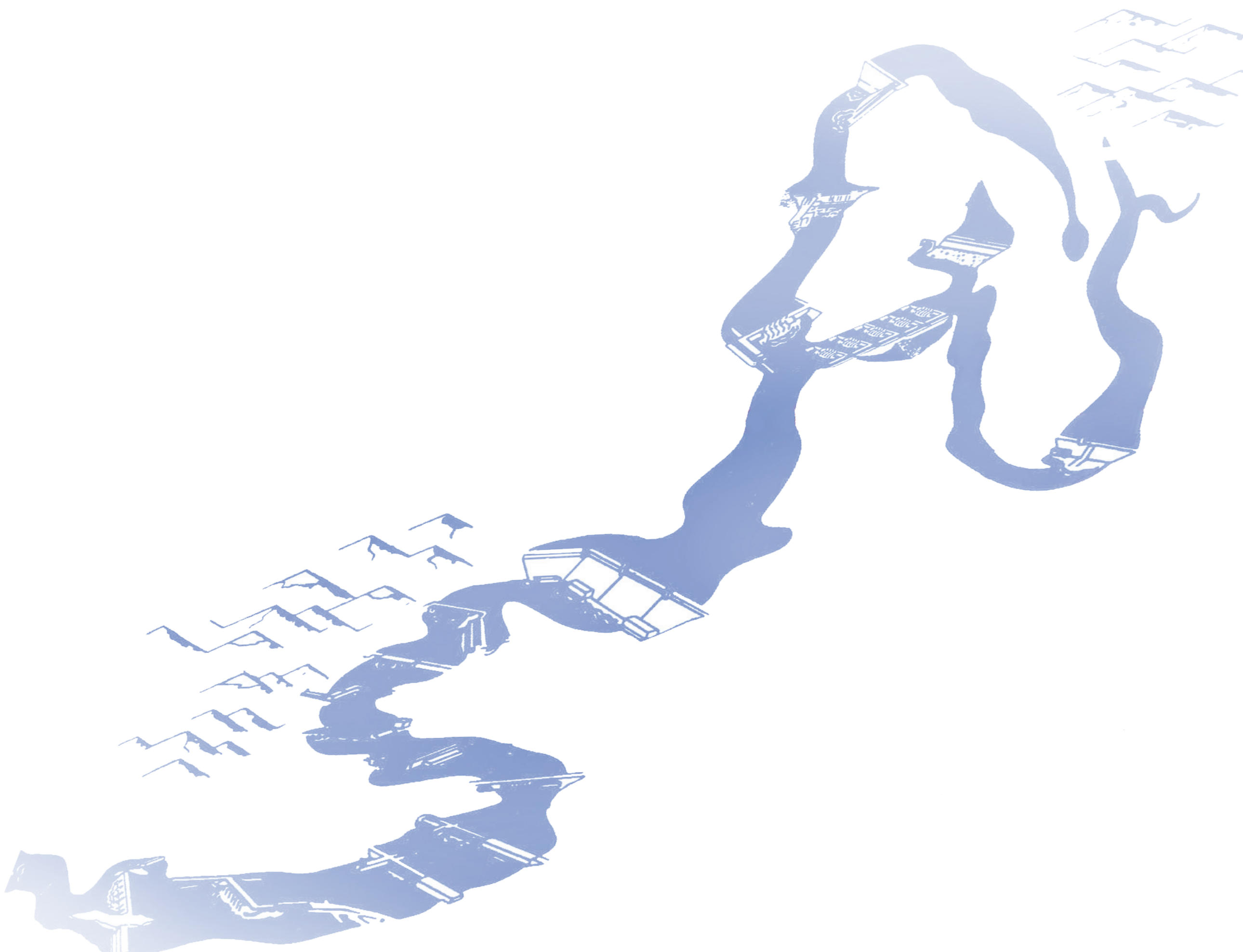
Columbia River Treaty

2014/2024 Review • Phase 1 Report

July 2010



Canadian and United States Entities

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Executive Summary

Columbia River Treaty
2014/2024 Review
Phase 1 Report

The Columbia River Treaty

Under the Columbia River Treaty (Treaty or CRT) of 1964, Canada and the United States (U.S.) jointly regulate and manage the Columbia River as it flows from British Columbia into the U.S. The Treaty has provided substantial flood control and power generation benefits to both nations.

The Treaty established Canadian and U.S. Entities as implementing agents for each government. British Columbia Hydro and Power Authority (BC Hydro) was designated as the Canadian Entity. The Bonneville Power Administration (BPA) Administrator and the U.S. Army Corps of Engineers (Corps) Division Engineer, Northwestern Division, were designated as the U.S. Entity.

The Canadian and U.S. Entities are empowered by their respective governments with broad discretion to implement the existing Columbia River Treaty. They are not, however, authorized to terminate, renegotiate, or otherwise modify the Treaty. In the U.S., authority over international treaties rests with the President, assisted in foreign relations and international negotiations by the Department of State and subject in certain cases to the advice and consent of the U.S. Senate. In Canada, international treaties are within the prerogative of the executive branch of the federal government. Under current policy, treaties are tabled in the House of Commons, and are subject to a waiting period before the executive branch brings the treaty into effect. In the case of the Columbia River Treaty, Canada has assigned certain rights and obligations relating to the Treaty to British Columbia pursuant to the Canada-B.C. Agreement. The Phase 1 report is provided to those respective governmental bodies to support possible independent and/or joint decisions that may be made with respect to the future of the Treaty.

The Treaty contains two important provisions that take effect on and after September 16, 2024, that could impact the current power and flood control benefits:

1. Canadian flood control obligations automatically change from a pre-determined annual operation to a “Called Upon” operation.
2. The year 2024 is the earliest date that either Canada or the U.S. can terminate most of the provisions of the Treaty, with a minimum 10-years advance written notice.

Hence, September 16, 2014, is the latest date that either nation could provide notice of intent to terminate and still have the termination effective at its earliest possible date in 2024. While termination would end most Treaty obligations, Called Upon flood control and Libby coordination provisions will continue regardless of termination. However, it is important to note that the Treaty has no end date and absent either country using the termination option will continue indefinitely.

Given the significance of the provisions that will take effect in 2024, it is important that the Canadian and U.S. Entities work toward an understanding of the implications for post-2024 Treaty planning and Columbia River operations. The joint effort by the Entities to conduct initial post-2024 modeling and analysis is referred to as Phase 1 of the 2014/2024 Columbia River Treaty Review.

Phase 1 Study Overview

This Phase 1 report of the 2014/2024 Columbia River Treaty Review describes the results of the three Phase 1 studies. The purpose of the Phase 1 studies was to provide information about post-2024 conditions both with and without the current Treaty from the perspective of the two purposes of the Treaty, power and flood control. The three studies were:

Treaty Continues: The Treaty was assumed to continue post-2024 with its current provisions. Canadian flood control obligations would change from the current prescribed annual operation of a dedicated amount of storage to an assumed Called Upon operation. Assured Operating Plans (AOPs) for power benefits and Canadian Entitlement provisions would continue, but modifications to current procedures would be required to reflect the revised Canadian flood control obligations.

Treaty is Terminated: The Treaty was assumed to be terminated in 2024 with no replacement agreement. The U.S. payment of the Canadian Entitlement would end, as would the requirement for Canada to regulate flows for U.S. power interests. Canadian flood control obligations would change to an assumed Called Upon operation. Absent the Treaty obligation to coordinate for power, Canada might operate its projects for Canadian power, flood control, and other benefits. Two Canadian operational scenarios were developed to depict a range of possible flows across the border into the U.S. One scenario represented a Canadian operation with minimal Canadian reservoir storage draft, for local flood control only, and one scenario represented a Canadian reservoir draft for power production in Canada.

Continuation of Pre-2024 Conditions: The Treaty was assumed to continue post-2024 with the pre-2024 Flood Control Operating Plan (FCOP), AOPs, and Canadian Entitlement procedures. The initial long-term purchase of prescribed annual flood control operation by the Canadian projects constructed under the Treaty is set to expire in 2024 independent of potential Treaty termination. This study is not consistent with the existing Treaty language in that it assumed the current coordinated FCOP operation would continue post-2024. Therefore, new arrangements (e.g., an extension or replacement of the current flood control purchase) would be required to implement these study conditions. This study was conducted to provide a basis for comparison with current operations.

The three Phase 1 studies included 13 scenarios. The scenarios were designed to test and compare a range of possible situations with varying: 1) study time horizons, 2) maximum flood control flow objectives, 3) AOP procedures, and 4) observed and forecast mode water supply and inflow model simulations.

Expected outcomes of the studies were to identify, discuss, and evaluate the impacts of these alternative post-2024 scenarios on:

- Canadian and U.S. power operations

- Future Canadian Entitlement levels
- Potential Called Upon flood control operations
- Potential outflows across the border from Arrow and Duncan
- Elevations and storage contents at Canadian and U.S. reservoirs

Findings and Conclusions

In general, the Phase 1 studies showed that power and flood control operations have common interests and requirements, regardless of whether or not the Treaty is terminated. Both operations attempted to reshape the flow of the Columbia River from peaks in the spring into the winter. Beyond that, there were basic similarities and trade-offs between those two purposes under both the Treaty Continues and Treaty is Terminated studies:

If the Treaty remains in place after 2024…

- U.S. flood control and power benefited from an assured operating plan for Canadian storage.
- Canada benefited from continued Canadian Entitlement and increased flexibility to optimize generation in Canada.
- Although there is uncertainty with the estimate, Canadian Entitlement energy levels were expected to decrease from about 470 aMW in 2024 to a minimum level of about 290 aMW by around 2040. The amount of future thermal resources used to meet load in the PNWA was the most important factor affecting the Canadian Entitlement[1]. The latter generally decreases with increases in thermal resources.
- Compared to the Treaty is Terminated scenario, coordinated U.S./Canadian assured power drafts provided substantial flood control benefits to the U.S., including more certainty and less volume of Canadian storage required during a Called Upon flood control request.
- The coordinated and assured operation provided substantial power benefits to the U.S. by shaping flows from Arrow from low power value months during the spring freshet to high-value winter/summer months, providing approximately 225 aMW of additional firm energy during the critical period compared with Treaty is Terminated, and maintaining a four-year critical period. [2]

If the Treaty terminates after 2024…

[1] Estimated energy conservation is one example of how Conservation assumptions can introduce uncertainty into the Entitlement calculation. The Phase 1 Entitlement calculation used conservation values from the NW Power and Conservation Council's 5th Power Plan, whereas the Council's 6th Power Plan included considerably more energy conservation. Higher conservation values result in a slower decline in Canadian Entitlement over time.

[2] Critical period is the historical streamflow period over which 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.

- Canada lost the Canadian Entitlement but gained flexibility to operate solely for Canadian power and non-power interests, with the exception of during a Called Upon operation.
- Canada was motivated to operate with Arrow elevations higher and on average more constant discharges across the year for more optimal power generation.
- Due to its proximity to the U.S./Canadian border, Arrow storage is more effective in providing U.S. flood control protection than either Mica or Duncan. Therefore, most of the Called Upon flood control draft was at Arrow.
- The Phase 1 power studies were limited to monthly time steps. However, average monthly flows do not represent the variability of discharges that may occur in actual operations. Uncertainty in daily/weekly/monthly flow releases could increase as Canada operated for its own needs and the operation was not coordinated.
- The reduction of Arrow plus Duncan outflows in August caused Grand Coulee to draft during the month and not fully refill during the fall and early winter in most years. In comparison, under the Treaty Continues scenario, the coordinated operation maintained flows from Arrow during this period and allowed a higher elevation at Grand Coulee.
- Overall average annual hydro energy production in Canada and the U.S. did not change much; however, the month-to-month shape of generation differed dramatically from the coordinated operation under the Treaty Continues scenario.
- The critical period was shortened from four years to one year and may be a concern during prolonged dry sequences.

Regardless of whether the Treaty is terminated or continues after 2024, system flood control operations are expected to change significantly, from an annual specified operation, to an operation as provided under Called Upon provisions. In either case, the U.S. will have access to flood control storage in Canadian reservoirs within the rights and limitations for Called Upon storage defined by the Treaty. Canada will be compensated by the U.S. for any operating costs incurred by Canada and economic losses arising directly from Canada forgoing alternative uses of the storage used to provide the flood control in the U.S. The Treaty provides the basic outline for Called Upon flood control but contains little detail with respect to procedures and methodologies for actual implementation. Those details remain to be resolved.

There are different views between the Entities with regard to interpretation of Called Upon rights and obligations and flood control objectives. Thus, two different flow objectives were simulated to provide information regarding a potential range of future operations. According to the FCOP, flooding begins around 450 kcfs as measured at The Dalles, Oregon, while major damages begin around 600 kcfs in the lower Columbia. Scenarios with maximum flood control objectives of 600 kcfs and 450 kcfs were conducted for both the Treaty Continues and Treaty is Terminated studies.

The Phase 1 studies are a starting point to understand Called Upon by examining one set of assumed procedures and methodologies. On the basis of those assumptions, some findings specific to Called Upon flood control include:

- The frequency that Called Upon flood control operations would be required was driven by the assumed procedure and maximum flood control target flow measured at The Dalles. As expected, the lower the target the more frequently Called Upon storage in Canada was needed. In scenarios where the target was 600 kcfs at The Dalles, Called Upon was needed in 21 years out of the 70-year record, and where the target at The Dalles was 450 kcfs, Called Upon was needed in 52 years of the 70-year record. This result was the same whether the Treaty continued or was terminated. The joint study team believes these results overestimate the frequency of Called Upon years, but further investigation was deferred to follow-up studies.
- The average volume of Called Upon storage required to meet U.S. flood control needs (additional storage over and above planned Canadian power and local flood control drafts) increased substantially when comparing the Treaty Continues and Treaty is Terminated studies, ranging from an average of 1 Maf to 11 Maf, respectively. The relative certainty of Canadian operations in the Treaty Continues versus Treaty is Terminated studies was the primary driver of Called Upon volumes as well as the duration of Called Upon events.
- The Treaty limits access to Called Upon storage only for flood events that cannot be adequately controlled by all related storage in the U.S. In the Phase 1 studies, effective use of flood control storage resulted in U.S. reservoirs being drawn down more frequently and deeper than current conditions, with reduced refill reliability. Comparing Called Upon years to non-Called Upon years, Hungry Horse, Dworshak and Brownlee reservoirs were drawn down an average of 45, 27 and 31 feet deeper, respectively, by April 30. Depending on the alternative flood control operation, Libby Reservoir in Called Upon years was drawn down an average of 11 to 47 feet deeper. At Grand Coulee, for Called Upon years in which refill began after May 1, the reservoir was drawn down an average of 14 to 18 feet deeper. In addition, Grand Coulee drafted empty four years out of the 70-year record in the base condition, compared to 30 years when the flow objective at The Dalles was 450 kcfs and 10 years when the flow objective was 600 kcfs.
- Most of the Called Upon draft from Canadian reservoirs is required from Arrow reservoir, since it is the most-effective Canadian reservoir for reducing flows at The Dalles. Because of the deep power draft at Mica, Called Upon did not usually affect Mica, and similarly, had only a minor impact at Duncan.
- Called Upon operation provided incidental power benefits to the U.S. while managing flooding in the U.S.

Possible Future Studies

The Phase 1 studies, while providing valuable information and knowledge, also generated many questions. Areas identified for possible further evaluation, either independently or jointly, include:

- **Called Upon Flood Control:** Regardless of a decision to continue or terminate the Treaty, the Canadian and U.S. Entities will be responsible for implementing Called Upon flood control operations after September 16, 2024, and there are many details to be resolved by the Entities. Assumed methods and procedures applied in the Phase 1 studies assisted in identifying some constraints and shortcomings. The Phase 1 report presents a series of recommendations for additional technical evaluations that should be undertaken to refine possible Called Upon flood control operations, including the associated economic losses and operating costs, and the use of all U.S.-related storage.

- **System Power Studies:** The Phase 1 studies did not examine optimizing the critical period and refill studies that determine operating criteria. Future studies could also explore methods to optimize firm load carrying capability and secondary energy production. In addition, other areas that were not considered or analyzed in detail in the Phase 1 studies were alternative scenarios for loads and resources, ability to meet peak loads, system reliability, the value of power, and the possible transition from an energy-deficit system to a capacity-deficit system.
- **Climate Change:** It is important when considering the future of the Columbia River Treaty or developing and assessing the implementation of Called Upon to consider the possible changes to the meteorology and hydrology of the Columbia Basin due to climate change. The scope of the Phase 1 studies did not include climate change scenarios; however, it is recognized that differing scenarios could be modeled in future studies.
- **Evaluation of Other Interests:** Analysis of the benefits and impacts associated with the Phase 1 studies described in this report was strictly limited to power generation and flood control. No attempt was made in this report to evaluate the future effects and benefits of the Phase 1 scenarios on other operating interests of the Columbia River system, such as fisheries, wildlife habitat, cultural resources, recreation, irrigation, water supply, water quality, and navigation. The Canadian and U.S. Entities recognize that evaluation of the potential impacts of system operations on other interests under alternative futures in which the Treaty is continued or terminated will be necessary in any future phases of study conducted under the Columbia River Treaty Review.

Either nation may choose to terminate most provisions of the Treaty as of 2024 with 10-year advance notice. At this time, no decision has been made by either the U.S. or Canada to terminate the Treaty. Similarly, no decision has been made to attempt to renegotiate or otherwise modify the current terms of the Treaty. Absent those decisions, the Entities will continue to collaborate to implement the existing Treaty within their authorities while seeking to more fully integrate mutually beneficial contemporary fish and other environmental and social needs into system operations. The Entities recognize that there are significant issues beyond the basic power and flood control scenarios examined in the Phase 1 studies. The U.S. and Canada will work to hear from regional interests, stakeholders, and sovereigns to define additional scenarios for analysis.

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PREFACE

The Columbia River Treaty is an international agreement between Canada and the United States (U.S.) through which the two nations jointly regulate and manage the Columbia River as it flows from British Columbia into the U.S. The Treaty and an associated Protocol were approved in 1964 (the Protocol provides detailed additional guidance for execution of the Treaty not contained in the Treaty itself; throughout this document, unless otherwise stated, references to the Treaty include the Protocol).

The Treaty established the Canadian and U.S. Entities as the implementing agents for each government. British Columbia Hydro and Power Authority (BC Hydro) was designated as the Canadian Entity responsible for developing and implementing Treaty operating plans. In the United States, the Bonneville Power Administration (BPA) Administrator and the U.S. Army Corps of Engineers (Corps) Division Engineer, Northwestern Division, were designated as the U.S. Entity, with the BPA Administrator designated as U.S. Entity Chair.

The Treaty contains two provisions that take effect on September 16, 2024 (60 years after ratification), and remain in effect thereafter that could impact the current power and flood control benefits achieved by the Treaty. First, Canada's obligation to operate a dedicated amount of storage for a coordinated and pre-determined annual operation for flood control benefits in Canada and the U.S. will end. It is replaced by an obligation to operate any related storage in Canada when "Called Upon" by the U.S. for flood control needs that cannot be adequately met by related U.S. facilities. The U.S. must pay Canada for any Canadian operating costs from the Called Upon operation, as well as for any economic losses to Canada arising directly from forgoing alternative uses of the Canadian storage used for the Called Upon operation.

Second, while the Treaty has no specified end date, it does allow either Canada or the United States the option to unilaterally terminate most of the provisions of the Treaty at any time on or after September 16, 2024, with at least 10 years' minimum notice. Surviving provisions in the case of termination include Called Upon flood control and the coordinated operation of Libby reservoir. Thus, the year 2014 is the latest date that either nation could notify the other of intent to terminate the Treaty and still have termination take effect in 2024.

No decision has been made by either the U.S. or Canada to terminate the Treaty. Similarly, no decision has been made to attempt to renegotiate or otherwise modify the current terms of the Treaty. Absent any decision regarding termination or renegotiation, the Treaty will continue with its current terms indefinitely. However, given the significance of these provisions that will take effect on and after September 16, 2024, it is important that the parties to the Treaty work toward an understanding of the potential implications for post-2024 Treaty planning and Columbia River operations.

Toward that end, Phase 1 of the 2014/2024 Columbia River Treaty Review, the initial modeling and analysis phase, has been conducted as a joint effort between the Canadian and U.S. Entities. The purpose of the Phase 1 studies is to provide information about post-2024 conditions both with and without the current Treaty and from the limited perspective of the two primary purposes of the Treaty—power and flood control.

This report provides the results of the Phase 1 studies and identifies additional potential studies that could add to the understanding of the Treaty's post-2024 provisions. However, there is no commitment by the Entities to conduct any additional studies or to work jointly in conducting any additional studies.

This report was produced by the Columbia River Treaty Operating Committee (CRTOC), with the authorization of the Canadian and U.S. Entities. The Entities have drawn from their respective staffs at BC Hydro, BPA, and the Corps in conducting the Phase 1 studies and preparing this final Phase 1 report.

It is important to remember that while the Entities have been given broad discretion to implement the Treaty, they are not authorized to terminate, renegotiate, or otherwise modify the Treaty. In Canada, international treaties are within the prerogative of the executive branch of the federal government; a treaty may be ratified by parliamentary resolution. In the case of the Columbia River Treaty, Canada has assigned certain rights and obligations relating to the Treaty to British Columbia pursuant to the Canada-BC Agreement (July 8, 1963). In the U.S., authority over international treaties rests with the President, assisted in foreign relations and international negotiations by the Department of State and subject in certain cases to the advice and consent of the U.S. Senate.

Disclaimers

The scenarios included in this Phase 1 Report are identified for analysis purposes only and do not represent a determination, decision, or commitment of either the Canadian Entity or the U.S. Entity or their respective governments concerning any particular position, operation, or other course of action. Furthermore, assumptions used in developing the Phase 1 Report scenarios do not represent the future expected position, interpretation, or perspective on any matter of either Entity or its respective government.

Nothing in this report (including the studies undertaken) sets a precedent or implies agreement by either Entity concerning interpretation of Treaty rights and obligations. In addition, nothing in this report, or actions taken by the Entities and their representatives in preparing this report, represents a past practice or procedure or constitutes a Treaty modification or interpretation that prejudices, changes, or waives in any way Treaty rights and obligations. In preparing this report, the Entities have agreed that:

- Participating in this report is not to be considered as an acknowledgment or admission by either Entity of facts, rights, or obligations that may be implied by preparing the report, any assumptions used in the report, or the results of the report.
- No operating response identified by an Entity as a possible or likely response to any condition is an admission of the required response or is to be considered to limit options that may be available to the Entity or to affect or limit the response of the Entity.
- No assumption used in this report shall be considered to be an acknowledgment or admission by either Entity of facts, rights, or obligations that may be implied by any such assumption

used in the report, and each Entity reserves the future right to challenge any assumption, notwithstanding its use in this report.

- Neither Entity makes any representation or warranty concerning assumptions, inputs, or responses provided to the other Entity in conducting the Phase 1 studies.
- Failure of an Entity to object to an assumption or operating response in this report is not to be considered acceptance of that assumption or operating response.
- Report results are non-binding on the Entities and without prejudice.
- The absence of any scenario, alternative, curve, or similar output in this report is not to be considered an acknowledgment that such scenario, alternative, curve, or output is not valid or relevant to the 2014/2024 Columbia River Treaty Review.

The Treaty does not provide detailed procedures for Called Upon, and there are differences between the Entities with regard to interpretation of Called Upon rights and obligations, including flood control objectives (e.g., 600 kcfs or 450 kcfs). Thus, on a without prejudice basis, two different flow objectives were simulated to provide information regarding a potential range of future operations.

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1. INTRODUCTION

1.1. PURPOSE

Since 1964, the Columbia River Treaty[1] (Treaty or CRT) has provided significant benefits to the United States and Canada through coordinated river management by the two countries. When the Treaty was negotiated, its two primary purposes were to provide substantial flood control and power generation benefits to both countries.

The Treaty contains two[2] provisions that could impact these benefits as early as the year 2024:

1. In 2024, Canadian flood control obligations automatically change from a pre–determined annual operation to a "Called Upon" operation.
2. The year 2024 is also the earliest date that either Canada or the U.S. can terminate most of the provisions of the Treaty, with a minimum 10-years' written notice. Called Upon flood control and a few other Treaty provisions would continue regardless of termination.

The Phase 1 studies are not designed to establish future operating strategies, alternatives to the Treaty, or government policies, but simply to begin the learning process. Both Entities recognize that additional study, analysis, and consultation are required to fully understand the potential implications of future Treaty alternatives. These studies constitute the initial modeling and analysis of the 2014/2024 Columbia River Treaty Review and were designed to investigate and understand the implications of the post-2024 provisions on power and flood control, the two primary purposes recognized in the Treaty. This report describes and discusses the methodologies and assumptions employed; the findings and results; and the risks, limitations, and issues encountered throughout the Phase 1 planning, modeling, and reporting process.

The Entities designed the Phase 1 studies to model post-2024 river operations with three basic approaches:

1. The Treaty continues post-2024 with largely the same Treaty operations as today (Study C).
2. The Treaty continues post-2024 and Called Upon flood control is implemented (Study A).
3. The Treaty is terminated in 2024 and Called Upon flood control is implemented (Study B).

