.efw.bpa.gov/IntegratedFWP/FACT_SHEET_Invests_fish_wildlifeFINAL.pdf

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