The scope of the Phase 1 studies was purposely very limited. The studies did not include actual operations for fisheries and other uses, as described further in section 2.4. These scenarios should be compared only against each other and not against actual operating conditions.

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[1] A full text of the Columbia River Treaty and Protocol is included in Appendix B.

[2] The Treaty actually contains a third 2024 provision: Canada has a right to divert the Kootenay River above Libby into Columbia Lake to the extent streamflows at the border near Newgate, BC, are not below the lesser of 2500 cfs or natural flow. This diversion option was not examined in the Phase 1 studies.

Expected key outcomes of the studies were to identify, discuss, and evaluate the impacts of these alternative post-2024 scenarios on:

- The Assured Operating Plan (AOP) and Canadian and U.S. power operations
- Future Canadian Entitlement levels (the years 2025 and 2045 were selected for study)
- Estimated benefits, limitations, and impacts of potential Called Upon flood control operations for Canadian storage
- Potential outflows across the border from Arrow and Duncan reservoirs
- Potential end-of-period reservoir elevations and contents for the Treaty reservoirs (Mica/Arrow/Duncan/Libby) and certain U.S. reservoirs (Dworshak/Grand Coulee/Hungry Horse/Brownlee)

1.2. TREATY OPERATIONS PLANNING AND MODELING BACKGROUND

Phase 1 studies required the use (with some modifications) of current Treaty planning models and processes. The following sections are provided to give a general description of the various operating plans and Treaty studies that are currently conducted, along with how they were applied to the Phase 1 studies. For additional detail on current Treaty modeling, refer to Appendix A. A list of acronyms and glossary of terms are included as Appendix C.

1.2.1. FLOOD CONTROL OPERATING PLAN

The Treaty directs the U.S. Entity to develop a Flood Control Operating Plan (FCOP) that guides the operation of prescribed Canadian storage to minimize flood damage in both Canada and the U.S. Last updated in 2003, the FCOP is part of the coordinated operation of Canadian and U.S. projects. The goal of the FCOP is to reduce to non-damaging levels, insofar as possible, the flows at all potential flood damage areas and to regulate to the lowest possible level larger floods that cannot be controlled. Under terms of the Columbia River Treaty, the coordinated flood control operation described in the FCOP continues only through September 16th, 2024, and then is replaced by Called Upon flood control. Details of current flood control operations under the FCOP are contained in Appendix A.

Canadian storage is an integral part of the overall Columbia River reservoir system and is used in coordination with U.S. storage to achieve system flood control objectives. The Treaty FCOP prescribes criteria and procedures for operation of Mica, Duncan, and Arrow reservoirs to achieve flood control objectives in both countries. Libby reservoir is included in the FCOP to meet the Treaty requirement to coordinate Libby operation for flood control protection in Canada and for the system. The Corps ensures that the principles and operating criteria within the FCOP for Treaty storage are consistent with the overall system flood control requirements for the Columbia River. Design of the current system flood control is focused on reducing flows at the reference point at The Dalles, Oregon.

The Columbia River Treaty refers to two types of flood control storage space that is provided by Canadian reservoirs prior to September 16, 2024, Primary Storage and On-Call Storage.[3] The United States purchased 8.45 Maf of Primary Storage through September 2024. Primary Storage space is available on an annual basis and is operated in accordance with procedures and criteria defined in the FCOP. Primary Storage was adjusted in 1995 to 8.95 Maf as part of an optional flood control storage reallocation between Mica and Arrow reservoirs. Prior to September 2024 the Treaty also requires Canada to operate any storage in addition to the Primary Storage in the Columbia River Basin in Canada as required to meet flood control needs in the United States that cannot adequately be met by Primary Storage and flood control facilities in the United States. The Protocol further defines this need prior to 2024 as arising only in the case of potential floods that would result in a peak discharge in excess of 600,000 cfs (600 kcfs) at The Dalles after the use of all related U.S. storage capacity existing and under construction in January 1961, Libby storage, and the Primary Storage. This additional Canadian space beyond Primary Storage is labeled On-Call Storage and can be used in accordance with the Treaty.

When the forecast of unregulated April through August runoff for the Columbia River at The Dalles exceeds the values described in the FCOP, the U.S. Entity may, at its discretion, initiate formal consultation with the Canadian Entity on the need for On-Call Storage. The Treaty requires that the United States pay Canada $1,875,000 for each of the first four calls for On-Call Storage. In addition, the United States will deliver electric power equal to the power lost by Canada as a result of operating the storage to meet the flood control need for which the call was made. The U.S. has never requested On-Call Storage from Canada, mainly because the Primary Storage, combined with annual power drafts, has adequately controlled flood peaks that have occurred since the Treaty projects were completed in 1973. This description is only a summary of the relevant provisions of the Treaty, and is subject to the actual terms, which are provided for reference in Appendix B.

1.2.2. Called Upon Flood Control

After 2024, Canada's obligation to operate Primary Storage for U.S. flood control will end. In place of that obligation, the Treaty allows the U.S. to call upon any Canadian storage for U.S. flood control needs that cannot be adequately met by all related U.S. projects, limited to no greater degree of flood control after 2024 than provided for under the Treaty before 2024. Prior to calling upon Canadian storage, the U.S. must first plan to use all related storage that would be effective in controlling flooding on the Columbia River in the U.S. In addition, for each request, the U.S. must pay the operating costs incurred in providing the flood control and any economic loss arising from Canada forgoing alternative uses of the storage. This description is only a high-level summary of certain provisions of the Treaty, and the reader is referred to the provisions themselves (provided in Appendix B).

The Entities expect that a Called Upon request would be implemented as needed within an

[3] As standard naming conventions used in the FCOP and other implementation plans under the Treaty, the Entities refer to On-Call Storage as this additional Canadian storage needed over and above Primary Storage prior to 2024. Conversely, the term Called Upon refers to the Treaty flood control operation that will occur subsequent to 2024 in which the U.S. may call upon Canada to provide storage to control flooding that cannot be adequately met by flood control facilities in the U.S.

operating year. Therefore, to assess the impacts of Called Upon on the Canadian Treaty projects and U.S. system, Called Upon operations were not modeled in long-term planning studies (AOP) but instead were applied using short-term modeling that more closely approximated real-time flood control operations. This assumption is similar to the current use of On Call flood control as described in the FCOP, which is available to be used in an operational timeframe as may be needed, with no modeling within the long-term AOP studies. How a Called Upon request could be implemented has not been agreed between the Entities.

1.2.3. Assured Operating Plan and Determination of Downstream Power Benefits

The Treaty requires that the Entities prepare annually an Assured Operating Plan for Canadian Storage and the resulting Determination of Downstream Power Benefits (DDPB). These plans are prepared annually for the sixth succeeding operating year. The AOPs are designed to achieve an optimum power operation in both Canada and the U.S. The DDPB calculates the Canadian Entitlement, which is defined to be one-half of the computed downstream power benefits in the U.S.

The AOP operating criteria consist primarily of a series of rule curves and requirements that guide reservoir operations for flood control and optimum power generation. Typically, Canadian Treaty reservoirs are guided by Operating Rule Curves and requirements that ensure flood control, optimum power, and refill for the coordinated system in average and better water years. During low flow conditions, Critical Rule Curves guide reservoir operations for firm power needs. In addition, procedures for flow and storage content objectives at Mica, together with storage and flow limits at Mica and Arrow, help optimize Canadian power generation within the overall system operation.

1.2.4. Detailed Operating Plan

Each year a Detailed Operating Plan (DOP) is prepared for the next operating year. The DOP includes procedures for implementing the AOP and the FCOP. If the Entities agree, the Treaty allows the DOP to include changes from the AOP and FCOP that may produce results more advantageous to both countries. Typically, there are only minor changes from the AOP to the DOP. Instead, the Entities often agree to mutually beneficial deviations from the DOP during the operating year through Supplemental Operating Agreements (SOAs) that meet Canadian and U.S. power, fish, wildlife, recreation, and other interests.

1.2.5. Treaty Storage Regulation

The Treaty Storage Regulation (TSR) is a hydroregulation study that implements the DOP operating criteria. In actual operation, the TSR is updated twice monthly with actual inflows for prior months and forecast unregulated flows, flood control curves, and refill curves for future months. Operation of Canadian storage is implemented by the Entities agreeing each week on the total of Arrow plus Duncan outflows. These outflows are based on drafting or filling Canadian reservoirs to end-of-month storage levels determined by a TSR study, as may be modified by any SOAs. For the purposes of the Phase 1 studies, no SOAs or DOPs were modeled; therefore, the operating criteria used in the TSR modeling were directly from the AOP.

1.2.6. Canadian Flexibility Operations

Treaty power operating plans specify individual project operations for each of the three Canadian storage projects, but the obligation to operate Canadian storage is fulfilled through a monthly reservoir balancing relationship for the whole of Canadian storage. Canada has the flexibility (Flex) to operate individual projects for maximum Canadian benefits, so long as the sum of Arrow plus Duncan outflows is the same as that specified in the TSR. Thus, to correctly evaluate the changes in Canadian operations and assess the effect of Called Upon flood control on Canadian generation, a Flex operation was assumed for the studies in which the Treaty continues. Typically, a Flex operation is a reservoir operation that better meets the needs of British Columbia. Post-2024, as flood control requirements shift from FCOP to Called Upon, the ability for Canada to shift water between Canadian reservoirs increases as the Canadian Flex operation is no longer restricted by the annual primary flood control obligation.

Figure 1-1 shows an example of how Mica is drafted deeper within the Operating Year compared to the TSR. The deeper draft at Mica represents the shift of water from Mica to Arrow. As shown in Figure 1-2, Arrow is kept higher than the TSR would indicate to maximize generation at that project. While there is no impact to the U.S. from this operation in terms of amount or timing of flows coming across the border, it could have implications for Called Upon implementation, as described in section 3.4.4.6.

Figure 1-1 – Example of a Mica Flex Operation Compared to TSR Operation

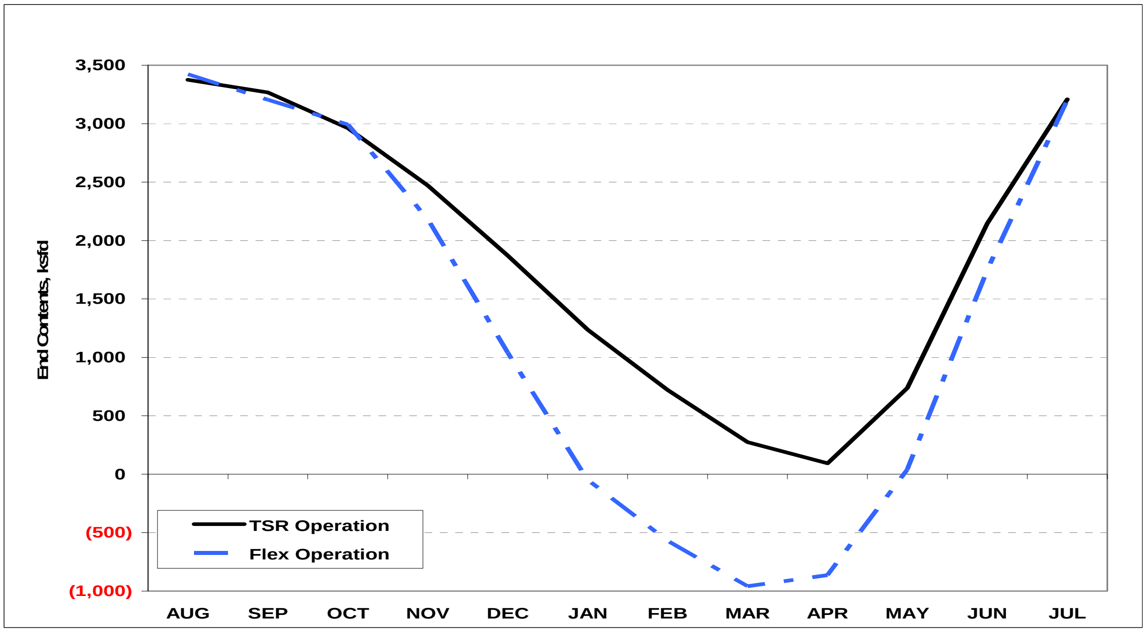
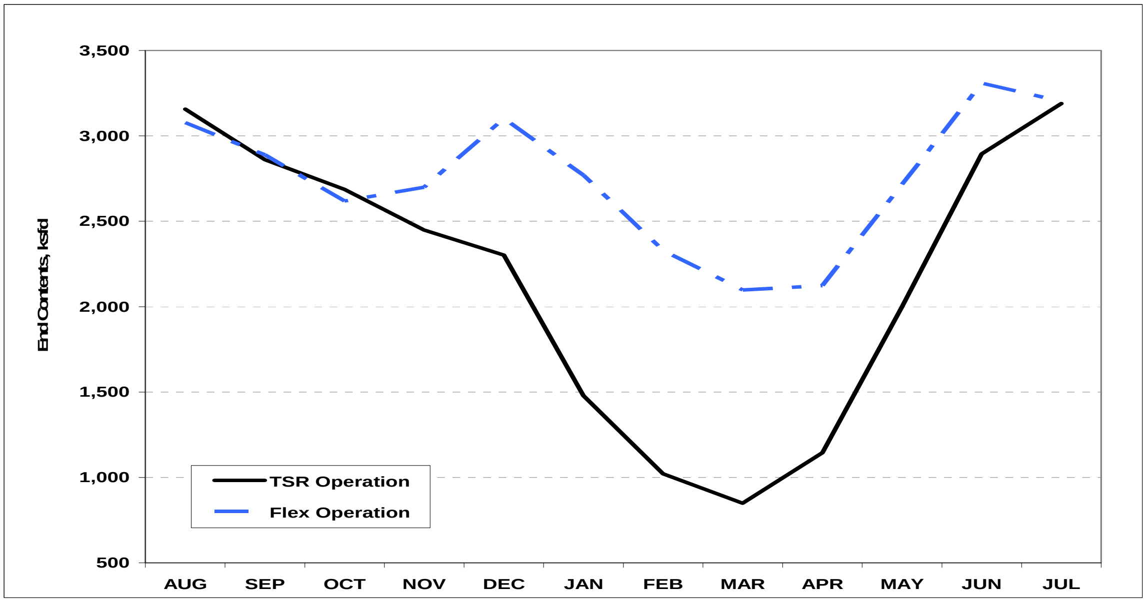


Figure 1-2 – Example of a Corresponding Flex Operation for Arrow



1.2.7. Power Impact Studies

In order to assess the impacts of Called Upon on operations, power impact studies were performed assuming Called Upon was implemented. Since Called Upon operations were assumed to be implemented in short-term operations planning, it was important to model their implementation using TSR studies with Canadian Flex operations. The power impact studies most closely resemble a TSR study. However, it was recognized that since the TSR is a monthly study it could not adequately capture true real-time implementation, but instead would provide a general assessment of the impacts of Called Upon with and without the Treaty-specified power operation.

1.2.8. Other River Uses, Operations, and Agreements

The Phase 1 studies looked at modeling Treaty planning as it pertains to power and flood control only. Therefore, the Phase 1 study results for Canadian and U.S. reservoirs were not necessarily representative of how the projects would be operated in actual operations. Most Canadian and U.S. reservoirs are operated not only for power and flood control, but also for fish, wildlife, recreation, and other non-power/non-flood control uses. For many of these operations, the key driver has been for the benefit of fish. Examples of operations for fish include:

- Libby white sturgeon and bull trout release
- Vernita Bar protection flows for salmon
- McNary fish flow objectives for salmon
- Chum operation in fall and winter below Bonneville Dam
- Spill for fish at U.S. projects
- Operation of projects to no lower than flood control level (or minimum flow) during the fall through spring to improve flows for fish

- Draft of projects during the summer to enhance flows for fish
- Whitefish and trout spawning incubation flows below Arrow

These additional uses of the river are addressed through SOAs under the Treaty and its DOPs for within-year operations when mutually beneficial. There have been numerous SOAs entered into over the years, from a few in the 1970s to usually one or more every year since the mid-1990s.

The Libby Coordination Agreement (LCA) is another agreement under the Treaty that often has resulted in operations that help address operations for fish on an annual basis. The LCA was entered into by the Entities in February 2000 to help resolve issues at that time concerning the operation of Libby Dam. Additional annual agreements have been entered into for use of Canadian non-Treaty storage (i.e., space at the Treaty projects in Canada that is not operated under the Treaty) when mutually agreed upon to provide for fish flows and other uses.

SOA, LCA, and non-Treaty operations are implemented on a year-to-year basis and not normally included in long-term Treaty planning studies. Accordingly, SOA, LCA, and non-Treaty operations were not included in the modeling for these studies.

2. STUDY APPROACH

2.1. OVERVIEW OF PHASE 1 STUDIES

For these Phase 1 technical studies, the Entities agreed to limit the scope of the analyses to the three studies described below:

Study A - Treaty Continues: The Treaty was assumed to continue post-2024 with its current provisions. Under this study, Canadian flood control obligations changed from the current prescribed annual operation of a dedicated amount of storage to an assumed Called Upon operation. Assured Operating Plans for power benefits and Canadian Entitlement provisions were assumed to continue, but modifications to current procedures would be required to reflect revised Canadian flood control obligations.

Study B - Treaty is Terminated: The Treaty was assumed to terminate in 2024 with no replacement agreement. The U.S. payment by means of the Canadian Entitlement would end, as would the requirement for Canada to regulate flows for U.S. power interests. Canadian flood control obligations changed from the current prescribed annual operation of a dedicated amount of storage to an assumed Called Upon operation (same principles as Study A). Absent the Treaty obligation to coordinate for power, Canada could operate its projects for Canadian power, flood control, and other benefits. For the purposes of Study B, two Canadian operational scenarios were developed to depict a range of possible flows across the border into the U.S. One scenario represented a Canadian operation with minimal Canadian draft, for local flood control only, and one scenario represented a Canadian reservoir draft for power production in Canada. Many other scenarios are possible, including different operations from year to year.

Study C - Continuation of Pre-2024 Conditions: The Treaty was assumed to continue post-2024 with the existing pre-2024 Flood Control Operating Plan, Assured Operating Plan, and Canadian Entitlement procedures. The initial long-term purchase of prescribed annual flood control operation by the Canadian projects constructed under the Treaty is set to expire in 2024 independent of potential Treaty termination. Study C is not consistent with the existing Treaty language because it assumes the current coordinated FCOP operation would continue post-2024. Therefore, new arrangements (e.g., an extension or replacement of the current flood control purchase) would be required to implement these study conditions. Study C was conducted to provide a basis for comparison with current operations.

2.2. DESCRIPTION OF STUDIES

Table 2-1 provides additional information about each study in Phase 1.

Table 2-1 – Comparison of Phase 1 Studies

	Study A: Treaty Continues	**Study B: Treaty is Terminated**	**Study C: Continuation of Pre-2024 Conditions**
Overview	Treaty continues post-2024 with its current provisions. Canadian flood control obligations change from the current assured annual operation to a Called Upon operation. This study forecast what the AOP, Canadian and U.S. power and flood control operations, and Canadian Entitlement, might look like under these conditions post-2024.	The Treaty is terminated in 2024 and Called Upon flood control is implemented. This study assessed two potential Canadian operational scenarios—one with minimal Canadian draft, for local flood control only; and one with reservoir draft specifically for power production in Canada.	Treaty continues with the current AOP, FCOP, and Canadian Entitlement procedures. This study forecast the AOP operating criteria and resulting Canadian and U.S. power and flood control operations, and the Canadian Entitlement, assuming the CRT continues with the existing pre-2024 provisions.
Flood Control	➢ Called Upon flood control based on regulating flows at The Dalles to a maximum flood control objective (450 kcfs or 600 kcfs).[4] ➢ Libby standard flood control draft. ➢ Hungry Horse VarQ[5] flood control draft. ➢ A1 Study: Grand Coulee flood control includes adjustment for Canadian upstream power draft. ➢ A2 Study: Grand Coulee flood control includes adjustment for upstream flood control draft only.	➢ Called Upon flood control based on regulating flows at The Dalles to a maximum flood control objective (450 kcfs or 600 kcfs). ➢ Libby VarQ flood control draft. ➢ Hungry Horse VarQ flood control draft. ➢ B1 Study: Grand Coulee flood control includes adjustment for Canadian flood control draft ➢ B2 Study: Grand Coulee flood control includes adjustment for Canadian power draft	➢ Mimics the current Annual FCOP procedures. ➢ Libby standard flood control draft. ➢ Hungry Horse VarQ flood control draft. ➢ Grand Coulee flood control includes adjustment for upstream flood control draft.

[4] Refer to section 2.3.2.2 for a description of the U.S. Flood Control Objectives.
[5] Refer to section 3.4.2 for a description of VarQ and standard flood control operations.

Table 2-1 – Comparison of Phase 1 Studies			
	Study A: Treaty Continues	**Study B: Treaty is Terminated**	**Study C: Continuation of Pre-2024 Conditions**
Loads and Resources	Projected loads and resources for 2024-25.	Projected loads and resources for 2024-25.	Projected loads and resources for both 2024-25 and 2044-45.
Assured Operating Plan (AOP)	➢ Performed using current methodology, without the Canadian primary flood control obligation. ➢ Based on 2024-25 operating year. ➢ Performed critical period and 70-year hydroregulation studies using current methodology.	➢ No AOP. Instead, Canadian operation for power and flood control in Canada only, and U.S. operation modeled with an AOP-like study using assured fixed Canadian operation. ➢ Performed critical period and 70-year hydroregulation studies using current methodology. ➢ Based on 2024-25 operating year.	➢ Performed using current methodology. ➢ Based on 2024-25 and 2044-45 operating years. ➢ Critical period and 70-year hydroregulation studies performed for 2024-25 only. ➢ 2044-45 AOP study streamlined based on 2024-25 study work.
Canadian Entitlement (DDPB)	Performed critical period and 30-year studies for determining Canadian Entitlement for 2024-25 operating year.	Canadian Entitlement discontinued.	Performed critical period and 30-year studies for determining Canadian Entitlement for 2024-25 and 2044-45 operating years.
Called Upon Power Impact Study	TSR-like studies were performed to assess power impacts due to Called Upon operation	TSR-like studies were performed to assess power impacts due to Called Upon operation	No power impact assessments were done for this study.
Simulation Mode	➢ A1: Both observed and forecast. ➢ A2: Observed only	➢ B1: Observed and forecast. ➢ B2: Forecast only.	➢ Observed mode only.

Table 2-1 – Comparison of Phase 1 Studies

	Study A: Treaty Continues	Study B: Treaty is Terminated	Study C: Continuation of Pre-2024 Conditions
Key Assumptions and Factors	➢ AOPs and Canadian Entitlement provisions continue, but modifications to current procedures would be required to reflect the different Canadian flood control obligations. ➢ Called Upon is considered a real-time operation and is not modeled in the planning studies but instead occurs in power studies and real-time modeling.	➢ U.S. flood control operation treats Canadian power draft as assured, even though it is not assured with Treaty termination. ➢ Called Upon is considered a real-time operation and is not modeled in the planning studies but instead occurs in power studies and real-time modeling.	➢ The current FCOP remains in place; however, new arrangements (e.g., an extension or replacement of the current flood control purchase) would be required to implement these study conditions. ➢ This study was conducted to provide a basis for comparison with current operations and to model the potential change in Canadian Entitlement over time.

2.3. OVERVIEW OF STUDY SCENARIOS

2.3.1. SCENARIO DESCRIPTIONS

The three Phase 1 studies were analyzed using 13 different scenarios. The scenarios were designed to test and compare a range of possible situations with varying 1) study time horizons, 2) flood control maximum flow objectives, 3) AOP procedures, and 4) observed mode and forecast mode water supply and inflow forecast procedures. Table 2-2 lists each scenario analyzed as part of the Phase 1 technical studies.

Table 2-2 – Scenarios Analyzed as Part of Phase 1 Technical Studies

Study A - Treaty Continues				
Scenario	Abbrev. Name	Time Horizon	Flood Control Objective	Simulation Mode
Called Upon and AOP procedures	A1O600	2024-25	600 kcfs	Observed
Called Upon and AOP procedures	A1O450	2024-25	450 kcfs	Observed
Called Upon and TSR procedures	A1F600	2024-25	600 kcfs	Forecast
Called Upon and TSR procedures	A1F450	2024-25	450 kcfs	Forecast
AOP procedures	A2O600	2024-25	600 kcfs	Observed

Study B - Treaty is Terminated				
Scenario	Abbrev. Name	Time Horizon	Flood Control Objective	Simulation Mode
Canadian Local Flood Control	B1O600	2024-25	600 kcfs	Observed
Canadian Local Flood Control	B1O450	2024-25	450 kcfs	Observed
Canadian Local Flood Control	B1F600	2024-25	600 kcfs	Forecast
Canadian Local Flood Control	B1F450	2024-25	450 kcfs	Forecast
Canadian Power Draft	B2F600	2024-25	600 kcfs	Forecast
Canadian Power Draft	B2F450	2024-25	450 kcfs	Forecast

Study C - Continuation of Pre-2024 Conditions				
Scenario	Abbrev. Name	Time Horizon	Flood Control Objective	Simulation Mode
Current FCOP and AOP procedures	C2025	2024-25	ICF[6]	Observed
Current FCOP and AOP procedures	C2045	2044-45	ICF	Observed

The naming convention for the abbreviated names of the different scenarios under Studies A and B is as follows:

- The first character (A or B) identifies which Phase 1 study, as described in section 2.1.
- The second character:

[6] Initial controlled flow (ICF) is a controlled flow designed to prevent reservoir space from filling too soon, which may result in damaging uncontrolled flows. See Appendix A for more details.

  - For A studies identifies the method used to address the Grand Coulee flood control adjustment (1 = upstream power draft used, 2 = Canadian local only used).
  - For B studies identifies the Canadian operation used in the scenario (1 = Canadian local flood control only, 2 = Canadian power draft).
- The third character (O or F) designates whether the study was conducted in observed or forecast mode.
- The last three characters refer to the flood control maximum flow objective used (450 or 600 kcfs) at The Dalles.

For example, A1O600 is an A study using upstream power draft for the Grand Coulee flood control adjustment, done in observed mode, and using 600 kcfs as the flood control maximum objective.

In Study C, scenarios were completed for operating year 2024-25 (C2025 or C25) and operating year 2044-45 (C2045 or C45). The purpose of Study C was to provide a basis to compare and investigate the Canadian Entitlement under pre-2024 conditions. The current flood control operations were continued after 2024, there was no Called Upon operation, and forecast mode studies were not simulated.

Under Study B, Treaty is Terminated, it was assumed that there would no longer be coordinated planning between Canada and the U.S. through the FCOP or AOP. In that case, Canadian operations from year to year would be highly uncertain. To address that uncertainty, two scenarios were developed to evaluate certain possible future Canadian operations. For the B1 studies, it was assumed that the Canadian projects were operated principally for local flood protection in British Columbia. In the B2 studies, the projects were operated to a Canadian power draft, which was provided by BC Hydro for study example purposes only. The assumptions used to model the “B1” and “B2” scenarios are:

- **B1 Scenarios: Canadian Local Flood Control.** Canada operated its storage projects for Canadian local flood control needs only; Mica, Duncan, and Arrow reservoirs were held at higher, more stable elevations without deep seasonal power drafts. The Canadian local flood control objectives were based on assumed Canadian flood level criteria.
- **B2 Scenarios: Canadian Power Drafts.** Canada operated its storage projects for Canadian power and local flood control only. Drafting the projects to meet Canadian power needs with annual refill provided corollary flood control and power benefits downstream in the U.S. The power drafts developed for the Phase 1 studies were treated as an assured operation, although in reality there would be no assurance that the projects could or would be operated in this manner if the Treaty was terminated.

2.3.2. SCENARIO ASSUMPTIONS AND VARIATIONS

2.3.2.1. Study Horizons

All studies were conducted for the 2024-25 operating year. In addition, Study C modeled the 2044-45 operating year to estimate the decline in the computed downstream power benefits.

2.3.2.2. U.S. Flood Control Objective

In studies that reflected a shift to a Called Upon flood control operation (Studies A and B), a maximum flood control flow objective for the Lower Columbia as measured at The Dalles, Oregon, was the primary factor directing the flood control operation of the entire Columbia River system once Called Upon was activated. The Treaty does not provide detailed procedures for Called Upon, and there are differences between the Entities with regard to interpretation of Called Upon rights and obligations, including flood control objectives (i.e., 450 or 600 kcfs). Thus, without prejudice, two different flow objectives were simulated to provide information regarding a potential range of future operations. According to the current FCOP, flooding begins around 450 kcfs in the lower Columbia, while major damages begin around 600 kcfs. Scenarios with maximum flood control objectives of 600 kcfs and 450 kcfs at The Dalles were conducted in Studies A and B.

While Studies A and B used a specified maximum flow objective at The Dalles, Study C was based on the current FCOP, which calculates an ICF at The Dalles based on changing forecasts of peak flow, residual volume, and upstream storage.

2.3.2.3. Grand Coulee Flood Control Adjustment

The existing AOP procedures were used in Study C, including an adjustment to Grand Coulee's flood control curve based on only the upstream flood control draft. In actual operations, Grand Coulee's flood control curve is adjusted for the additional power draft at upstream reservoirs. The difference is significant for the operation of Grand Coulee but has only a small impact on Canadian storage operations.

For Study A, two scenarios were completed reflecting a much smaller Canadian local flood control draft. In Study A1, the existing AOP procedures were modified to account for the power draft at Canadian projects. In Study A2, the Step I Joint Optimum study was repeated without the Grand Coulee adjustment for Canadian power draft. Other procedures for conducting AOP studies post-2024 are possible but were not explored in the Phase 1 studies due to time limitations.

Study B, with two scenarios of Canadian storage operations, used the total draft of Canadian storage, whether for power or flood control, even though those drafts are not assured, to adjust Grand Coulee's flood control curve.

2.3.2.4. Simulation Mode

Flood control regulation studies can be simulated in observed mode and forecast mode (as described below). Application of these two modes comes into play in two modeling periods: 1) during the drawdown period in order to provide reservoir space for the anticipated spring runoff and 2) during the reservoir refill period to reduce runoff peaks and provide for assured refill of the reservoirs.

Observed mode. In observed mode, reservoir regulation decisions are assumed to be made with "perfect foresight" of all future runoff volumes and inflows across the entire Columbia Basin. Modelers draft and refill the system with complete knowledge of the volume and shape of the inflows during each period. Studies conducted in observed mode do not consider the uncertainty inherent in actual operations and will therefore tend to underestimate the storage required for flood control (or alternatively will provide less-effective flood control for the available storage space). For AOP and other planning studies, the Entities have always used observed mode to optimize the critical period operation and determine flood control and refill curves.

Forecast mode. In forecast mode, modelers use historical water supply forecasts and associated errors to determine the drawdown of the reservoirs, thus incorporating runoff volume uncertainty and error into the modeling of the system. During refill, the system modelers make reservoir regulation decisions with a limited forward-looking time window to emulate the uncertainty of streamflow forecasting. Forecast mode is generally used for short-term planning, in actual operation such as the TSR, or whenever the uncertainty associated with runoff forecasting must be considered.

For the Phase 1 studies, all AOP studies were performed in observed mode, just as is done in actual Treaty planning. The various scenarios were generally done in both observed and forecast mode; forecast mode is more appropriate when trying to reflect how Called Upon and Canadian Flex would actually be implemented.

2.4. CRITICAL CONSIDERATIONS NOT INCLUDED IN THE PHASE 1 STUDIES

Other River Uses. Analysis of the benefits and impacts associated with the alternative scenarios described in the Phase 1 studies was strictly limited to the two primary purposes authorized under the Treaty—power generation and flood control. For these preliminary studies, there was no incorporation of other operating purposes and benefits related to the Columbia River system, including but not limited to fisheries, wildlife habitat, recreation, irrigation, water supply, water quality, and navigation.

Global Climate Change. The potential effect of global climate change on the benefits and operations of the Columbia River system in Canada and the U.S. is an important regional consideration. The potential impacts of climate change on the future timing and volume of precipitation in the Columbia River Basin and possible impacts on reservoir system operations were not incorporated into the Phase 1 studies.

Economic Costs and Benefits. The Phase 1 studies utilized a monthly time-step model to estimate the potential power impact. Since at least a daily time-step model is required to estimate impacts on both firm energy and capacity, the Phase 1 studies did not include any calculation of the economic benefits or costs of scenarios for hydropower. Potential future generation quantities under the scenarios were estimated, but no dollar values were placed on that generation. Likewise, flood control operations were described in terms of effects on reservoir storage, required Canadian storage for Called Upon, and peak flows at The Dalles and other locations in the system, but these Phase 1 studies did not calculate flood damages prevented or economic losses (opportunity costs) associated with flood control storage operation under the scenarios.

2.5. RISKS AND LIMITATIONS OF STUDIES

While careful attention and expertise went into modeling and projecting what the future may hold in 2024-25 and as far out as 2044-45, there are always risks and limitations to those projections. These risks and limitations apply to all aspects of defining the future, including models, scenarios, and assumptions. The results of the Phase 1 studies contain useful preliminary information; however, it is important to recognize that caution should be used in interpreting the data. Areas where risks, uncertainty and limitations can be found include but are not limited to:

- **Methodologies and Requirements of Called Upon:** Since the actual implementation of Called Upon post-2024 was not expected to be defined through this effort, the modeling of Called Upon in the Phase 1 studies was a combination of new approaches and current methodologies. There may be differences between the Entities on interpretation and implementation requirements under the Treaty, and it is likely that Called Upon implementation will be different from what was defined in the Phase 1 studies.
- **Power Load and Resource Assumptions:** Load and resource assumptions play a key role in all aspects of Treaty planning and modeling as well as in assessing the capabilities of the U.S. system if the Treaty is terminated. Projections of loads and resources for the Phase 1 studies included assumptions and estimates based on information available at the time of development. As with any forecast, the numbers have an associated risk and uncertainty around them.
- **Modeling and Procedural Assumptions:** The Phase 1 studies adopted current modeling techniques and methodologies where possible and feasible. Some modeling procedures evolved over time as understanding of the studies increased, such that not all procedures were consistent across the studies. Places where it is known that procedures impacted the results are identified throughout the report. Modeling and procedures will need to be evaluated and modified for any future studies.
- **Future Canadian Operating Scenarios:** Only two scenarios were modeled regarding possible Canadian operations under the Treaty is Terminated assumption. It is recognized that this does not capture the full range of possibilities, or even the most likely possibility.

3. METHODS AND RESULTS

3.1. INTRODUCTION

This section 3 summarizes the procedures used and the results obtained from the Phase 1 studies. It describes potential future conditions related to flood control and hydropower after 2024 under the three alternative studies: Study A, Treaty Continues; Study B, Treaty is Terminated; and, Study C, Continuation of Pre-2024 Conditions. The focus is on comparing and contrasting the various scenarios.

Section 3 is structured as follows:

Section 3.2 summarizes how power loads and resources were developed and how the assumptions influenced the outcomes of the power studies and estimates of Canadian Entitlement after 2024 in the Phase 1 studies.

Section 3.3 summarizes the long-term planning results for the AOPs, DDPBs, and Canadian Entitlement under Studies A and C.

Section 3.4 summarizes how Called Upon flood control was modeled in the short- and long-term studies and the resulting Called Upon operations and impacts to the Canadian and U.S. systems.

Section 3.5 compares and contrasts the relative impacts of Called Upon in the various scenarios, both with and without the Treaty, on reservoir storage and elevations in both Canada and the U.S., outflows from Arrow and Duncan, and power generation.

Section 3.6 summarizes the 70-year generation differences between scenarios.

3.2. POWER LOADS AND RESOURCES

3.2.1. INTRODUCTION

Electrical loads and resources are an important driver in the development of hydropower operating plans. The net result of the determination of the loads and resources is the Residual Hydro Load[7] for the coordinated hydropower system to meet. The amount and shape (month to month) of that load has a direct impact on the development of Canadian and U.S. storage operating criteria, actual storage operations, and the calculation of the Canadian Entitlement.

Loads are defined as the amount of electrical power required to be delivered to a given point to meet demand. Resources are generation installations that are needed to meet the forecast loads and include a variety of energy sources such as hydro, thermal (e.g., coal, natural gas, nuclear), and renewables (e.g., wind, solar).

[7] Residual Hydro Load is the net result of PNWA loads, thermal installations, and other resources; a residual load for the coordinated hydropower system to meet.

For the purposes of the Phase 1 studies, forecast loads and resources were developed for the U.S. Pacific Northwest Area (PNWA)[8] as defined in the Treaty. Two sets of loads and resources were forecast. The first was developed for the period August 2024 through July 2025 and was applied to all three Phase 1 studies (Studies A, B, and C). The second set of loads and resources, developed for the period August 2044 through July 2045, was used only in Study C to forecast changes to the Canadian Entitlement over time. Both sets included the effect of energy conservation.

Developing a set of loads and resources for the Phase 1 studies involved numerous steps and assumptions because of the complexity of the power system and the uncertainty in forecasting the future. Market forces, new regulations, and political decisions will shape the future physical limits, transmission constraints, and environmental requirements. This section summarizes the Phase 1 study methodology used to develop the PNWA loads and resources, the forecast results, and risks associated with these forecasts.

3.2.2. PROCEDURES AND ASSUMPTIONS

Procedures used for determining the loads and resources for 2024-25 and 2044-45 are similar to those used in the most recent studies for the Assured Operating Plan, i.e., AOP 2013-14 (AOP14).

Loads for AOP studies are the PNWA firm load, plus the estimated flow of power at points of interconnection with adjacent areas (imports and exports), minus miscellaneous resources. Miscellaneous resources include many small PNWA hydropower projects, wind, and other non-thermal resources. Resources include the Canadian Treaty storage, coordinated Canadian facilities, the Base System[9] hydropower projects, and other coordinated hydropower projects and coordinated thermal installations. Maintenance and transmission losses and peak reserves are subtracted from the resources.

The loads and resources are based on the median forecast from BPA's January 2008 draft of the 2007 Pacific Northwest Loads and Resources Study (White Book).[10] The White Book has been used for most AOP load and resource data since 1994 and is an accepted regional standard for BPA contract and ratemaking purposes. Data from the White Book included in the Phase 1 studies are energy and capacity forecasts for:

- PNWA regional load
- Firm exports and imports
- Thermal generating installations
- Miscellaneous generation including wind, small hydro and other renewables

[8] The Pacific Northwest Area is Oregon, Washington, Montana west of the continental divide, and Idaho, except areas served in September 1964 by the California-Oregon Power Company (now part of PacifiCorp) and Utah Power and Light Company (now Rocky Mountain Power).
[9] The 24 projects listed in the Treaty, plus post-1961 projects added on the mainstem of the Columbia.
[10] Study #50, which is the same as the 2007 BPA White Book published in March 2008 (available at www:bpa.gov) except for minor updates that were included in the published document.

A complicating issue in forecasting the loads and resources is that the U.S. hydropower system has fisheries requirements that are not included in AOP studies. As a result, the PNWA hydropower system in the AOP has about 1000 aMW more energy capability than it does in actual operations, where fisheries requirements must be met. With the Treaty requirement for balanced loads and resources, the AOP studies must necessarily serve different loads and/or include different resources from those shown in the White Book to balance this inconsistency between Treaty planning and actual operations. For the AOP studies, some of the White Book load and resource data is therefore adjusted to meet Treaty requirements. The most significant include:

- Canadian Entitlement exports are adjusted to the expected results for the Phase 1 studies.
- Seasonal exchanges (imports and exports that balance on an annual basis) are added to account for the difference in annual shape between the hydropower generation from an AOP study and the generation from actual U.S. operations that are affected by fishery requirements.
- Wind and other renewable resource forecasts from the White Book are increased as needed to meet renewable portfolio standards for Oregon, Washington, and Montana.
- Thermal installations[11] are adjusted to balance loads and resources.
- Hydro and thermal maintenance, transmission losses, and capacity reserves are adjusted to reflect the difference between AOP and White Book loads and resources.

An iterative process is required to determine the Residual Hydro Load and the generic thermal installation,[12] which is sized to balance the loads and resources. A hydroregulation simulation is conducted to determine the critical period[13] and the Firm Energy Load Carrying Capability (FELCC)[14] of the hydropower system. In this power study the reservoir operation is adjusted to maximize its ability to meet the Residual Hydro Load. If the FELCC is less than the Residual Hydro Load, imports are added or the generic thermal installation is increased to balance the loads and resources. Conversely, if the FELCC is greater than the Residual Hydro Load, exports are added or the generic thermal installation is reduced to balance loads and resources. This iterative procedure adjusts the generic thermal installation until the Residual Hydro Load equals the system FELCC determined by the Step I critical period studies.

[11] Thermal resources include Columbia Generating Station (CGS), a nuclear generating facility located in the State of Washington.

[12] Generic thermal installations represent all individual existing and potential thermal projects, with the exception of Columbia Generating Station

[13] Critical period is the historical streamflow period over which 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.

[14] FELCC is the critical period energy capability shaped the same as the firm load, except any surpluses or deficits are shaped to match desired load or resource adjustments.

3.2.3. STUDY C LOADS AND RESOURCES

The calculation of Study C loads for the 2024-25 and 2044-45 operating years is shown in Table 3-1. Data from AOP14 is provided as a comparison.

Table 3-1 – Forecast Loads for AOP14, C2024-25, and C2044-45

U.S. System Loads (aMW)	AOP14	AOP C2025	AOPC2025 - AOP14	AOP C2045	AOPC2045 - AOPC2025
PNWA Firm Load	22803	26280	3477	34700	8420
Total Exports [1]	1605	1434	-171	1630	196
Total Imports [2]	-1177	-1213	-37	-2099	-886
Miscellaneous Resources	-2841	-5404	-2563	-6454	-1050
AOP Load	20390	21097	707	27778	6681

1) Exports are the sum of the firm contracts with California, plus British Columbia, plus seasonal exchanges.
2) Imports are the sum of forecast firm contracts, imports from British Columbia and California needed for White Book firm energy deficits, and seasonal exchanges.

The 2024-25 average annual PNWA firm load was up 3,477 MW from 2013-14 (the last completed AOP), which is a 1.5 percent average annual load growth from the White Book base case operating year (2006-07). The forecast firm loads for the 20 years beyond 2024-25 increased at an annual rate of 1.4 percent per year, for a total increase of 32 percent or 8,420 MW. There is little change in the forecast amount of exports in comparing 2013-14, 2024-25, and 2044-45 because the seasonal load shape did not change across the studies. Imports increased from 2024-25 to 2044-45 to help meet load growth. Miscellaneous resources increased by 90 percent from 2013-14 to 2024-25 and by 19 percent from 2023-24 to 2044-45.

Study C resources are summarized in Table 3-2. The resources were set equal to the net system load by adjusting the amount of thermal installations and imports and exports. Data from AOP14 is provided as a comparison.

Table 3-2 – Resources for AOPs for 2013-14, 2024-25, 2044-45

U.S. System Resources (aMW)	AOP14	AOP C2025	C2025 – AOP14	AOP C2045	C2045 – C2025
Coordinated Hydro Resources [1]	11057	11025	-32	11025	0
Thermal Installations	10031	10853	823	17785	6932
Maint, trans. losses, & resrv. [2]	-697	-781	-84	-1032	-241
AOP Resources	20390	21097	707	27778	6681

1) Hydro resources based on 1928-29 flows.
2) Maintenance, transmission losses, and reserves are shown as negative, so increases are shown in the difference column as a larger negative value.

Hydropower capability for Study C was the same for 2024-25 and 2044-45, because there were no changes in the assumptions for installed capacity, irrigation depletions, non-power constraints, and Residual Hydro Load shape. Transmission losses and peak reserves are a fixed percentage of the energy and capacity loads, so they increase over time.

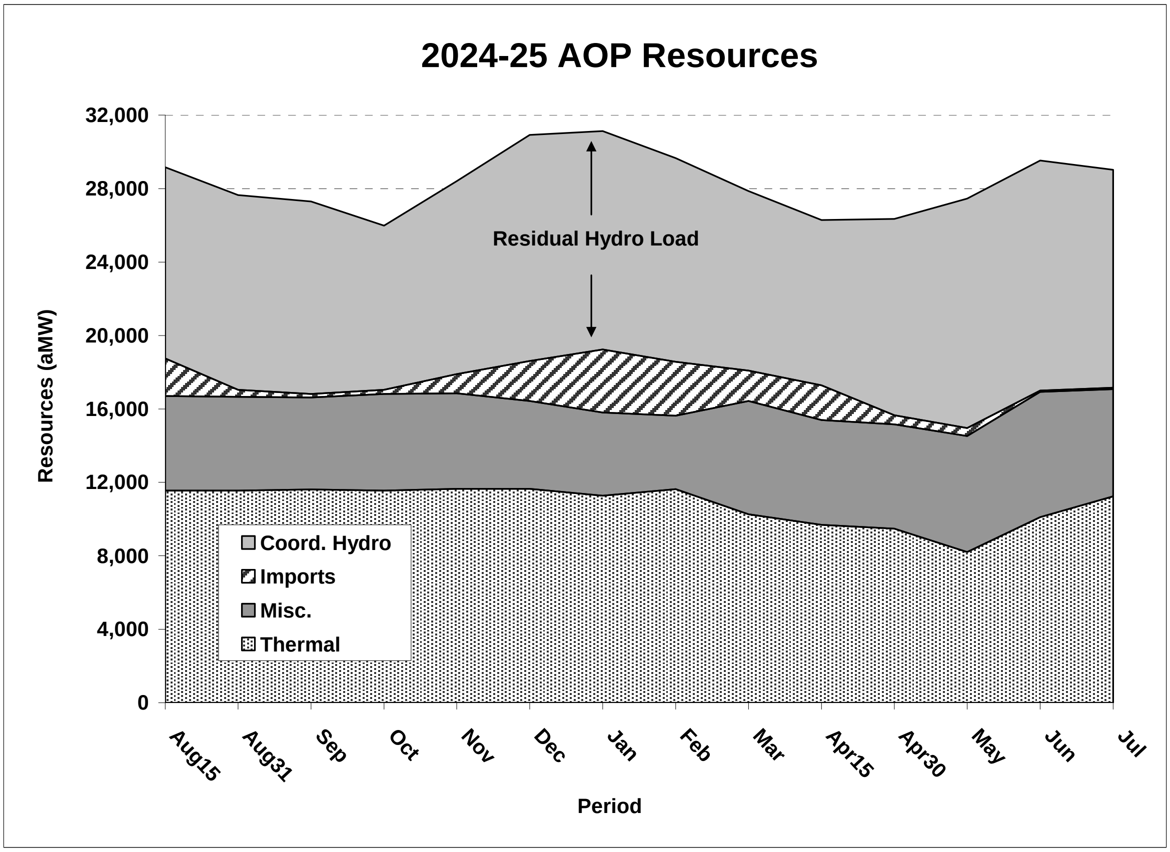
Thermal installations included Columbia Generating Station (878 aMW) and the generic thermal installation sized as needed to balance the loads and resources, as described in section 3.2.2. As a result of all the other assumed load and resource changes, the total thermal installations for Study C were up 8.2 percent from 2013-14 to 2024-25, and up 64 percent from 2024-25 to 2044-45. For the period from 2013-14 to 2023-24, the PNWA firm load increase (+3477) was met primarily by the addition of wind and renewable resources (+2563). From 2024-25 to 2044-45, the firm load increase (+8420) was met primarily by thermal resources (+6932) and wind and renewables (+1050).

The generic renewable resources (not currently planned or built) added are those required to meet the Montana, Oregon, and Washington Renewable Portfolio Standards (RPS) implemented in 2006 and 2007. RPSs are state policies that require electricity providers to obtain a minimum percentage of their power from renewable energy resources by a certain date. With increased focus on renewable energy the assumed percentage of renewable may increase in the future. In particular, the large increase in thermal resources from 2024-25 to 2044-45 may not be consistent with initiatives that are currently being investigated by government entities such as the Western Climate Initiative.[15]

The coordinated hydro resources (i.e., resources to meet the Residual Hydro Load) amount was not significantly different for AOPs for operating years 2013-14, 2024-25, and 2044-45 because the seasonal exchanges were designed to reflect the difference between AOP and real-world hydro capability. The portions of AOP system load met by coordinated hydro, imports, miscellaneous resources, and thermal installations are shown in Figure 3-1.

[15] The Western Climate Initiative is a collaboration of independent jurisdictions working together to identify, evaluate, and implement policies to assess and address climate change at a regional level. This comprehensive effort seeks to reduce greenhouse gas pollution, spur growth in new green technologies, help build a strong clean-energy economy, and reduce dependence on foreign oil (www.westernclimateinitiative.org)

Figure 3-1 – 2024-25 Resources for Study C



3.2.4. LOAD/RESOURCE DIFFERENCES BETWEEN STUDIES A, B, AND C

The hydro system operation in Studies A, B, and C varied depending on whether the Canadian storage was operated for joint optimum power (Treaty Continues) or power in Canada only (Treaty is Terminated). There are also differences due to the flood control operations in each study. In response to changes in the hydro system operation the exports, imports, and thermal installations also changed between Studies A, B, and C. As described in section 3.2.2, the generic thermal installation was adjusted so that the Residual Hydro Load was equal to the FELCC. The different values for exports, imports, and thermal installations shown in Table 3-3 reflect the differences in loads and hydropower capability between the studies.

Table 3-3 – Changes to Exports, Imports, Hydro Capability, & Thermal Resources between Studies A, B, and C

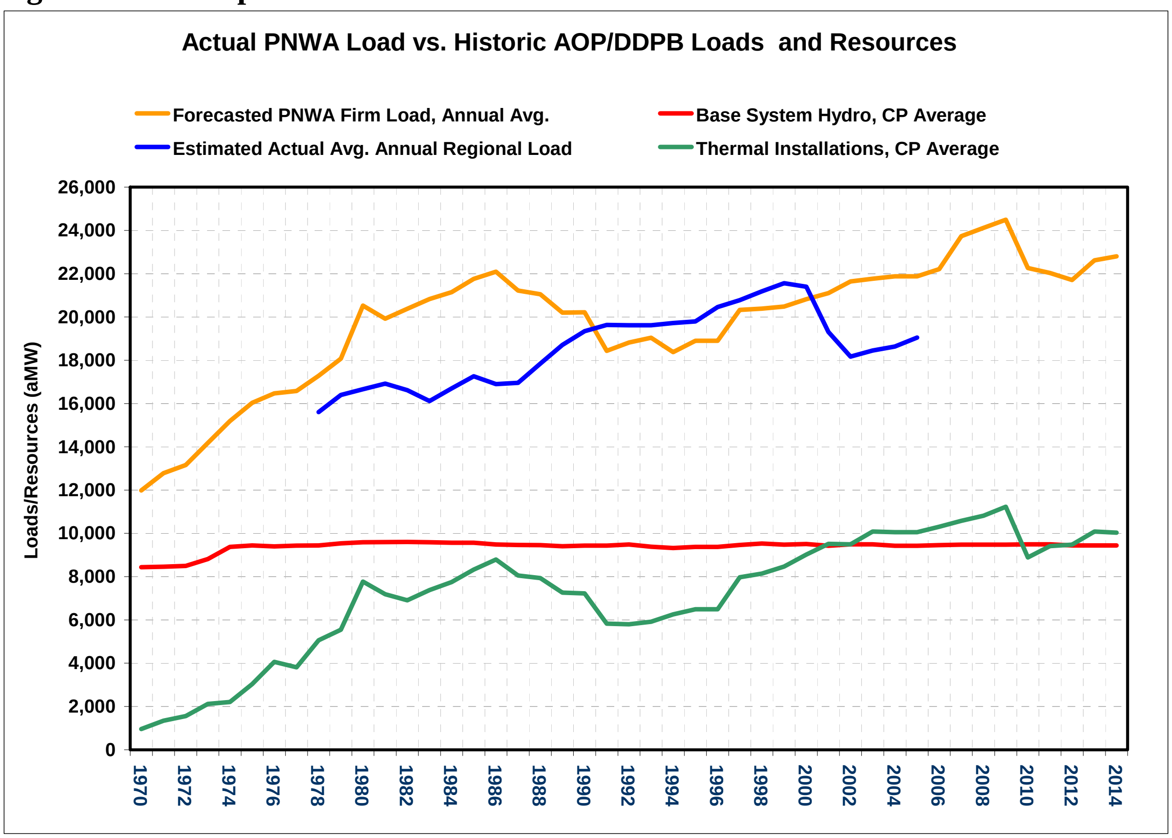
(aMW)	Study C	Study A1	Study B1	Study B2
Exports	1434	1434	1005	1005
Imports	-1213	-1213	-784	-784
Firm Hydro Capability	11025	11031	9411	11094
Thermal Installations	10853	10846	12466	10784

Study A and Study C used identical loads and resources except for small changes in thermal resources needed to respond to changes in hydropower capability. This confirmed the assumption that with the Treaty, changes to flood control post-2024 will not significantly affect the firm load that the system can support. Under Study B (Treaty is Terminated), the amount of firm load that the system can support is dependent on how Canada decides to operate (i.e., scenario B1, B2, or other).

3.2.5. Risk and Uncertainty in Forecasts of Loads and Resources

The process of forecasting loads and resources for the sixth succeeding operating year in AOP studies is highly uncertain. The forecasts are a function of many interrelated factors that are affected by the overall economy, power markets, political policy and laws, and social trends. Extending these forecasts to 2024-25 and 2044-45 operating years is even more speculative. Forecast errors have had a significant impact on the Canadian Entitlement calculation. Figure 3-2 compares historical PNWA firm load used in past AOP studies with actual regional firm loads. The load forecast error is as much as 20 percent in some years. Hydro and thermal resources used in AOP studies are also provided in Figure 3-2 (in the legend, CP means Critical Period).

Figure 3-2 – Comparison of Actual PNWA Firm Loads to AOP Loads and Resources



Other factors that were not studied or explored in the Phase 1 studies that could potentially have significant impact on loads and resources, and consequently impact the Canadian Entitlement, are:

- **Future resource mix within the PNWA:** The allocation between thermal installations and renewable resources in the future is highly uncertain, as is the need for reserves for variable output resources such as renewables.
- **Imports and exports:** Building for export or buying imports is dependent on the relative costs of new resources in different regions, transmission availability, and government regulations.
- **Type of thermal installations and maintenance schedule:** The type of thermal installation (e.g., coal vs. combustion turbine) can affect the determination of the critical period due to the different plant factors (ratio of average to peak generation). The assumed maintenance schedule has a large impact on the Residual Hydro Load.
- **Future non-power constraints:** Changes in non-power constraints for non-Base System hydropower projects can result in changes to loads and resources in AOP studies. Changes in non-power constraints for Base System hydropower projects can decrease the actual power benefits at U.S. projects in Study B, but not the Canadian Entitlement in Studies A and C.
- **Methods for transition from an energy-constrained system to a peak-constrained system:** As the PNWA loads increase, and variable output resources (e.g., wind) are added, it is expected that the power system will become peak or capacity deficit. The current procedures for determining peak load-resource balance, which use instantaneous hydro peak capability, 11 percent peak load reserves, and full reservoir draft during the critical period, may not be adequate and thus require development of new procedures. This could result in a change in Canadian storage operating criteria and a change in the calculation of the Canadian Entitlement.

3.3. ASSURED OPERATING PLAN AND DETERMINATION OF DOWNSTREAM POWER BENEFITS FOR STUDIES A AND C

3.3.1. INTRODUCTION

This section presents the forecast of post-2024 AOPs and Canadian Entitlement for the Phase 1 scenarios Treaty Continues (Study A) and Continuation of Pre-2024 Conditions (Study C). Some information from Study B, Treaty is Terminated, with no AOP and no Canadian Entitlement, is reported for comparison. The primary topics addressed are:

- Procedures and assumptions for development and modeling of the AOP/DDPB post-2024
- Flood control rule curves for AOP studies, and the effect of different assumptions on the AOP results
- AOP operating criteria and results of 70-year hydroregulation studies
- Canadian Entitlement results for the 2024-25 and 2044-45 operating years
- Risk and uncertainty for forecasting future AOP/DDPB study results

The Treaty requires the Entities to agree annually on an AOP and the resulting downstream power benefits for the sixth succeeding operating year. Except for occasional daily flood control operations, the AOP is the default plan for the operation of Canadian storage unless the Entities otherwise agree. Typically the Entities do agree in the Detailed Operating Plan, and other agreements, to allow some changes from the AOP. But all such agreements are based on negotiations that measure incremental benefits from the (default) AOP operation. AOPs are developed to provide flood control and power benefits and do not include many of the requirements for fish and other non-power objectives.

The AOP is defined in the Treaty as Step I of the AOP/DDPB process. It is based on hydroregulation studies of the operation of Canadian storage and other projects in Canada,[16] the U.S. Base System, and the coordinated hydropower projects and other generating resources in the U.S. PNWA. The AOP study process develops operating criteria for Canadian and U.S. reservoirs and simulates the operation over the 70-year historical streamflow record years from August 1928 to July 1998.[17]

The DDPB procedures calculate the Canadian Entitlement. The DDPB is based on two hydroregulation studies that measure power benefits in the U.S. Base System with and without Canadian Treaty storage. The two studies are referred to in the Treaty as Step II and Step III of the DDPB process. The Canadian Entitlement is one-half the increase in downstream U.S. power benefits between the Steps II and III studies. Once calculated by the DDPB studies, the Canadian Entitlement cannot be changed and must be delivered regardless of actual loads, resources, streamflows, or other factors affecting the actual benefits.

The Treaty has detailed requirements for AOP/DDPB studies, which are explained in Appendix A. The loads and resources that are input to the AOP studies are discussed in section 3.2.

3.3.2. PROCEDURES AND ASSUMPTIONS

The current procedures and assumptions for conducting AOP studies and Canadian Entitlement calculations are described in Appendix A and were used without significant change for Studies A and C. The only exception is the change to Canadian and U.S. flood control rule curves, which were modified in Study A to reflect the post-2024 changes to flood control.

Flood control upper rule curves (URCs) define the maximum end-of-month elevation at each reservoir during the evacuation and refill periods. The URCs are derived from system flood control studies and are used as reservoir upper limits for power operations in AOP regulation studies. Adapting URCs for post-2024 flood control provisions and examining the effects on Canadian storage and Grand Coulee operation were important procedural questions explored in the Phase 1 studies.

[16] Other Canadian projects: Revelstoke, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile, Waneta, Corra Linn, and Kootenay Canal.

[17] In accordance with the Treaty, only the 30-year streamflow record from August 1928 to July 1958 is used to develop AOP operating criteria and measure the downstream power benefits.

There are two significant changes to the URCs used in the AOP/DDPB studies for Study A that distinguish Study A from Study C, which uses current methodology. These two changes—use of Canadian Local URCs for Mica, Arrow, and Duncan, and incorporation of the Grand Coulee adjustment—are described in the following sections. The Phase 1 studies assumed that Called Upon flood control storage operations are not included in the AOP but instead are implemented as an operational decision during the operating year.

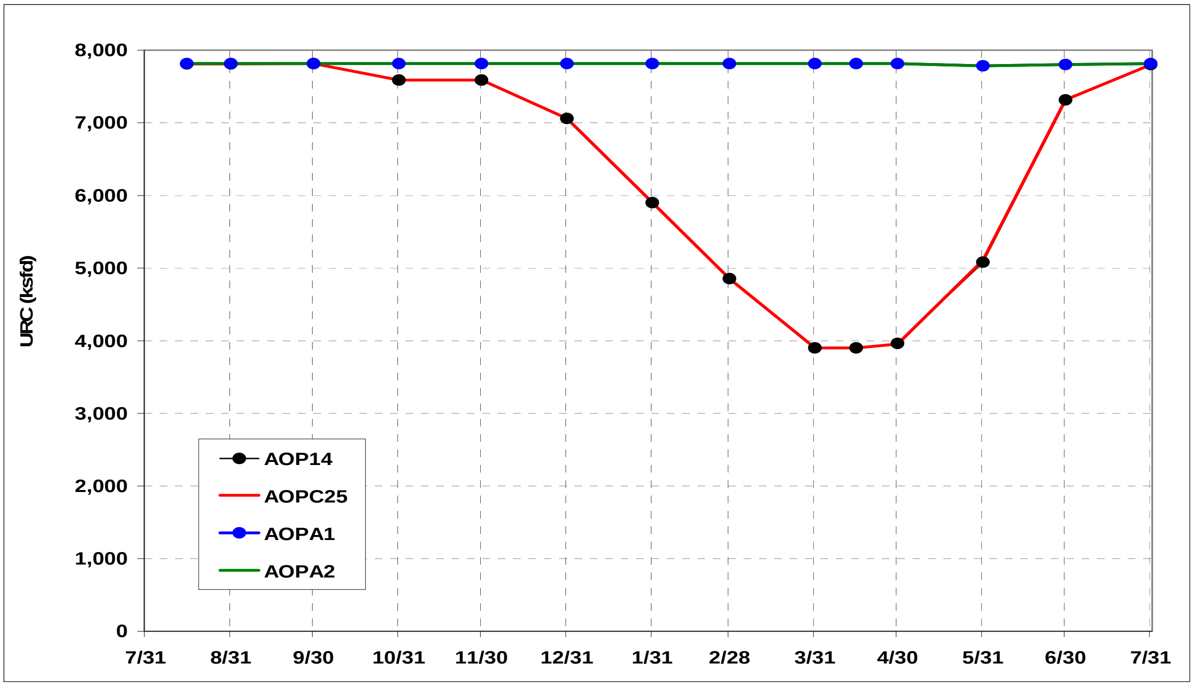
3.3.2.1. Use of Canadian Local Upper Rule Curves in AOP and DDPB Studies

Study C, Continuation of Pre-2024 Conditions, used URCs based on the procedures described in the FCOP. In Study A, the Canadian flood control URCs were based on Canadian local flood control needs only. The contrast between the Study A and Study C URCs is shown in the 70-year average composite Canadian flood control rule curves on Figure 3-3. The average local Canadian flood control draft in Study A is so small that it is not noticeable in the graph. The URCs used in AOP14 are also shown on the graph and are identical to those in Study C.

AOP/DDPB procedures use the same flood control URCs for AOP (Step I) and DDPB (Steps II and III) studies.[18] This approach was applied to Study A and Study C, where all three Steps were conducted. However, future procedures could be done differently. For example, different flood control URCs could be used in each step because the numbers of reservoirs and storage volumes are significantly different in the Steps I, II, and III systems. Due to limited time and resources for the Phase 1 studies, alternative procedures for the Step II and Step III flood control URCs were not explored.

[18] The URCs developed for Step I are used in Steps II and III. However, some of the Step II and III URCs look different because of adjustments for the different storage levels between the Steps I, II, and III systems.

Figure 3-3 – Comparison of Composite Canadian URCs, 70-yr Avg



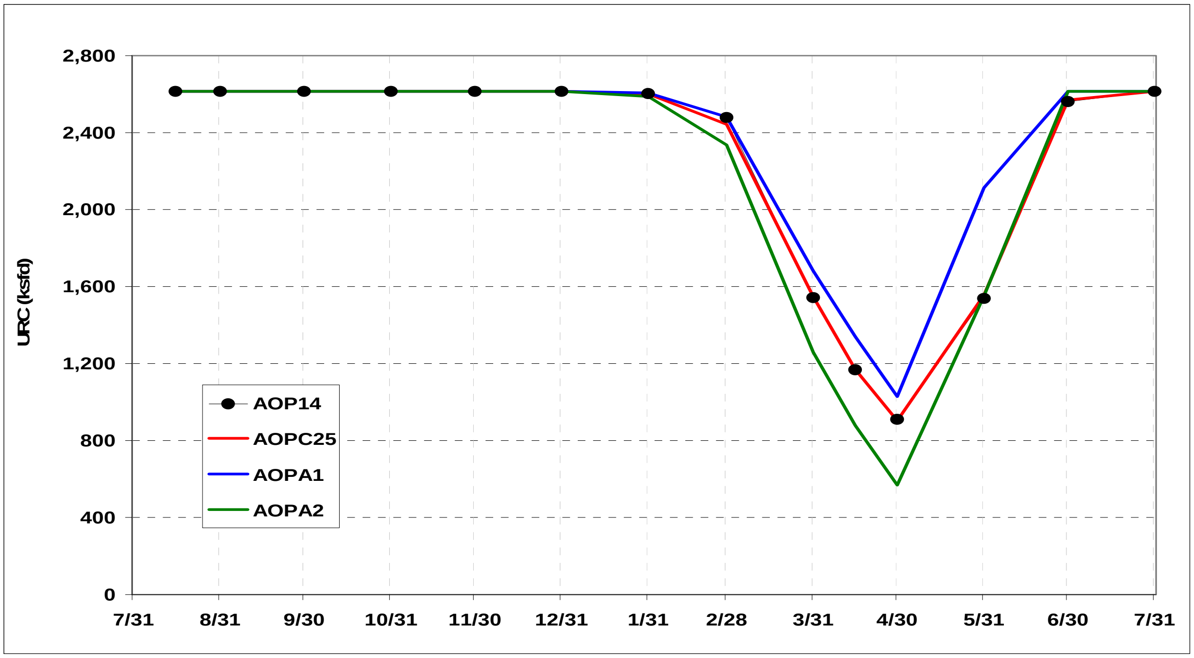
3.3.2.2. Grand Coulee Upper Rule Curve Adjustment in AOP and DDPB Studies

A procedural change from current AOPs made in Study A was to include the adjustment to raise Grand Coulee's flood control rule curve as a result of additional draft for power below URCs at upstream Canadian reservoirs. This adjustment for upstream power drafts has been included in actual operations since the early 1970s but is not included in AOPs. Incorporating the adjustment in AOPs would require iterative studies, and although the higher Grand Coulee flood control rule curves result in an increase in U.S. power generation, the adjustment has had little impact on the operation of Canadian storage in current AOP's.

Study C reflects how flood control is implemented in current AOP/DDPB modeling, where the Grand Coulee adjustment is based only on current flood control draft at upstream reservoirs. The additional draft for power was not included. In Study A, the difference between the Canadian local URC and the additional AOP power draft at Canadian projects is much larger and therefore was expected to have some impact on Canadian storage operations. To evaluate these different approaches to the Grand Coulee adjustment under post-2024 conditions, two scenarios, A1 and A2, were completed. In A1, the adjustment was based on the upstream Canadian power draft, whereas in A2 the adjustment was based on the (much smaller) Canadian local flood control draft. Comparison of scenarios A1 and A2 provides a way to assess the impacts of using the power draft adjustment to Grand Coulee flood control rule curves. Only the AOP Step I was conducted for A2; the DDPB Step II and III studies were not conducted due to time and resource constraints.

The Grand Coulee URCs for Study C and the A1 and A2 scenarios are shown in Figure 3-4, with AOP14 included for comparison. The use of Grand Coulee upstream power draft adjustment in A1 resulted in higher Grand Coulee URCs in comparison to Study C and those used in past AOPs. Study C and scenario A2 both use the Canadian URCs to calculate Grand Coulee's URCs; Study C used the FCOP for Canadian URCs, and A2 used the Canadian local flood control curves. Since the Canadian flood control draft in A2 was very small (local flood control needs only), the Grand Coulee URCs were lower than those in previous studies.

Figure 3-4 – Grand Coulee 70-Year Average URC



3.3.3. Results of AOP Studies

The AOP study results are the Canadian and U.S. operating criteria and the simulated operation of Canadian and U.S. reservoirs over the 70 historical water years. In general, the AOP study results and operating criteria for Studies A and C were quite close, as these studies used the same PNWA load shape from the same BPA White Book, and the same resources, refill parameters, 2000 modified flow, operating constraints, and so on. Furthermore, seasonal exchanges were used to produce similar Residual Hydro Loads. The key differences among these studies were the Canadian flood control curves and the amount of Canadian draft space used for the Grand Coulee flood control adjustments. Even though the 70-year annual average generation, regulated flows, and storages were very close, there are noticeable differences among the year-to-year monthly regulated flows and the monthly flow shapes.

3.3.3.1. AOP Operating Criteria

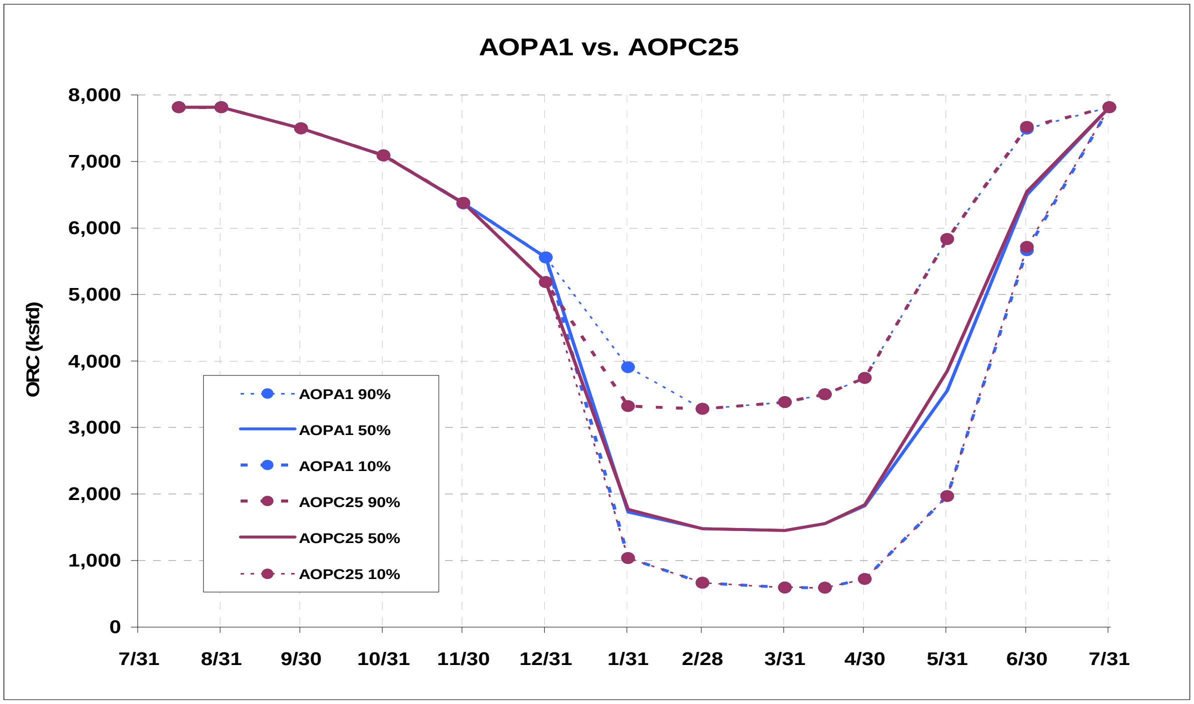
The first process in developing AOP operating criteria is the iterative process of balancing loads and resources in the critical period that was described in section 3.2.2. The storage contents during the critical period become critical rule curves that guide proportional[19] draft of the coordinated reservoir system during future low flow sequences. Typically, proportional draft to meet firm loads occurs about one-quarter to one-third of the time.

There was no significant difference in FELCC among the A1, A2, and C scenarios. For scenarios A1 and C, this is because the Canadian local flood control rule curves were much higher than (were significantly above) the critical period reservoir contents, so the different flood control assumptions did not control Canadian storage operations. In these low flow years, the operation was driven by power needs. In scenario A2, the Grand Coulee flood control adjustment resulted in lower Grand Coulee flood control curves, which in turn caused its critical rule curves to be lower and also resulted in changes to the critical rule curves at other projects. This resulted in a slight decrease in the FELCC.

The second process is refill studies, which determine ORCs that guide reservoir operations for optimum production of secondary energy in the U.S. while maintaining a 95 percent confidence of reservoir refill. Secondary energy, also referred to as non-firm energy, is power that can be generated in years that are wetter than those experienced in the critical period. The refill criteria ensure capability to meet future firm loads. Typically, ORCs guide reservoir operations in about two-thirds to three-fourths of the water conditions. Figure 3-5 shows the 70-year average total Canadian ORC (also called Energy Content Curve or ECC) for scenarios A1 and C. The result of this process is referred to as the U.S. Optimum study.

[19] Each reservoir has a critical rule curve for each year in the critical period. When additional draft is needed to produce the hydro FELCC of the U.S. system, the Canadian Treaty Storage and all reservoirs in the U.S. system are drafted proportionally between their respective Operating Rule Curves and their first Critical Rule Curves. If additional storage is required after system reservoirs reach their first Critical Rule Curves, the proportional draft is made between their first and second Critical Rule Curves, their second and third Critical Rule Curves, and so on.

Figure 3-5 – Total Canadian ORC (70-year average)

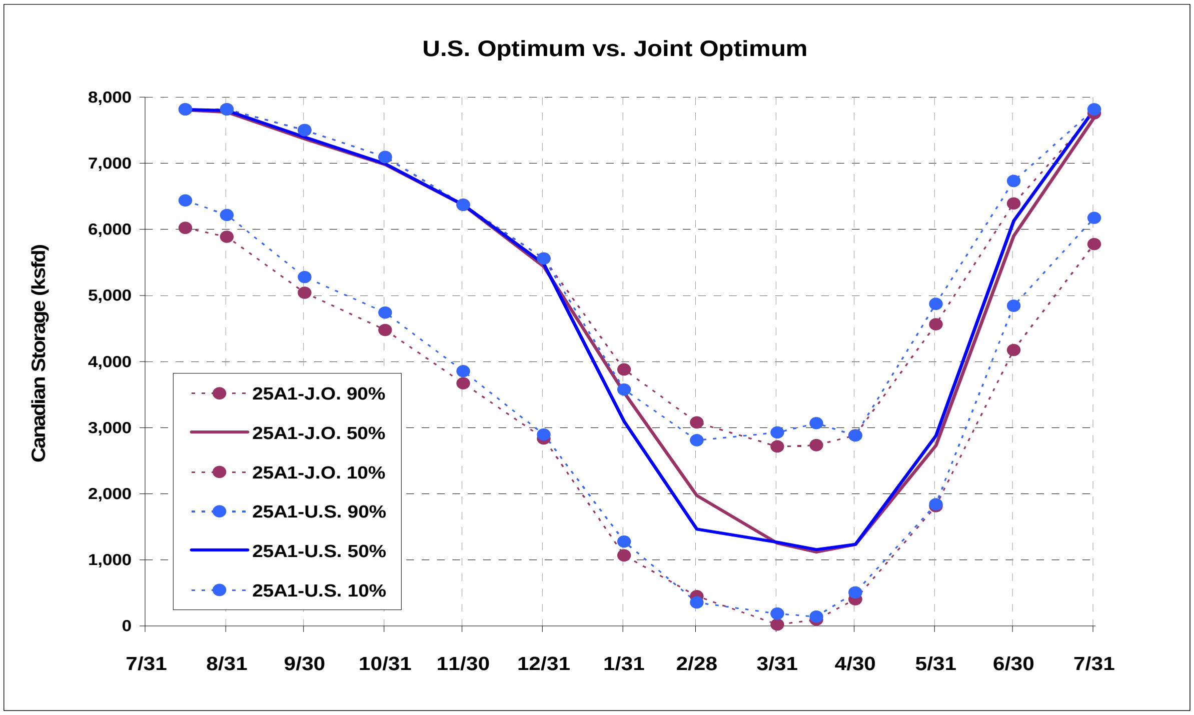


The Composite Canadian Operating Rule Curves were essentially unchanged among scenarios A1, A2, and C except during low water years, when the ORCs were slightly higher in January due to Canadian storage not being constrained by U.S. flood control. The resulting effect on winter flows is discussed in section 3.3.4.2.

The third and last process is the Mica/Arrow Re-operation, which produces the Joint Optimum study. The Mica/Arrow Re-operation optimizes Canadian generation such that the joint Canadian and U.S. hydropower system capability is increased, sometimes at the expense of de-optimizing the U.S. system generation. The Mica/Arrow operating criteria do not always produce the same net flow at the border as the U.S. Optimum. The Joint Optimum operation flows at the border vary from the U.S. Optimum in about 36 percent of the months over the 70 modeled water years.

The results of the Mica/Arrow Re-operation for Studies A and C are similar to AOP14 and prior AOPs. Figure 3-6 compares the results of the U.S. Optimum operation with the Joint Optimum operation. Figure 3-6 shows slightly higher Canadian storage in January and February (due to added maximum outflow limits) for median levels, and lower storage contents in June and July in the Joint Optimum operation.

Figure 3-6 – 70-Year AOPA1 Total Canadian Storage



3.3.3.2. 70-Year Simulation Studies Using AOP Operating Criteria

The final AOP Joint Optimum hydroregulation study simulates the operation of Canadian storage over the 70 historical water years using AOP operating criteria. Figure 3-7 shows the composite 70-year average Canadian storage contents for scenarios A1, A2, and C. AOP14 values are shown for comparison. In general, AOP14 and Study C are very similar except that Study C resulted in slightly deeper draft during August through January. Scenarios A1 and A2 are almost the same as each other. There were differences in average Canadian storage draft between Study C and scenarios A1 and A2, due mainly to changes in the ORC. The ORC differences do not appear to be due to the changes in critical rule curves but instead due to changes in the flood control curves. These ORC differences probably could have been eliminated had the full ORC optimization studies been completed.

Figure 3-7 – 70-year Average Composite Canadian Storage

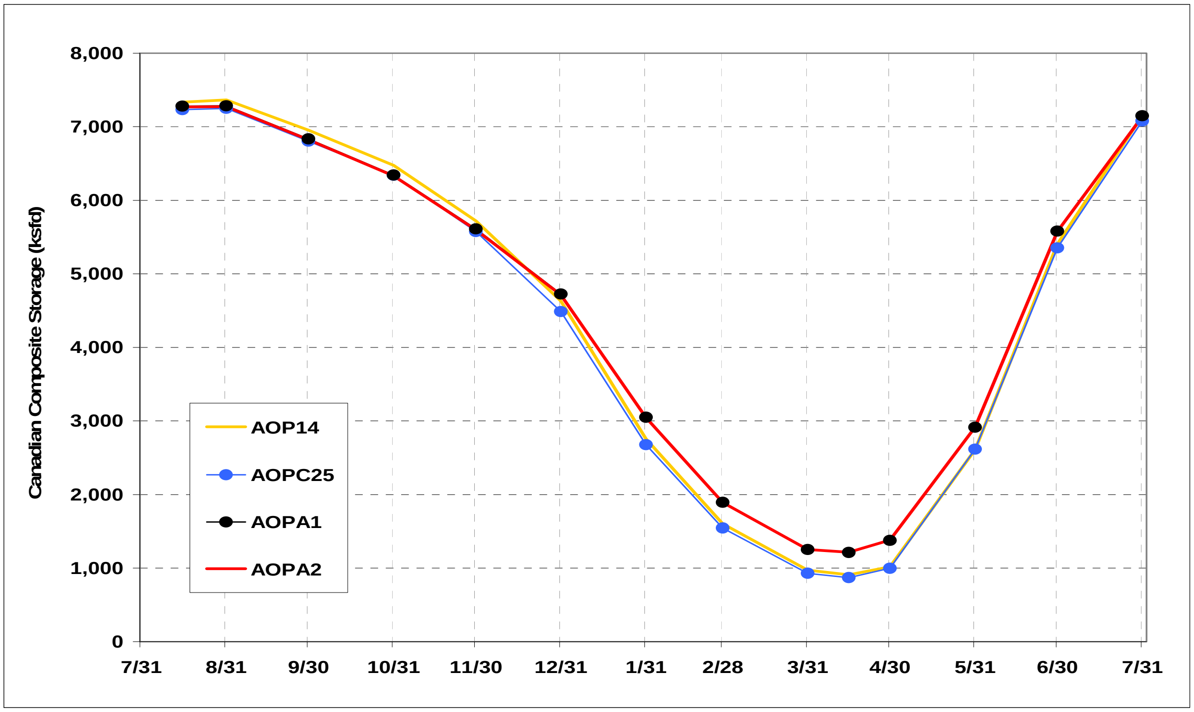


Figure 3-8 shows a comparison of the net Arrow plus Duncan 70-year average regulated outflows between the four scenarios. The changes are similar to and reflect the difference in storage operations shown in Figure 3-7. AOP14 and Study C are almost the same. Scenarios A1 and A2 are almost the same as each other. Scenario A1 compared to Study C shows lower outflows in December-January and higher in May-July. These differences were caused by changes to the flood control rule curves and because no refill study was performed to adjust the ORCs. Refill studies are typically performed to optimize the ORCs during the refill period.

Figure 3-8 – Arrow plus Duncan 70-Year Average Outflows

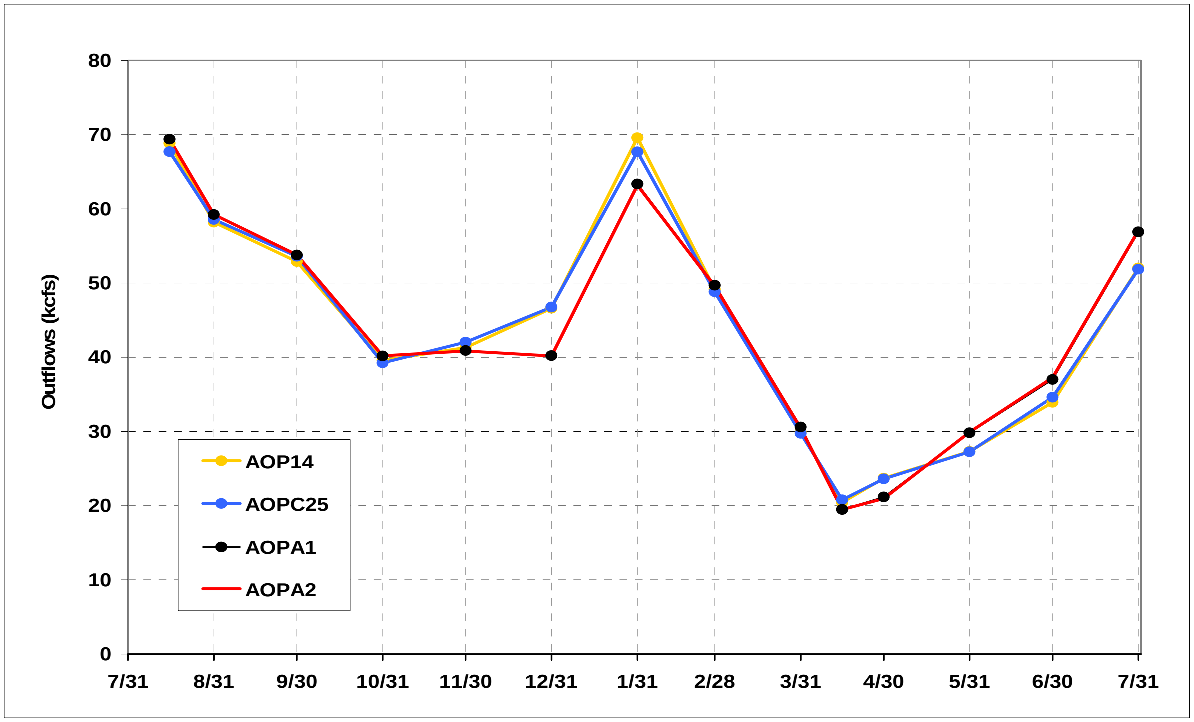
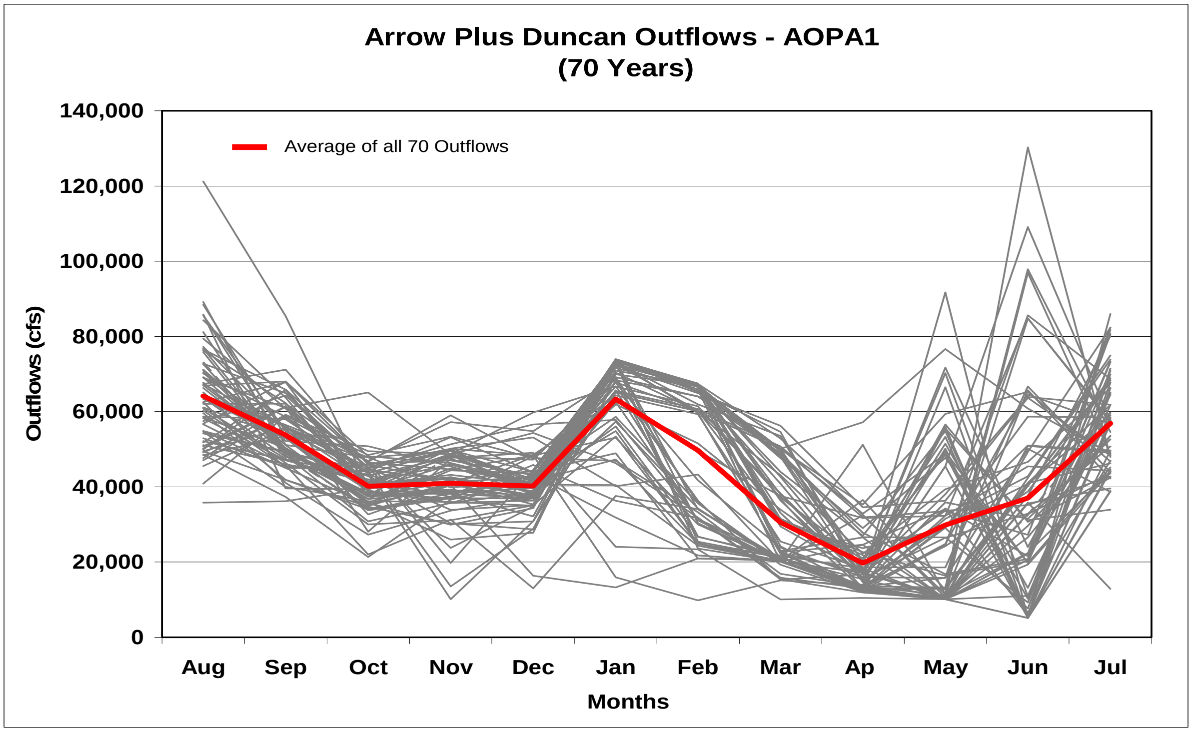


Figure 3-9 is an example of the volatility surrounding these 70-year averages.

Figure 3-9 – Arrow plus Duncan Outflows



The Canadian and U.S. generation values from AOP14 and the A1, A2, and C scenarios are shown in Table 3-4. The reduction in generation between AOP14 and Study C is due mainly to a decrease in Hungry Horse storage, updated flood control curves, and updated generation capacity. The changes between Study C and scenarios A1 and A2 are in general very small. Scenario A1 shows slightly more Canadian generation than Study C. Scenario A2 shows slightly less U.S. generation than scenario A1.

Table 3-4 – AOP Joint Optimum Results (aMW)

70-year Avg.	AOP 14	Study C	Study A1	Study A2	Study C minus AOP14	StudyA1 minus Study C	Study A2 minus Study A1
Canadian Generation	3287	3275	3281	3281	-12	6	0
U.S. System Generation	15402	15346	15340	15339	-56	-6	-1
U.S. Federal Generation	9476	9434	9433	9433	-42	-1	0

3.3.4. Results of DDPB Studies and Calculation of Canadian Entitlement

The DDPB is based on two hydroregulation studies that measure power benefits in the U.S. Base System with and without Canadian Treaty storage. The two studies are referred to in the Treaty as Step II and Step III of the DDPB process.

When the Treaty was negotiated in the 1960s, negotiators recognized that power benefits created by reservoir storage would diminish over time as growth in regional power demand is met by thermal installations. The procedures used in the calculation of the DDPB reflect these principles; an explanation of why this occurs is provided in the following paragraph.

The operation of Canadian storage increases the amount of U.S. Base System usable energy.[20,21] Thermal installations are sized to meet load assuming only firm hydro energy is available, so any secondary hydro energy can be used to displace thermal generation. A higher Thermal Displacement Market (TDM)[22] increases the amount of secondary hydro energy that is usable. This is important because the Treaty assumes that any secondary hydro energy that can be used for thermal displacement is just as valuable as firm hydro energy. In general, an increase in the TDM results in a disproportionate increase of usable secondary energy in the Step III system in

[20] The Treaty defines usable energy as the hydro energy in the critical period (also called firm energy), plus secondary hydro energy (also called non-firm energy) that can be used to displace thermal installations, and 40% of the remaining secondary energy.
[21] Canadian storage increases usable energy by augmenting low inflows, reducing spill, raising U.S. reservoir elevations, and storing unusable secondary energy for release when it is usable.
[22] In accordance with the 1988 Entity agreements on Principles and Procedures, Step I thermal installations, as the highest-cost marginal resource, are presumed to support all PNWA exports (system sales), with a few exceptions. So the Thermal Displacement Market is essentially the thermal installations that are needed to meet load in the PNWA minus the non-displaceable minimum thermal generation.

comparison to the Step II system. Consequently, the Entitlement energy, which is one-half of the difference between the Step II usable energy and the Step III usable energy, will decline as the TDM increases. As a result, the TDM is the primary factor affecting the Entitlement energy until secondary energy is fully utilized for displacing thermal in Steps II and III. When this occurs, the minimum Entitlement energy is reached, as discussed in section 3.3.5.2.

3.3.4.1. Calculation of Canadian Entitlement for 2024-25

The determination of the Thermal Displacement Market for 2024-25 is shown in Table 3-5.

Table 3-5 – Comparison of Thermal Displacement Market, in average annual MW

	Thermal Displacement Market	AOP14	AOPC25	AOPA1	AOPC25-AOP14	AOPA1-AOPC25
1	Coordinated Thermal Installations	10031	10853	10846	822	-7
2	Minimum Thermal Generation	226	248	248	22	0
3	System Sales	227	91	91	-136	0
4	Thermal Displacement Market [1/]	9578	10514	10507	936	-7
Notes: [1/] TDM = Coordinated Thermal - Min Thermal - System Sales						

Table 3-6 provides the computation of Canadian Entitlement for Studies C and A for the Joint Optimum Generation in Canada and the U.S. AOP14 is shown for comparison.

Table 3-6 – Canadian Entitlement for Studies A and C and Comparison with AOP14

1	Entitlement Capacity	AOP14	AOPC25	AOPA1	AOPC25-AOP14	AOPA1-AOPC25
a)	Step II CP Average Energy	8935	8929	8929	-6	0
b)	Step III CP Average Energy	6942	6956	6956	14	0
c)	Step I CP Average Load Factor	74.6%	74.7%	74.7%	0.1%	
d)	Capacity Benefit	2671	2641	2641	-30	0
e)	Capacity Limit [1/]	4328	4144	4144	-184	0
f)	**Capacity Entitlement [2/]**	**1336**	**1320**	**1320**	**-16**	**0**
2	**Entitlement Energy**					
a)	Step II firm energy	8898	8892	8892	-6	0
b)	Step II thermal displacement	2472	2543	2506	71	-37
c)	Step II other usable energy	56	30	35	-26	5
d)	Total Step II usable Energy	11425	11464	11432	39	-32
e)	Step III firm energy	6169	6200	6201	31	0
f)	Step III thermal displacement	3921	4070	4047	149	-23
g)	Step III other usable energy	326	255	251	-71	-4
h)	Total Step III usable Energy	10416	10526	10500	110	-26
i)	**Energy Entitlement [3/]**	**506**	**469**	**466**	**-37**	**-3**
Notes: [1/] Capacity Credit Limit uses method defined in Appendix A						
[2/] Entitlement Capacity = Lines ((1a - 1b) / 1c) / 2						
[3/] Entitlement Energy = Lines (2d -2h) / 2						

In comparing Study C with AOP14, the Canadian Entitlement energy was reduced by 37 aMW, due largely to an increase of 936 aMW in the Thermal Displacement Market. The difference in Canadian Entitlement energy between Study A and Study C was only 3 MW.

The Canadian Entitlement capacity at 1,320 MW was the same in both Study A and Study C, and 16 MW less than in AOP14. Between AOP14 and the 2024-25 studies there were offsetting effects from the decrease in average critical period load factor, which increased the Entitlement capacity, and changes in the average critical period Steps II and III energy capability, which decreased the Entitlement capacity.

3.3.4.2. Estimate of Canadian Entitlement in 2045

In order to assess changes in Canadian Entitlement with time, the Canadian Entitlement was estimated for Study C for the 2044-45 operating year using the Streamline Procedures. Only Study C was performed, since the difference between Study C and Study A was not expected to be significant for 2044-45. In the Streamline Procedures, the AOP Step I operating criteria and hydropower generation are assumed to be the same as in previous AOPs (in this case 2024-25). Therefore, the only studies that needed to be completed to calculate the Canadian Entitlement were the Steps II and III critical period and 30-year hydroregulation studies.

Table 3-7 compares the thermal installations and Thermal Displacement Market between AOPC25 and AOPC45.

Table 3-7 – Calculation of the Thermal Displacement Market

	Thermal Displacement Market	AOPC25	AOPC45	Difference
1	Coordinated Thermal Installations	10853	17776	6923
2	Minimum Thermal Generation	248	421	173
3	System Sales	91	0	-91
4	Thermal Displacement Market [1/]	10514	17355	6841

Notes: [1/] TDM = Coordinated Thermal - Minimum Thermal - System Sales

The change in the Study C 2045 Step II hydro load shape due to the increase in thermal installations, compared to 2025, caused a change in the length of the Step II critical period. Significant load reductions in September and October caused surpluses to occur in September and October 1943 that required adjusting the system to full contents in these periods. This changed the Step II critical period, which had been identical in all previous AOP/DDPB studies, and resulted in a 306 aMW increase in the critical period average energy because the September-October loads were lower than the critical period average. The Step III critical period was not unusually affected and remained the same as in previous AOP/DDPBs. The Step III critical period average energy was reduced by 28 aMW from AOPC25 to AOPC45. A summary of the critical period and critical period average energy is provided in Table 3-8.

Table 3-8 – Step II and III Critical Period Results

	Length (months)	Critical Period Start Date	Critical Period End Date
All previous Step II	20	Sep 1, 1943	Apr 30, 1945
All recent Step III*	5.5	Nov 1, 1936	Apr 15, 1937
Study C 2044/45 (Step II)	18	Nov 1, 1943	Apr 30, 1945
Study C 2044/45 (Step III)	5.5	Nov 1, 1936	Apr 15, 1937

*Since 2006

Table 3-9 shows a comparison between the AOPC45 and AOPC25 Canadian Entitlement. The Entitlement capacity increased from 1,320 MW for 2024-25 to 1,524 MW for 2044-45 due to the higher Step II average critical period generation. The slight increase in average critical period load factor from 74.73 to 75.71 percent reduced the Entitlement capacity. The Entitlement energy decreased from 469 aMW in 2024-25 to 290 aMW in 2044-45. The reduction is largely due to the 6,841 aMW increase in the Thermal Displacement Market.

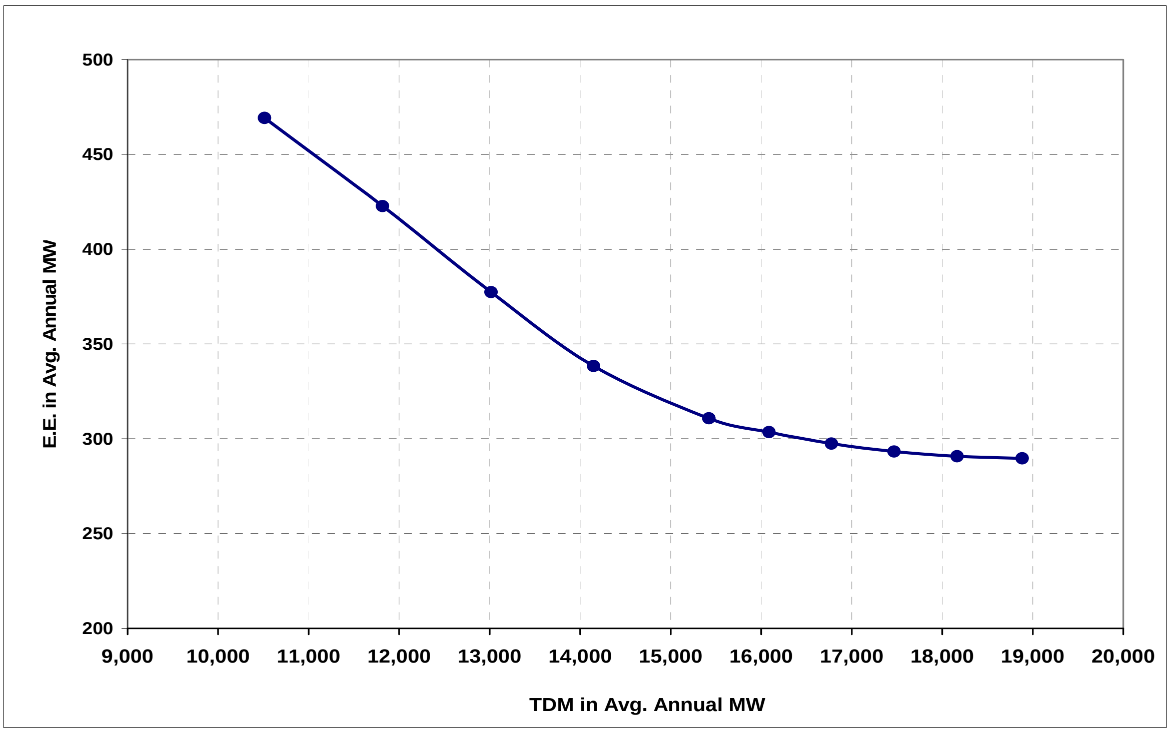
Table 3-9 – Calculation of 2044-45 Canadian Entitlement

1	**Entitlement Capacity**	**AOPC25**	**AOPC45**	**Difference**
a)	Step II CP Average Energy	8929	9235	306
b)	Step III CP Average Energy	6956	6928	-28
c)	Step I CP Average Load Factor	74.7%	75.7%	1.0%
d)	Capacity Benefit	2641	3047	406
e)	Entitlement Capacity Limit	2621	1995	-626
f)	**Entitlement Capacity** 1/	**1320**	**1524**	**204**
2	**Entitlement Energy**			
a)	Step II firm energy	8892	8854	-38
b)	Step II thermal displacement	2543	2633	90
c)	Step II other usable energy	30	0	-30
d)	Total Step II usable Energy	11464	11488	24
e)	Step III firm energy	6200	5925	-275
f)	Step III thermal displacement	4070	4983	913
g)	Step III other usable energy	255	0	-255
h)	Total Step III usable Energy	10526	10908	382
i)	**Entitlement Energy** 2/	**469**	**290**	**-179**
Notes: 1/ Entitlement Capacity = Lines ((1a - 1b) / 1c) / 2				
2/ Entitlement Energy = Lines (2d -2h) / 2				

The Entitlement energy estimates for 2044-45 are more speculative than those for the 2024-25 studies for many reasons, but primarily due to the uncertainty in the forecast of PNWA firm load, the load shape, and the mix of thermal/renewable resources needed to meet firm load. The Entitlement capacity is also speculative due to the potential to switch from an energy-critical system to a capacity-critical system, as discussed in section 3.3.5.2.

The 2044-45 study results indicate that the minimum Entitlement energy may be reached sometime before 2044-45. To estimate that effect, the fundamentals can be shown by looking at the 2024-25 studies. For the AOPC25 studies the 30-year average annual energy in the Step II study was 11,509 aMW and in the Step III study 10,908 aMW, a difference of 601 aMW. The maximum monthly secondary hydro energy in the Step II study was 11,700 aMW and in the Step III study about 15,500 aMW. With a TDM of 15,500 aMW, the difference in usable energy would be 601 aMW, and the Entitlement energy would be one-half that value at 300 aMW. The AOPC45 study shows an Entitlement of 290 aMW for the 2044-45 operating year, which is lower than the AOPC25 would suggest, because the TDM is not the only factor determining the amount. As the thermal resources increase, the Steps II and III load shapes change, thus changing the 30-year average energy. The relationship between TDM and the Canadian Entitlement energy for AOPC25 is shown in Figure 3-10.

Figure 3-10 - Entitlement Energy vs. Thermal Displacement Market



At some point in the future, the TDM is expected to grow as large as the highest surplus energy in the Step III 30-year hydroregulation study; thus, any increase in the TDM above 15,000 aMW will have only a small effect on the Entitlement energy due to the changes in hydro load shape.

The April 1994 "Forecast of Canadian Entitlement to Downstream Power Benefits, Entitlement Forecast Studies" estimated the minimum Entitlement energy at 260 MW and the Entitlement capacity for 2023-24 between 1,198 MW and 1,434 MW. The differences between the Phase 1 study results and the 1994 forecast were not analyzed but likely are due to a number of differences in assumptions, including load shape, thermal maintenance, installed hydro capacity, non-power constraints, and irrigation requirements.

3.3.5. Uncertainty and Factors Affecting the AOP and Canadian Entitlement

There are many complex and interrelated factors that affect the AOP and DDPB. In general, all of the factors affecting the AOP also affect the DDPB, but some are more important and have a much larger impact on the DDPB than on the AOP. Other factors have no impact on the AOP but do affect the DDPB.

The most significant factors are generally the same as those identified in the 1960s when the Treaty was negotiated. It was recognized that increased generating capability at U.S. dams, new reservoirs in the PNWA, increased irrigation depletions, increased thermal installations, and increased electrical intertie capability between the PNWA and California could have a significant effect on Canadian storage operation and the downstream power benefits. The procedures in the Treaty for the AOP and calculation of the DDPB allow some of these changes and limit others to create a balance of expected benefits. Today, there are many new issues and factors that may affect the AOP and DDPB, and others may arise in the future. The most significant are discussed below.

3.3.5.1. AOP

The AOP operating criteria for Canadian storage are affected mainly by changes to the Residual Hydro Load shape. The average annual hydro load is essentially fixed by the amount of water available in the critical period and the operating policy and constraints. The Residual Hydro Load shape can vary considerably, however, and that affects how the water is stored and released throughout the year. The Residual Hydro Load shape is affected by many factors, including the shape of regional loads; exports; imports; generation pattern of other resources, especially thermal maintenance and plant factors; and changes to non-power requirements and installed capacity at non-Base System projects.

If the PNWA firm load shape were to stay the same in the future, and added thermal and other resources had a flat annual capability, then the Residual Hydro Load would become larger in the winter and smaller in the summer. That was the expectation in the 1960s, but it appears unlikely now. Summer loads are growing faster than winter loads, and much of the resources are either purchased or operated as needed to meet seasonal needs, including seasonal exchanges.

The amount of Residual Hydro Load has varied little in recent AOP studies. Looking at past AOPs, there have been some significant changes in seasonal exchanges with California (matching import/exports) and thermal maintenance schedules that have been big enough to change the Residual Hydro Load shape. In general, higher hydro load in some months will result in higher Canadian outflows in those months to help meet that load.

The AOP operating criteria could also be changed dramatically as the system switches from an energy-constrained to a capacity-constrained system, depending on the optimization goals at that time. This switch could result in different operating policies that may attempt to maximize FELCC, Firm Power Load Carrying Capability (FPLCC), average energy, or certain flows and reservoir elevations.

3.3.5.2. DDPB

The Entitlement energy is affected primarily by the Thermal Displacement Market, which is affected by the future mix of thermal/renewable resources, PNWA load growth, and load shape. Uncertainty in the forecasts of these parameters affects the projected Entitlement energy. At some point in the future, the TDM is expected to grow as large as the highest surplus energy in the Step III 30-year hydroregulation study, and any further increase will have no effect on the Entitlement energy. The Canadian Entitlement energy will be mainly derived from spill reductions and head gain at U.S. projects, due to operation of Canadian Treaty Storage. At that point, Canada is required to operate only the amount of Canadian storage needed to provide that level of regulation, and that could be less than the full 15.5 Maf defined in the Treaty.

The Entitlement capacity is affected by the changes in length of the Steps II and III critical period and the average Step I critical period load factor. The length of the Steps II and III critical period is affected mainly by the load shape, the shape of the thermal resource generation, and changes to non-power constraints, including flood control. The Step I critical period has not changed significantly (varies between 42 and 42.5 months) since the early 1970s.

Switching from an energy-constrained to a capacity-constrained system is affected by all factors that affect the Canadian Entitlement capacity. This includes average critical period load factor, peak reserves (which may be affected by the thermal/renewable resource mix), and changes to the critical period. The more non-displaceable resources are added to the system, the higher the chance that the system will move from an energy-critical system to a capacity-critical system. As capacity becomes critical in Step I, non-baseload resources may potentially be considered to be used to meet the capacity need. However, if capacity becomes critical in Step II, the Capacity Credit Limitation (CCL; see section 3.3.5.3 and Appendix A) may become an issue.

The Phase 1 studies forecast the Canadian Entitlement capacity to be increased from around 1,300 MW in 2024-25 to around 1,500 MW in 2044-45 due to a shorter Step II critical period. The amount of thermal installation has significantly reduced September and October hydro loads of both Steps II and III and causes the Step II Critical Period to start at November instead of September. The use of significant amounts of non-displaceable and variable wind resources may require a higher level of peak reserves and hence could increase the probability of a capacity-critical system in any or all three Steps. That is why the Canadian Entitlement capacity will be very volatile and unpredictable.

The Canadian Entitlement capacity is especially sensitive to the Residual Hydro Load shape of Step II and III systems, because the start and end dates for the critical period can be affected. The total PNWA firm load is not used in the DDPB; instead, only the PNWA firm load shape is used. The Residual Hydro Load for the Steps II and III systems is created for each study by adding the critical period hydro capability to the thermal installation capability to create a total firm load that is then shaped the same as the PNWA firm load. Thus, the PNWA firm load shape and thermal installation amount and shape are the only factors affecting the hydro load shapes for the Steps II and III studies.

3.3.5.3. Capacity Credit Limitation

The CCL is defined in the Treaty and clarified in Protocol section IX. In general, it sets a limit on the maximum amount of Entitlement capacity. The Capacity Credit Limit has not limited any Entitlement capacity to date but may in the future.

Although the CCL did not apply in the Phase 1 studies, it could apply by 2024 or sooner, depending on the requirements for peak reserves and possibly different methods for calculating peak load capability. The CCL is described in Appendix A.

3.4. FLOOD CONTROL OPERATIONS: STUDIES A AND B

A primary goal of the Phase 1 studies has been to assist in understanding Called Upon flood control operations after 2024. The Treaty describes Called Upon flood control in general terms. In addition, the Treaty Protocol describes the consultation process to be used by the Entities for Called Upon use of flood control storage in Canadian projects. However, neither the Treaty nor the Protocol contains sufficient details and procedures to fully guide the Entities in real-time implementation of Called Upon operations. The Phase 1 studies are the Entities' first attempt to identify the uncertainties associated with implementation of Called Upon flood control after 2024.

3.4.1. OVERVIEW OF CALLED UPON FLOOD CONTROL OPERATIONS AFTER 2024

Treaty flood control operations under the FCOP prior to 2024 are summarized in section 1.2.1 and described in detail in Appendix A. The current operations provide a baseline to compare the study methodologies applied in the Phase 1 technical studies. However, the focus of the Phase 1 studies is on one possible approach to implement Called Upon flood control operations. The Treaty states that after 2024 the U.S. can call upon Canada to operate storage to control potential floods in the U.S. that could not be adequately controlled by all the related storage facilities in the U.S. Called Upon flood control operation begins when the operation of Canadian reservoirs to provide additional storage volumes or to reduce outflows determined to meet U.S. needs is initiated. Once the operation begins, the Entities will need to begin calculating Canadian operating costs and economic losses associated with the Called Upon action[23] so the U.S. can reimburse Canada. Prior to making the formal Called Upon request, Canadian and U.S. system operators will need to conduct short-term and real-time planning studies to determine if Called Upon operations will be required and to determine volumes of Canadian storage needed to control flooding downstream in the U.S. The Phase 1 study scenarios, particularly those conducted in forecast mode, attempted to simulate what those methodologies and procedures might entail post-2024 without any consideration of the consultation process.

[23] Methodologies and procedures to calculate operating costs and economic loss to Canada associated with Called Upon flood control operations are not defined by the Treaty or Protocol, and no attempt was made in the Phase 1 studies to develop those procedures or to estimate Canadian costs and losses of the Phase 1 scenarios. However, Phase 1 studies quantified the potential difference in Canadian storage reservoir operations that this preliminary Called Upon operation caused.

Throughout this document, the following terminology is used to describe Called Upon flood control operations:

- A *threshold* is a forecast volume of runoff for the Columbia River system for the April through August period that may lead to potential flood levels that cannot be adequately controlled by U.S. facilities. The threshold volume varies for each month from January through April. If a runoff volume forecast for a given month exceeds the threshold for the corresponding month, a calculation to determine the required Canadian Called Upon flood control drafts is triggered.
- *Called Upon flood control drafts* are calculated drafts from Canadian projects to meet U.S. flood control needs and are based on the assumptions used in the various Phase 1 studies. Note that at this point only the calculation of Called Upon draft requirements is triggered; there is no formal procedural request to Canada for change in reservoir operations to meet Called Upon requirements. However, in the Phase 1 modeling, the U.S reservoirs were drafted for effective use of flood control storage in all triggered periods.
- *Called Upon action.* In cases where the Called Upon flood control draft is less than the power drafts, then Canadian reservoirs would operate to the power draft, and this is not considered a Called Upon action. Called Upon actions would occur only in cases where Called Upon flood control draft is deeper than the anticipated power draft. In the Phase 1 modeling, any day that the Called Upon flood control draft was deeper than the power draft was considered a Called Upon action.
- *Called Upon year.* A Called Upon year is any year in which there is at least one month in which the runoff volume forecast exceeded the threshold and operation at any Canadian Treaty project is changed to meet U.S. flood control needs under a Called Upon action.

3.4.2. CALLED UPON FLOOD CONTROL ASSUMPTIONS

A number of assumptions pertaining to flood control operations that went into defining the various scenarios considered under the three Phase 1 studies are described in section 2.1. A number of additional assumptions made to model flood control and Called Upon operations in the Phase 1 studies are described below.

Process for Requesting Called Upon. The Called Upon operation was assumed to be assured and immediate. Modeling in the Phase 1 study did not consider time that may be needed to follow a consultation process outlined in the Treaty Protocol where the U.S. would request Called Upon storage from Canada and Canada could take up to 10 days to consider the request before responding. If the Entities do not agree on the call or its terms the matter is then submitted to the Permanent Engineering Board.[24] The total time between requesting and starting the implementation of Called Upon action could be up to 20 days. For the purpose of modeling Phase 1 scenarios, no attempt was made to emulate the request/consultation process. For study

[24] The Columbia River Treaty established the Permanent Engineering Board (PEB) to handle tasks such as assembling flow records, assisting in settling differences that may arise between the Entities, and creating annual reports of the results being achieved.

purposes only, it was assumed that if Called Upon storage was needed based on the calculated flood control draft, then the requirement was met automatically.

Effective Use of U.S. Flood Control Storage Space. For the Phase 1 studies, an initial attempt was made to define how the U.S. system could be effectively used to control flood events. The U.S. headwater projects (Libby, Dworshak, and Hungry Horse) were assumed to be operated to the effective use procedure. In demonstrating the effective use, the projects were drafted to at least the extent necessary to ensure that the projects could be operated at minimum flows during the peak flow period. Grand Coulee and Brownlee were drafted toward empty. It is possible that other projects may also be able to provide some degree of flood protection, but this possibility was not investigated in Phase 1.

Assured Operation from Canada. If the Treaty is terminated after 2024 there will no longer be coordinated planning between Canada and the U.S. through the FCOP or AOP. In that case, Canadian operations from year to year will be highly uncertain. The power drafts developed for the Phase 1 studies were treated as an assured operation, although in reality there would be no assurance that the projects would be operated in this manner if the Treaty were terminated. It should be noted that the operations for the B1 and B2 studies are monthly estimates of potential operations. The variation of the day-to-day operation may be significant, as the Canadian system will be able to fully respond to market conditions and B.C. power and non-power needs without having AOP limitations.

Variable Flow Flood Control. Variable Flow (or VarQ) refers to a system flood control operation developed by the Corps for Libby and by Reclamation for Hungry Horse as an alternative to standard flood control operations. In general, the intent of VarQ flood control is to improve the likelihood of refill and potentially provide more instream flow for fisheries during and after the refill season. For this reason, VarQ procedures generally can result in higher reservoir elevations at Libby and Hungry Horse and higher corresponding spring outflows than standard flood control procedures. VarQ flood control influences operations for system flood control at Grand Coulee Dam and can cause it to draft deeper than it otherwise would.

All of the Phase 1 studies modeled Hungry Horse using VarQ operations. However, because Libby VarQ is not used in Treaty studies, Libby was operated to Standard flood control in the studies where the Treaty continues (Studies A and C). Libby VarQ flood control was used only in the B studies. In Called Upon years, the reservoir was drafted to the deeper of its effective use space or the relevant (VarQ or Standard) Storage Reservation Diagram (SRD).

Kootenay Lake IJC. These studies were conducted in compliance with the 1938 International Joint Commission (IJC) Order for Kootenay Lake (for details regarding the IJC order, see Appendix A, section A.2.4.5).

3.4.3. Called Upon Flood Control Modeling Methodology

The Treaty does not specify how Called Upon flood control operations would be implemented post-2024. However, Appendix A of the FCOP describes a general approach for using On-Call flood control prior to 2024. For the Phase 1 studies, the Called Upon procedure was assumed to follow a similar approach.

There were some adjustments to the Called Upon methodology as the studies progressed, based on lessons learned, so the initial methodology was refined as the studies progressed. Differences between studies are highlighted in the sections below.

3.4.3.1. Drawdown Period (generally January through April 15)

During the drawdown period, the water supply volume forecast[25] was assumed to be known on the first day of each month. If the volume forecasts throughout the drawdown period were less than a certain threshold,[26] then Called Upon was not required for that year. However, if the volume forecast exceeded the threshold in at least one month, then the calculation to determine the required Canadian Called Upon draft was performed. This calculation assumed that the Canadian reservoirs would begin to draft on the first day of that month toward their end-of-month Called Upon draft objectives.[27] In the U.S., the headwater projects (Libby, Dworshak and Hungry Horse) were assumed to be drafted toward their effective use amount,[28] while Grand Coulee and Brownlee were drafted toward empty by April 30.

If a subsequent water supply forecast dropped back below the threshold, then it was assumed that the U.S. reservoirs would pass inflows until the calculated drafts intersected with the SRD draft. For the Canadian reservoirs, the A1 and B1 studies assumed that the Canadian projects would pass inflows until the reservoir elevations intersected with the power or local flood control levels. The B2 study assumed that the Canadian projects would release minimum flows until the reservoir recovered to the power operation levels.

If the calculated Canadian Called Upon draft was deeper than the power draft on any day,[29] then calculated Called Upon operations were implemented and the year was considered to be a Called Upon year. For the Phase 1 studies, this Called Upon action was assumed to be assured and immediate.

[25] For the Phase 1 studies, synthetic volume forecasts were developed using historical meteorological data with current procedures (to the extent possible).

[26] The threshold volume represents the maximum runoff volume to which the U.S. projects alone are able to control flows below the flow objective. To account for forecast uncertainty, threshold volumes included a reduction equivalent to one standard deviation of the forecast errors for each month.

[27] For Studies A1 and B1, the Canadian Called Upon draft objectives were based on the On-Call SRDs from the FCOP for Arrow, Mica, and Duncan, except that the Arrow On-Call SRD was modified to provide a variable draft between 3.6 and 7.1 MAF depending on the forecast at The Dalles. For Study B2, the Canadian Called Upon draft was based on the modified Arrow On-Call SRD only. The procedure for Study B2 was changed based on the results from Study A1, which indicated that the power drafts at Mica and Duncan were likely sufficient so that additional Called Upon storage from Mica and Duncan would not be required.

[28] The effective use amount was determined based on the greater of (1) the space required on April 30 for the project to fill on June 30 (as determined using the volume forecast and while releasing minimum flow during May and June) and (2) the project's SRD draft.

[29] Daily drafts were calculated using straight-line interpolation between month-end storage objectives.

3.4.3.2. Refill Period (generally April 16 through July)

Refilling of flood control projects is an important part of system power studies to ensure that reservoirs have the maximum amount of water in storage to begin the next operating year. If projects are not refilled yearly, the ability to meet future system firm load is reduced; therefore, refill of all projects was a priority after meeting flood control needs. Refill is also important for meeting other operating objectives that were not considered in the Phase 1 studies, such as fisheries and recreation.

During the refill period, reservoirs begin to refill based on the timing of the Initial Controlled Flow using the procedures described in the FCOP. The U.S. headwater projects, having been drafted for effective use, would release minimum flows during the refill period. Grand Coulee would operate to meet the ICF at The Dalles. The Canadian projects would generally refill while releasing minimum flows until recovering to the power operation levels. After the peak unregulated flow at The Dalles had passed and streamflow had receded, the headwater projects continued to release minimum flow to fill or might release more than minimum flow to prevent projects from filling too rapidly, resulting in the need to pass inflow at a high rate in the future.

3.4.4. Results of Post-2024 Called Upon Flood Control Operations

This section summarizes the key findings and results of the Phase 1 studies, including comparing Called Upon operations across the scenarios. The emphasis is on interpreting the effects of the various assumptions made with regard to implementation of Called Upon flood control.

3.4.4.1. Frequency and Duration of Called Upon Operations

An objective of the Phase 1 studies was to determine the approximate frequency that the U.S. might need to call upon Canada for flood control storage after 2024 and the relative duration of Called Upon operations. The maximum flood flow objective at The Dalles was the strongest determinant of the frequency of Called Upon flood control operations. The runoff volume forecast ultimately determined the frequency Called Upon was triggered over a multi-year period. The studies confirmed what may have been considered an obvious assumption going into Phase 1: the higher the maximum flow objective in the U.S., the less frequently Called Upon operations in Canada will be required.

As shown in Table 3-10, every scenario with 600 kcfs as the maximum flow objective triggered Called Upon operation in 21 years (30%) out of the 70-year period of record evaluated. For every scenario in which 450 kcfs was the maximum flow objective, Called Upon was triggered in 52 years (74%). This result occurred regardless of whether the Treaty continued (A Studies) or was terminated (B Studies), because the assumptions to trigger the Called Upon calculation were the same. Called Upon action from Canada was required in all years when the Called Upon calculation was triggered. In years when Called Upon was not triggered (flood control storage space in the U.S. was presumed to be adequate to control floods to the maximum flow objective at The Dalles without additional Called Upon storage in Canada), all U.S. reservoirs operated in accordance with existing procedures. There was no significant difference in system flood control operations from study to study in non-Called Upon years, so they are not discussed as part of the results in this section.

Table 3-10 – Summary of Called Upon Frequency, Peak Flows and Volumes

		Drawdown Period (Jan-Apr 15)			Refill Period (Apr 16-Jun)				
Scenario	# of Years Triggered by Volume Forecast	# of Years Objective Exceeded	The Dalles Peak (kcfs)	Year of Peak	# of Years Objective Exceeded	The Dalles Peak (kcfs)	Year of Peak	Total Canadian Called Upon Storage Required (Maf)	Year of Maximum Requirement
A1F600	21	0	539	1974	1	669	1948*	2.3	1974
B1F600	21	0	557	1982	1	714	1948	15	1976
B2F600	21	0	547	1982	1	674	1948	6.4	1972
*A1F600***						*574*	1997		
*B1F600***						*519*	1997		
*B2F600***						*513*	1997		
A1F450	52	2	539	1974	7	585	1974	3.2	1958
B1F450	52	5	504	1974	5	581	1948	15	1934
B2F450	52	2	517	1974	5	554	1948	6.2	1956

*Water year 1948 did not trigger as a Called Upon year due to a very inaccurate water supply forecast; the actual total volume runoff greatly exceeded the forecast amount

** Peak flows in the Called Upon years are italicized for A1F600, B1F600 and B2F600

Table 3-11 provides additional details with respect to the potential frequency and duration of Called Upon operations by comparing the number of days that the U.S. would request Called Upon flood control from Canadian reservoirs. In Table 3-11, “planned draft” is the operation of Canadian reservoirs for power and/or flood control if the U.S. had not Called Upon flood storage. The number of days Called Upon flood control exceeded the planned draft of Canadian reservoirs is shown. As expected, Called Upon duration would be longer in the scenarios in which the Treaty is terminated and Canada operates principally for local flood control (B1) than in the scenarios where the Treaty continues (A1) or the Treaty is terminated and Canada operates principally for power operation (B2). This is because deeper seasonal power drafts in the latter two sets of scenarios provide incidental flood storage benefits. In the B2 study, assumptions were made to use only Arrow for Called Upon flood control, because Mica and Duncan were already drafted deeply for power, precluding the need for additional space requests at Mica and Duncan. A similar assumption could have been made in Study A1, which would likely preclude the need for additional space from Mica and Duncan.

Table 3-11 – Average Number of Days Called Upon Draft is Greater than the Planned Draft at Canadian Reservoirs

Average Number of Days Called Upon Draft is Greater than Power Draft or Canadian Local Flood Control during January through June in Called Upon Years				
		Mica	Arrow	Duncan
A1F600	Min	0	0	10
	Max	140	119	176
	Avg	47	37	135
B1F600	Min	111	80	91
	Max	182	182	182
	Avg	166	156	166
B2F600	Min	0	56	0
	Max	0	182	0
	Avg	0	128	0
A1F450	Min	0	0	85
	Max	151	123	181
	Avg	46	33	149
B1F450	Min	142	133	150
	Max	182	182	182
	Avg	177	167	179
B2F450	Min	0	56	0
	Max	0	182	0
	Avg	0	151	0

It is important to note that these results reflect the Phase 1 study assumptions and methodologies. However, the results may overstate the number of years that Called Upon operations would be required to meet U.S. flood control needs in actual operation. This is especially the case with the frequency that Duncan is Called Upon in all studies and the frequency that Mica is Called Upon in Study A1. In the A1F450 study Duncan was used for Called Upon Flood control in all 52 years that Called Upon was triggered. Arrow and Mica Called Upon drafts were used in 14 years and 15 years, respectively. When Called Upon was triggered and the call was made, Duncan drafted to the Called Upon draft from the FCOP. The Duncan Called Upon draft required Duncan to draft 1.4 Maf by February 28, while the full Mica and Arrow Called Upon draft did not occur until March 31. This early draft for Duncan increases the number of days that Duncan is in a Called Upon situation and might imply that Duncan was overused in the studies. In actual operations it is likely that the use of Duncan would not have occurred in the years that Mica and Arrow were not Called Upon for flood control.

3.4.4.2. Volume of Canadian Called Upon Storage

Another important objective of the Phase 1 studies was to identify the volume of Called Upon storage in Canadian reservoirs needed to meet U.S. flood control needs after 2024, based on certain assumptions. Table 3-12 summarizes the average Called Upon volume required under the different scenarios for Called Upon years and the maximum Called Upon storage volumes required. Note that these volumes do not represent the total volume of Canadian storage required to control flood events downstream in the U.S. Rather, they represent the additional increment of Called Upon storage over and above the local flood control or power drafts under the planned operation of Canadian reservoirs if Called Upon storage was not required. Figure 3-11 and Figure 3-12 show the Called Upon storage required from Canadian reservoirs for Called Upon Years in the 600 and 450 kcfs maximum objective scenarios, respectively.

Table 3-12 – Called Upon Storage Volumes (Maf) Required from Canadian Projects

	Treaty Continues (A1)	**Treaty is Terminated (CND Power draft) (B2)**	**Treaty is Terminated (CND local draft) (B1)**
600 kcfs objective			
Average over 21 Called Upon years	1.3	4.7	10.7
Maximum (year)	2.3 (1974)	6.4 (1972)	15 (1976)
450 kcfs objective			
Average over 52 Called Upon years	1.5	4.7	11.4
Maximum (year)	3.4 (1958)	6.2 (1956)	15 (1943)

As expected, the volume of Called Upon storage will generally be less if the Treaty continues after 2024. This result is attributable to the understanding that the Treaty projects would continue to be operated in coordinated fashion by Canada and the U.S. to optimize hydropower under an annual AOP with assured power drafts that would provide incidental flood control benefits. The largest expected volumes of Called Upon storage were under the B1 scenarios, in which the Treaty is terminated and Canada operates principally for local flood control, drafting Arrow only 2 feet in most years. The B2 studies, in which the Treaty is terminated, also provided an assumed power draft, although it is not assured, so the Called Upon volume was less than expected when compared to the B1 scenarios. Composite Called Upon drafts were similar between the 600 kcfs and 450 kcfs studies, because the Called Upon volume drafted for flood control was the same once Called Upon was triggered. As discussed below, this should be improved for any further studies.

This finding demonstrates that the volume of storage requested by the U.S. for Called Upon varied significantly depending on whether the Treaty continues or is terminated. Under the Treaty is Terminated assumption, there was a wide range of volume of storage that may be required for Called Upon, depending on how the Canadian storage was operated.

For future implementation of Called Upon operations, it will be important for Canada and the U.S. to agree on the base condition against which Called Upon operations will be measured, as this will influence the accounting for Called Upon volumes. Under the Treaty, after 2024, the

U.S. will be required to reimburse Canada for operating costs and economic losses associated with Called Upon operations. No attempt was made to calculate the economic losses associated with Called Upon operations under the Phase 1 scenarios.

3.4.4.3. Effects on Peak Flows

No attempt was made to calculate potential flood damages in the U.S. or Canada resulting from the Phase 1 scenarios. For the purposes of Phase 1, peak flows at The Dalles were used as a proxy for levels of flood control provided. The following paragraphs compare the relative effects of the Phase 1 scenarios on peak flows at The Dalles.

When the Called Upon operation was triggered, the Canadian and U.S. reservoirs were all drafted to the same volume, regardless of maximum flow objective, closely following the existing SRDs defined in the FCOP, and the regulation in the spring is similar. As a result, the peak flows were similar. Table 3-13 compares peak flows at The Dalles under the A and B studies that were conducted in forecast mode. As seen in Table 3-13, the average difference between the 450 kcfs and 600 kcfs maximum flow objectives studies was less than 20 kcfs. This finding indicates the need to investigate alternative draft calculations or procedures for different flow objectives in future studies.

Table 3-13 – Comparison of Peak Flows at The Dalles

The Dalles Flows (kcfs)				
Scenario	**Average Peak in 21 Called Upon Years**	**Average Peak in 52 Called Upon Years**	**Average Peak in Non-Called Upon Years**	**70-Year Peak Average**
A1F600	437		363	386
A1F450	432*	389	314	370
B1F600	413		413	413
B1F450	394*	367	363	366
B2F600	407		363	376
B2F450	391*	361	316	349

*The 600 kcfs objective triggered Called Upon in 21 years
The 450 kcfs objective triggered Called Upon in 52 years
To compare the effect of 450 kcfs vs. 600 kcfs, the peak flows at The Dalles for the same 21 years triggered by the 600 kcfs objective were averaged.

Figure 3-11 – Composite Called Upon Draft Minus Power or Canadian Local Flood Control Drafts for Forecast 600 kcfs Studies

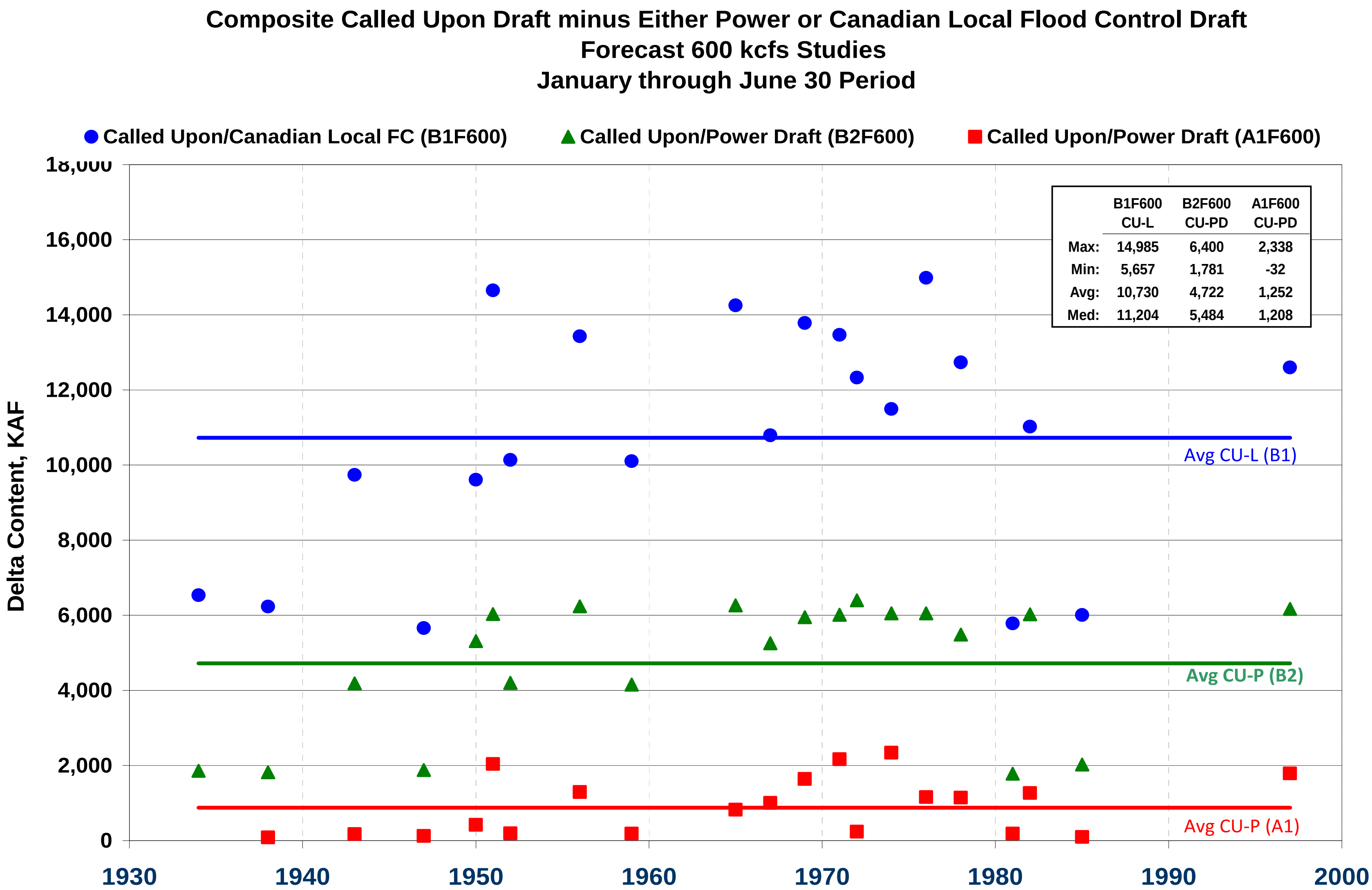
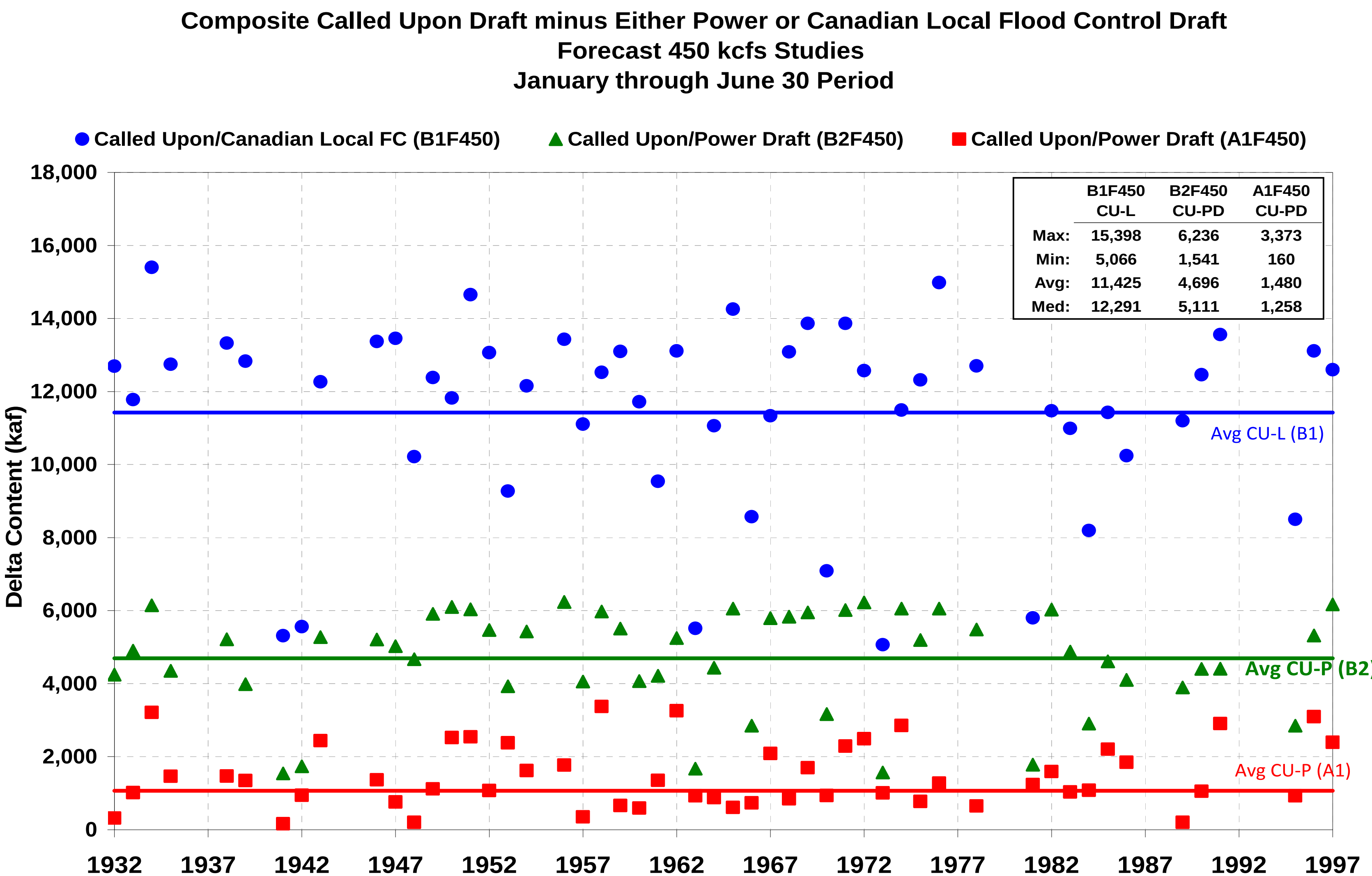


Figure 3-12 – Composite Called Upon Draft Minus Power or Canadian Local Flood Control Drafts for Forecast 450 kcfs Studies

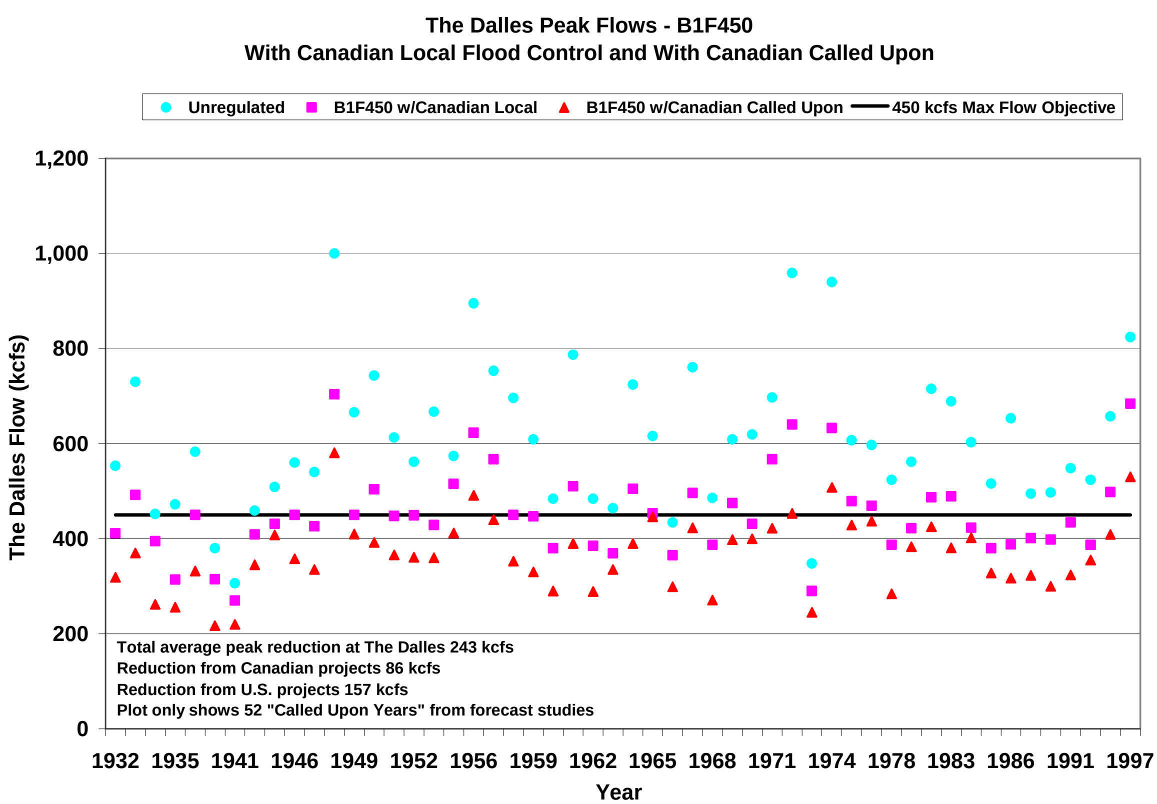


In the scenarios with a maximum flow objective of 600 kcfs (B1, B2, A1), there was only one year where the flow objective was exceeded, and that was not a Called Upon triggered year (in 1948 the forecast was substantially under-forecasted, and therefore Called Upon did not trigger). The regulated peak flow in this year was similar in the two power studies (A1 and B2), at about 670 kcfs. The regulated peak flow in the B1 study that used Canadian local flood control was 714 kcfs. The studies that included power drafts reduced the peak flow by about 44 kcfs in this non-triggered year.

3.4.4.4. Flow Reduction at The Dalles due to U.S. Projects and Canadian Projects

The B1F450 study was used to determine how much U.S. projects could reduce flows at The Dalles. Figure 3-13 shows reductions in peak flows at The Dalles for the 52 Called Upon Years by operation of the U.S. projects when Canadian projects were operating on local flood control. The figure also shows how the U.S. projects operating with the Canadian projects on Called Upon flood control further reduced flow at The Dalles. U.S. projects and Canadian local flood control reduced unregulated flows by an average of 243 kcfs, which is the difference between the "Unregulated" points and the "B1F450 Can Local" points in Figure 3-13. The minimum reduction was 36 kcfs and the maximum reduction was 319 kcfs. Canadian Called Upon operations reduced the flow 86 kcfs on average, with a minimum of 7 kcfs and a maximum of 187 kcfs. This is the difference between the "B1F450 Can Local" points and the "B1F450 Can CU" points.

Figure 3-13 – Comparison of Unregulated Peak Flows to Peak Flows for B1F450 Scenarios



3.4.4.5. Impacts on Use of U.S. Reservoir Storage

During initial operations for flood protection in the Phase 1 studies, before Called Upon operations were initiated U.S. reservoirs were operated to their SRDs. When a Called Upon operation was triggered, in order to make effective use of U.S. flood control storage Libby, Hungry Horse, and Dworshak reservoirs were drafted in the final Called Upon regulation to the deeper of their SRD or effective use space. In Called Upon operations Grand Coulee and Brownlee reservoirs were drafted toward empty. This effective space draft allowed the U.S. projects to draft and then refill on minimum flow, so the U.S. reservoir contribution of flow at The Dalles was the minimum possible, thus making effective use of space. This was required to demonstrate effective use even though Called Upon may not have been needed if Canadian power draft was deeper than the required Called Upon draft.

This concept of operating the U.S projects to effective use versus standard SRDs is new. To determine the impact on storage at the U.S. projects, the additional draft required for the effective use operation was examined for the 52 Called Upon years from the F450 kcfs studies. In non-Called Upon years, there was no effective use requirement, and the U.S. projects were operated to the existing SRDs for the individual projects. As may be expected, the U.S. projects were drafted significantly deeper during years that Called Upon operations were triggered, and the number of years that the projects did not refill also increased.

Tables 3-14 to 3-18 show the values for the F450 kcfs scenarios. The total draft requirements were similar for Study A and Study B in the F450 and F600 kcfs scenarios, so only one data set is provided.

The effects on Libby when using effective space versus both Standard SRD and VarQ are shown in Table 3-14. Compared with VarQ operation, in years when Called Upon was triggered, Libby drafted on average an additional 47.2 feet on April 30. In three of the Called Upon years, Libby also did not refill, due to forecast error. When using effective space versus Standard SRDs, Libby drafted on average an additional 10.8 feet on April 30.

Table 3-14 – Libby

VarQ minus Effective Space, difference in feet				
	Jan	**Feb**	**Mar**	**Apr**
Average	8.5	16.4	28.5	47.2
Median	3.4	5.9	28.3	53.6
Max	27.7	49.7	68.4	79.9
Min	0.0	0.0	0.0	0.0
Standard minus Effective Space, difference in feet				
	Jan	**Feb**	**Mar**	**Apr**
Average	1.0	1.7	4.8	10.8
Median	0.0	0.0	0.0	0.0
Max	12.2	23.1	36.4	46.6
Min	0.0	0.0	0.0	0.0

As shown on Table 3-15, Hungry Horse drafted on average an additional 45.1 feet on April 30 using effective space versus VarQ in years when Called Upon was triggered. In six of the Called Upon years, Hungry Horse did not refill, due to forecast error.

Table 3-15 – Hungry Horse

VarQ minus Effective Space, difference in feet				
	Jan	**Feb**	**Mar**	**Apr 30**
Average	11.0	20.4	30.6	45.1
Median	11.7	23.1	35.6	48.1
Max	14.1	29.5	44.4	55.4
Min	3.1	4.4	0.0	27.6

Table 3-16 shows that Dworshak drafts on average an additional 27.1 feet on April 30 when using effective space versus Standard SRDs. In seven of the Called Upon years, Dworshak did not refill, due to forecast error.

Table 3-16 – Dworshak

Standard minus Effective Space, difference in feet				
	Jan	**Feb**	**Mar**	**Apr 30**
Average	4.6	11.8	25.3	27.1
Median	0.0	8.1	22.3	1.2
Max	17.9	37.9	64.8	74.6
Min	0.0	0.0	0.0	0.0

Brownlee (Table 3-17) drafts on average an additional 31.4 feet on April 30 when using effective space versus Standard SRDs. Brownlee refilled in all Called Upon years.

Table 3-17 – Brownlee

Standard minus Effective Space, difference in feet				
	Jan	**Feb**	**Mar**	**Apr**
Average	0.1	0.7	14.3	31.4
Median	0.0	0.0	15.3	30.0
Max	5.4	8.7	47.6	97.8
Min	0.0	0.0	0.0	0.0

In Called-Upon years, Grand Coulee was drafted to empty, elevation 1208 feet, on April 30 when the Called Upon calculation was triggered in April. A comparison was made for the F450 studies between Grand Coulee drafting based on current procedures (Canadian project and Libby drafts were based on the FCOP; other U.S. projects were based on current SRDs; and no power drafts) and operating in Called Upon years. On average, Grand Coulee was drafted from 9.3 to 12.4 feet deeper than in current operations on April 30. The negative values in the table below indicate an early start of refill, before April 30. The average additional draft at Grand Coulee for

Called Upon years occurred when refill started May 1 or later, and Grand Coulee was drafted on average 14.4 to 18.3 feet deeper than current procedures. The project refilled every year but was also drafted empty an additional 24 to 26 years (depending on scenario) over the current operations.

Table 3-18 – Grand Coulee

April 30 difference in draft (SRD minus effective use; feet)						
All Called Upon Years				**Called Upon Years in which Refill Began after May 1**		
	A1F450	B1F450	B2F450	A1F450	B1F450	B2F450
Ave	9.3	12.4	12.2	14.4	17.8	18.3
Med	11.4	12.2	12.2	12.2	18.0	20.4
Max	31.1	31.1	32.8	31.1	31.1	32.8
Min	-25.6	-24.6	-27.1	1.5	4.0	1.5
Number of years GCL is empty on April 30th						
Base	A1F450	B1F450	B2F450			
4	29	30	28			

3.4.4.6. Called Upon Operations and Flex Operations

In the A1 scenarios, where the Treaty continues after 2024, Canada may flex operations between Arrow and Mica (shift storage of water between reservoirs) subject to maintaining the combined Arrow and Duncan outflows and meeting Flood Control requirements at each project. A cursory evaluation was conducted on a selected number of years to determine if it was physically possible to switch from a projected Flex operation to the Called Upon draft requirements and how long it would take to return to the Flex operation after Called Upon was no longer required.

The Flex operation at Arrow usually had Arrow 1 to 3 Maf higher than the Called Upon draft required. The assumption used to transition Arrow from the Flex operation to the Called Upon operation was to increase Arrow outflow up to approximately 65 kcfs.

The Flex operation at Mica normally had the project 1 to 3 Maf lower than the Called Upon operation. The assumption used to transition Mica to the Called Upon operation was to reduce outflows at Mica to minimum flow until the Flex operation intersected the Called Upon operation. It took approximately 2 months for Mica to transition from the Flex operation to the Called Upon operation. If the switch from Flex to Called Upon occurred in January, February, or March, then the system could be on the Called Upon operation by the end of April. If the switch occurred in April, then achieving the Called Upon operation by the end of the month would result in flows from Arrow in excess of 100 kcfs.

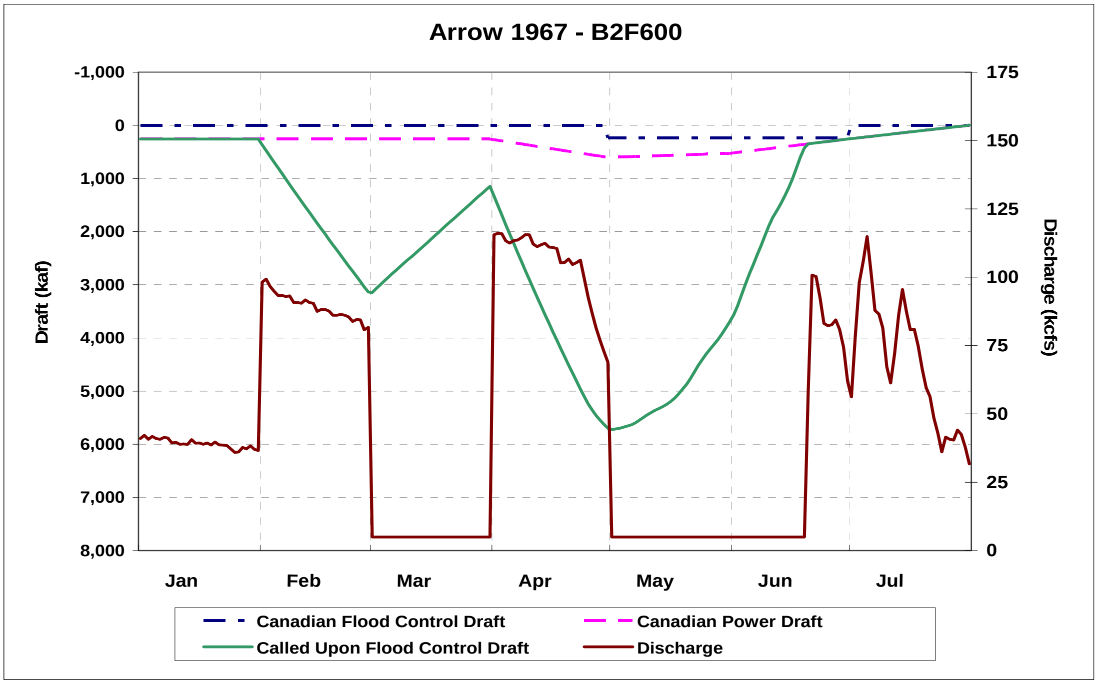
For years when Called Upon was triggered in one month and not needed in succeeding months, it was found that it took Mica and Arrow up to two months to recover from the Called Upon operation to the Flex operation. This analysis did not, however, consider B.C. domestic load requirements and other non-power constraints. It is unlikely that Mica could be reduced to minimum flow in winter without a very high risk to BC Hydro power reliability and risk of impacts to non-power requirements. Further investigation is required as to how much Flex operation can affect Called Upon operation.

3.4.4.7. Runoff Volume Forecast Changes in Called Upon Years

In some years the runoff volume forecasts fluctuated from month to month above and below the runoff volumes that trigger Called Upon flood control operations. When this occurs, Called Upon flood control can be triggered in one month, not triggered in the next month, and then triggered again in the following month. This can cause flow fluctuations that may be undesirable for fish and other purposes.

For example, Figure 3-14 illustrates this effect in water year 1967. With 600 kcfs as the maximum flow objective, Called Upon was first triggered in February, not triggered in March, and then triggered again in April. This caused Arrow month-average outflows to fluctuate from 100 kcfs to 3 kcfs and then back to above 100 kcfs in February, March, and April. Arrow reservoir attempted to fill back up to its intended power operation when Called Upon was not triggered in March. Further investigation is required to refine procedures for mitigating these impacts.

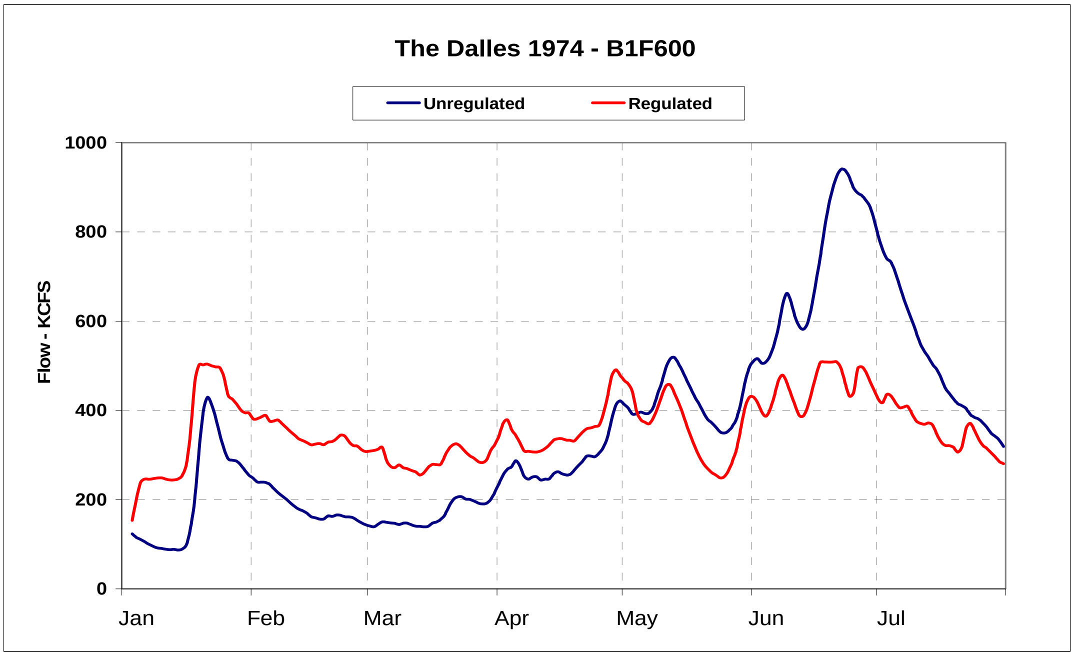
Figure 3-14 – Effects of Forecast Changes on Called Upon Operations



3.4.4.8. Prioritizing Between Winter and Spring Called Upon Flood Control

Modeling to control for winter flood events was not a primary objective for the Phase 1 studies; however, it was discovered that by regulating projects using the assumptions that were developed, Called Upon drafts increased flows to what might be considered undesirably high flows in the winter period. As a result, drawdown for Called Upon in January through April sometimes caused flows to be higher than spring flows. Figure 3-15 shows an example of how Called Upon drafts occurring in conjunction with a winter rain event could cause an increase in flow with a high unregulated winter flow event. In 1974 under the B1O600 scenario, the winter peak flow exceeded 500 kcfs. It is unlikely that the Entities would incur a deliberate and certain high flow to avoid the possibility of an uncertain high flow at a later time. Winter flows higher than spring flows was not a rare occurrence: for the A1F450 study, in 13 years the winter flows were higher than the spring flow; the B1F450 and B2F450 years showed 19 years and 14 years, respectively.

Figure 3-15 – Effects of Called Upon on High Winter Flows



3.5. CALLED UPON IMPACTS TO CANADIAN COMPOSITE STORAGE, ARROW PLUS DUNCAN OUTFLOW, GRAND COULEE, AND CANADIAN AND U.S. GENERATION

3.5.1. MODELING OVERVIEW

A second important goal of the Phase 1 Studies was to understand the impacts of Called Upon flood control operations on 1) Canadian and Grand Coulee reservoirs, 2) Arrow plus Duncan outflows, and 3) Canadian and U.S. generation. Called Upon implementation was assessed for Treaty Continues (A1) and Treaty is Terminated (B) scenarios. In order to determine the possible impacts to these three aspects of system operations, several modeling and operating criteria assumptions were made for:

- Flood control and Called Upon operation
- Canadian Flex operation
- Short-term modeling

The results from the long-term modeling (AOP or AOP-like) operating criteria, the Canadian Flex operation, and the Called Upon operations all provided input to the short-term power impact studies that were used to determine the impacts of Called Upon.

The following briefly describes these assumptions and overall approach for assessing Called Upon impacts.

Called Upon Operations. Called Upon was assumed to be implemented during short-term planning (drawdown period) and in real-time operations (drawdown and refill); however, for the purposes of the Phase 1 studies it was applied in the short-term modeling of the system. In years determined to require Called Upon storage from Canada, the Called Upon draft of Canadian projects was compared to how they otherwise would have drafted (which is dependent on the scenario being modeled) to assess the impact of Called Upon.

Canadian Flex Operation. Canadian Flex is the ability of Canada to balance water between Canadian reservoirs so long as the total Canadian storage content and the flow across the border is the same as defined in Treaty planning. The Canadian Flex operation was applicable only in the Treaty Continues A1 scenarios. Therefore, when assessing the impacts of Called Upon in the A1 scenarios, the Called Upon draft was compared to the Canadian Flex operation in years where Called Upon was required.

Short-term Modeling. Since Canadian Flex and Called Upon operations are to be implemented in short-term or real-time operations, it was important to model their implementation as closely as possible using existing modeling techniques. In order to assess the impacts of these two operations, power impact studies were conducted for each scenario. These power impact studies most closely resembled 70-year continuous hydroregulation studies using monthly time-steps, in forecast mode, with Called Upon and/or Flex operations applied where appropriate. The monthly model did not capture the daily and hourly variability that is necessary to fully understand the impacts of Called Upon on Canadian generation.

Overall Approach. For each of the A1 and B scenarios a set of two short-term or power impact models were compared. For each of these studies, a base "no-Called Upon" and a "Called Upon" study was completed.

The no-Called Upon study set the Canadian projects to their Flex operation in the A1 scenarios, the Canadian local flood control operation in B1, or the Canadian only power operation in the B2 scenarios.

In the Called Upon study, the Canadian projects were set to the same operation as in the no-Called Upon studies, except in those years when Called Upon was required by the U.S. In these years the Canadian operation was set to the requested Called Upon draft.

In both studies, the U.S. projects were operated according to existing SRDs in years where the Called Upon threshold was not exceeded and to an "effective use" operation in years where the threshold was exceeded.

Essentially, only the Called Upon years were different between each set of studies. Table 3-19 describes the Canadian operations in each set of studies. By performing a no-Called Upon and a Called Upon set of studies, the impact of Called Upon to Canadian and U.S. operations was assessed. The end result was a monthly difference in storage operations and generation between the Called Upon and no-Called Upon scenarios. For the purposes of the Phase 1 studies, no value was assigned or calculated for the generation differences.

Table 3-19 – Canadian Reservoir Operation Applied in Each Comparison

Description of Each Set	A1	B1	B2
No-Called Upon	Flex	Canadian local flood control	Canadian only power operation
Called Upon	Flex or Called Upon	Canadian local flood control or Called Upon	Canadian only power operation or Called Upon

Scenarios and Comparisons. The following sections focus on comparing the A1 and B2 studies to assess the impacts of Called Upon between a Treaty Continues scenario and a Treaty is Terminated scenario. The B1 study was also modeled in order to look at Called Upon needs under the Treaty is Terminated condition with a Canadian local flood control operation only. Each of the following graphs illustrates the impacts of Called Upon, plotting the Called Upon only years against the average 70-year values to show the relative differences between Called Upon and the overall 70-year set. For the 600 and 450 kcfs maximum flow objective at The Dalles, there were 21 and 52 Called Upon years, respectively. Caution should be used when interpreting the graphs and tables that compare the 70-year average data to Called Upon years, as the data is affected by the frequency of Called Upon years and the tendency for Called Upon years to have higher annual volume runoff.

3.5.2. CALLED UPON IMPACTS TO CANADIAN COMPOSITE STORAGE

Canadian composite storage in the Phase 1 studies is the combined total Treaty storage of Mica, Arrow, and Duncan reservoirs. Under a Treaty Continues scenario (A1), the maximum storage used was 15.5 Maf. However, in the Treaty is Terminated scenarios (B1 and B2), the full storage amount would be available for use. Therefore, under the Treaty is Terminated scenarios the full Canadian Treaty and non-Treaty[30] storage amount of 20.4 Maf was used. For the Canadian composite storage figures, when the storage value dropped below zero, the storage had been drafted below the Treaty storage total of 15.5 Maf and was drafting further into the full storage amount.

3.5.2.1. Cross-study Comparison – A1, B2 (Figure 3-16)

Because the methodology used to draft the Canadian projects for Called Upon was essentially the same for either the 600 kcfs or the 450 kcfs maximum flow objective (i.e., the same SRDs were used despite the differences in flood control flow objectives), all the Called Upon years drafted Canadian composite storage to roughly the same level.

Implementation of Called Upon resulted in a deeper draft of the Canadian composite storage than the draft for Canadian Flex operation (A1) or the Canadian power draft (B2) scenarios. In both scenarios, additional winter draft was required to create space for regulation of the spring runoff. Because the Canadian only power operation (B2) required less draft than the Treaty operation (A1), the Called Upon draft from the assumed Canadian project operations was more for the Canadian only power operation than the Treaty operation.

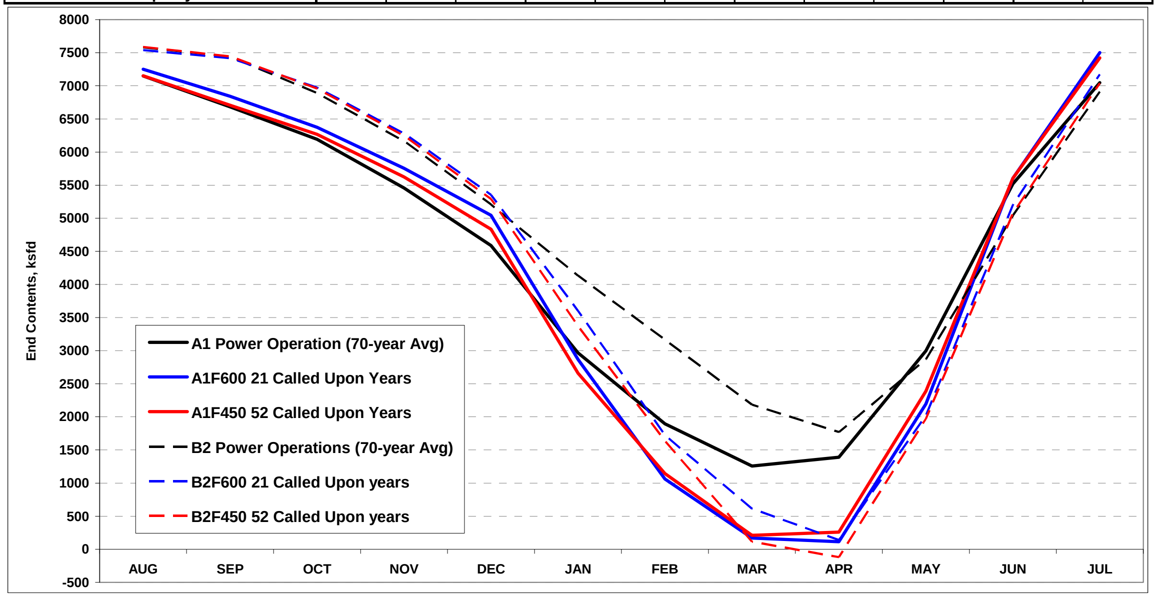
During the August to December period, any differences between the power and Called Upon operations were due to differences in the average power operations over 70 years versus over the Called Upon years only. There were no Called Upon operations during this period.

[30] Mica was constructed with more storage than is specified in the Treaty. The additional 5 Maf of storage is called Non-Treaty storage, and its use is managed under additional agreements between the Entities.

Figure 3-16 – Mica + Arrow + Duncan Storage Content (A1, B2)

Mica+Arrow+Duncan End Contents, ksfd

ksfd	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
A1 Power Operation (70-year Avg)	7148	6682	6192	5458	4586	2965	1896	1258	1390	2999	5520	7048
A1F600 21 Called Upon Years	7252	6842	6372	5754	5045	2866	1061	170	114	2196	5605	7502
A1F450 52 Called Upon Years	7151	6707	6266	5624	4835	2660	1143	211	258	2389	5605	7423
B2 Power Operations (70-year Avg)	7582	7441	6892	6165	5208	4134	3164	2184	1770	2871	5042	6911
B2F600 21 Called Upon years	7540	7418	6975	6280	5350	3603	1721	612	138	2021	5203	7174
B2F450 52 Called Upon years	7589	7446	6959	6245	5289	3371	1636	114	-119	1971	5074	7039



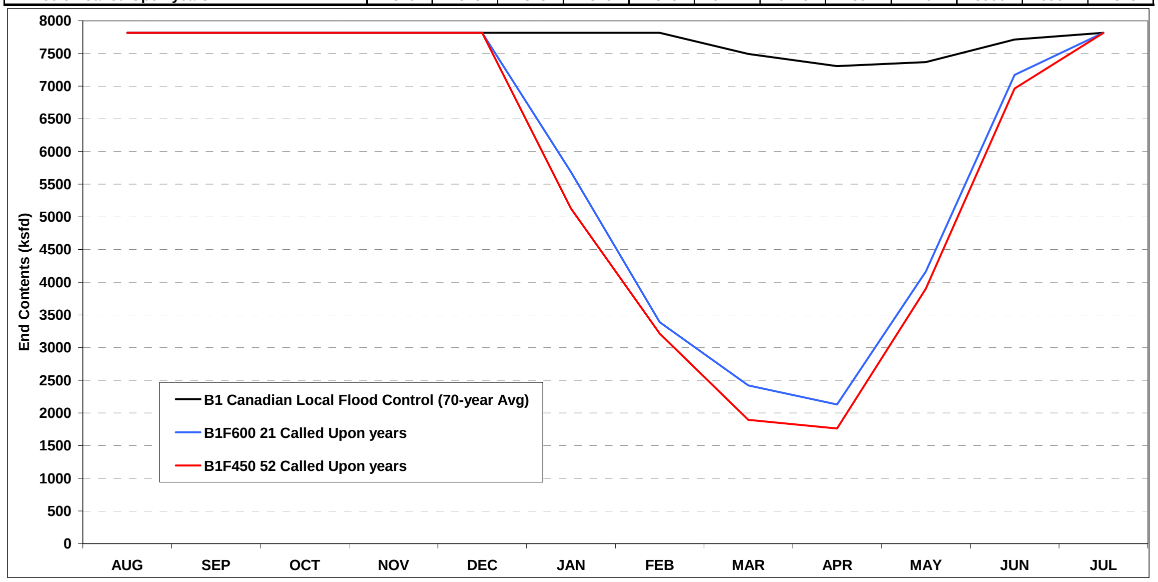
3.5.2.2. B1 Scenarios (Figure 3-17)

Figure 3-17 shows the Canadian composite storage if the projects were operated to provide only local flood control protection in Canada compared with the implementation of Called Upon from Canadian storage by the U.S. for flood control. In the B1 studies, the Canadian local flood control maintains the Canadian composite storage relatively full until the March through June period, when there is a small draft and refill for local flood control. As expected, the Called Upon scenarios resulted in a deeper draft of the Canadian composite storage. Once again, due to the methodology used in the Phase 1 studies, the overall Called Upon draft of the Canadian composite storage was relatively close for the 600 kcfs and 450 kcfs maximum flow objectives at The Dalles.

Of interest, Canadian power draft with Called Upon under the Treaty is Terminated scenario (B2) drafted the Canadian composite storage deeper than the B1 scenario. In the B2 scenarios there was limited incidental flood control benefit from the Canadian power operation. In the scenario provided, most of the Canadian power draft came from Mica and was usually more than needed for U.S. flood control. The most effective Canadian storage for Called Upon is from Arrow; however, the preferred Canadian operation at Arrow was to keep it as full as possible year around. Because of this preferred operation at Arrow, the U.S. was frequently required to request Called Upon storage from Arrow to create needed Called Upon space. Therefore, the total Mica power draft plus the Mica and Arrow Called Upon draft in B2 was greater than the total Mica and Arrow Called Upon draft in B1. In essence, the Canadian preferred power draft did not necessarily provide the specific space and location needed for the most effective use of Canadian storage for U.S. flood control.

Figure 3-17 – Mica, Arrow, Duncan Composite Storage Contents B1

Mica+Arrow+Duncan End Contents, ksfd												
ksfd	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
B1 Canadian Local Flood Control (70-year Avg)	7815	7815	7815	7815	7815	7815	7815	7493	7305	7368	7713	7815
B1F600 21 Called Upon years	7815	7815	7815	7815	7815	5686	3388	2420	2130	4161	7171	7815
B1F450 52 Called Upon years	7815	7815	7815	7815	7815	5127	3213	1892	1761	3900	6962	7813



3.5.3. Called Upon Impacts to Arrow plus Duncan Outflow

While flows across the border into the U.S. are a result of various outflows from Arrow, Duncan, Libby, Kootenay Lake, and the Pend Oreille River, the following looks at only the outflows from Duncan and Arrow to reflect the regulated changes specific to Canadian Treaty projects and operations.

3.5.3.1. Cross-study Comparison – A1, B2 (Figure 3-18)

The Canadian power operation provided for the Treaty is Terminated (B2) scenarios attempted to maintain Arrow as close to full as possible year around, resulting in a relatively steady outflow, on average, from Arrow and Duncan, with only a slight increase during the April-June period (dashed black line in Figure 3-18).

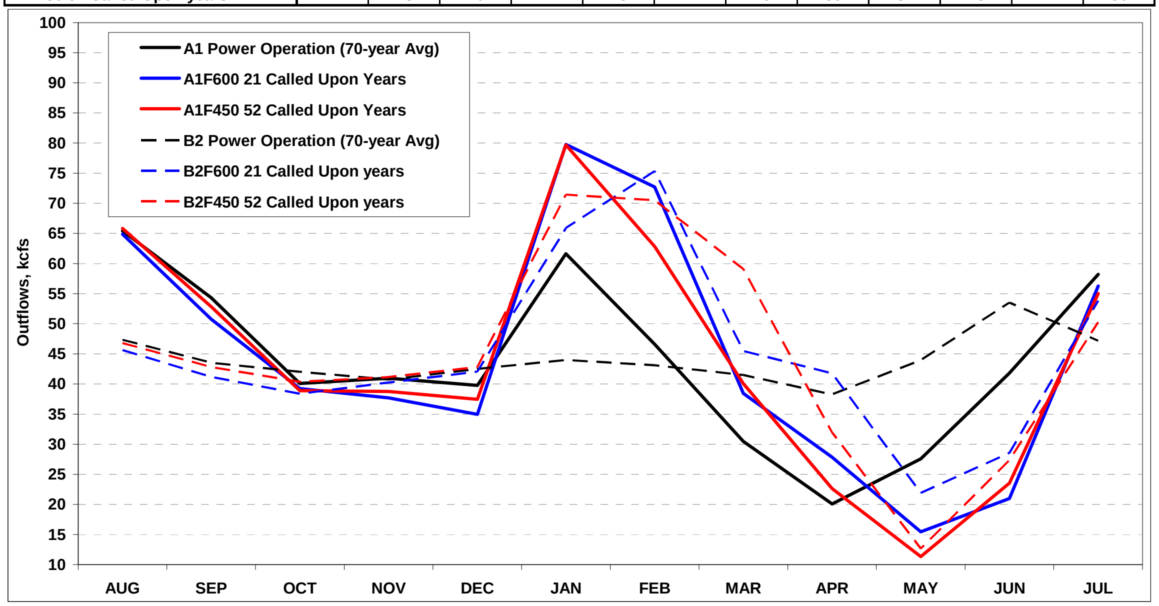
Under the Treaty Continues scenario (A1) the shape of the Arrow plus Duncan outflows was a result of an optimized, coordinated power draft and any Called Upon requirements, resulting in deeper winter storage drafts and higher releases in the January to March period (solid black line).

For the Treaty is Terminated scenarios (B2), the Arrow plus Duncan outflows mimicked the outflow shape of the Treaty Continues scenarios (A1) only when Called Upon was implemented. In fact, Called Upon years resulted in more dramatic seasonal swings than the A1 70-year average, with even higher outflows in the winter and lower outflows during the runoff season or spring.

Figure 3-18 – Arrow plus Duncan Average Outflows (A1, B2)

Arrow+Duncan Outflows, kcfs

kcfs	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
A1 Power Operation (70-year Avg)	65	54	40	41	40	62	47	30	20	28	42	58
A1F600 21 Called Upon Years	65	51	39	38	35	80	73	38	28	15	21	56
A1F450 52 Called Upon Years	66	53	39	39	37	80	63	40	23	11	24	55
B2 Power Operation (70-year Avg)	47	44	42	41	43	44	43	41	38	44	53	47
B2F600 21 Called Upon years	46	41	38	40	42	66	75	45	42	22	29	54
B2F450 52 Called Upon years	47	43	40	41	43	71	70	59	32	13	27	50



3.5.3.2. Assessment of 20 Lowest January-July Volume Years

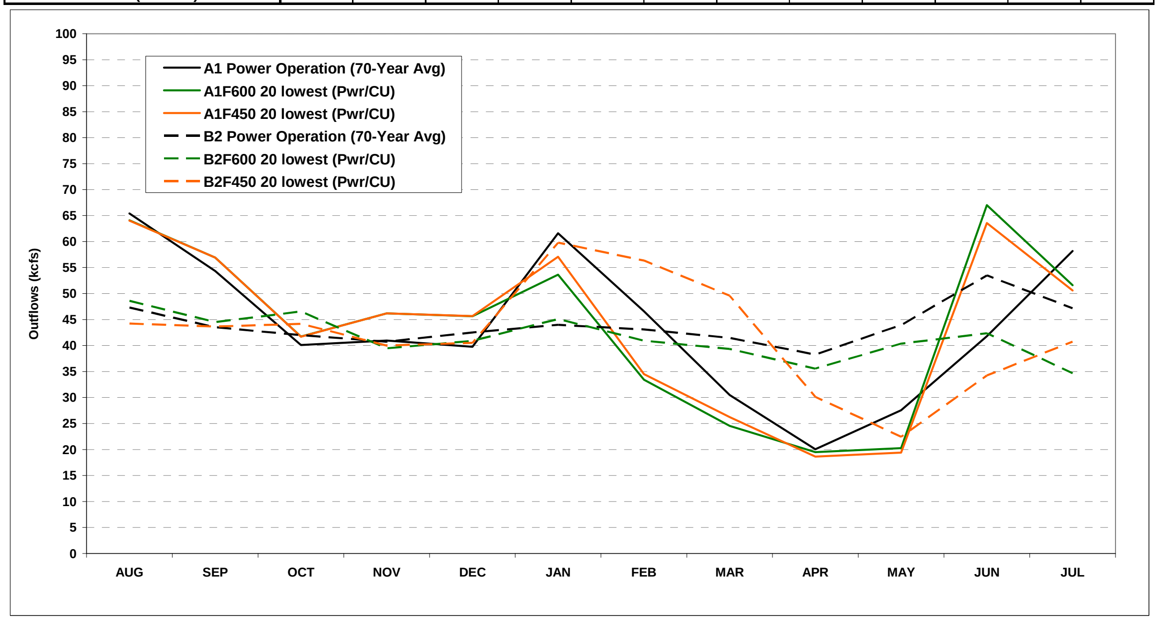
While Figure 3-18 provides an overall perspective of how Called Upon implementation increased Arrow plus Duncan outflows during the winter and decreased outflows during the spring or refill season, it does not show the overall impact to the Arrow plus Duncan outflows from low water years, when Called Upon is less of a factor in the operation of the system. Figure 3-19 shows the 20 lowest January-July volume years compared to the 70-year average power operations for the A1 and B2 scenarios. Even though this analysis examined the 20 lowest January through July runoff years, there was still one Called Upon year in the 600 kcfs flow objective set and five Called Upon years in the 450 kcfs flow objective set. This frequency was either relatively low (as in the 600 kcfs set) or of minimal impact due to a limited implementation of Called Upon during the year, as with the five cases at the 450 level (none of these years took Grand Coulee to empty at the end of April).

For the A1 studies with Called Upon flood control, the Arrow plus Duncan outflows in the 20 lowest years were, in general, less than the 70-year average power operation for January through May and higher the remainder of the year. Outflows still increased in the winter, but not to the level as with the full set of Called Upon years or as high as the power operation. There was little difference in outflows between the 450 kcfs and 600 kcfs flood control objectives.

For the B2 studies in the 20 lowest years, the 600 kcfs objective was relatively close to the 70-year power operation, generally maintaining a steady 35-45 kcfs outflow from Arrow throughout the year, despite low water conditions. At the 450 kcfs flood control objective, the Arrow plus Duncan outflows were much higher in January through March, and lower during April through June, but overall less than the 70-year power operation during this period. This difference in shape from the 600 kcfs objective is due to the influence of the five Called Upon years at the 450 kcfs flow objective.

Figure 3-19 – Arrow plus Duncan Outflows 20 Lowest Years (based on January-July Volume)

Arrow plus Duncan Outflows, kcfs Outflows for 20 lowest water years based on The Dalles Jan-Jul observed volumes												
kcfs	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
A1 Power Operation (70-Year Avg)	65	54	40	41	40	62	47	30	20	28	42	58
A1F600 20 lowest (Pwr/CU)	64	57	42	46	46	54	33	25	20	20	67	52
A1F450 20 lowest (Pwr/CU)	64	57	42	46	46	57	35	26	19	19	64	51
B2 Power Operation (70-Year Avg)	47	44	42	41	43	44	43	41	38	44	53	47
B2F600 20 lowest (Pwr/CU)	49	45	47	39	41	45	41	39	36	40	42	35
B2F450 20 lowest (Pwr/CU)	44	44	44	40	41	60	56	50	30	22	34	41

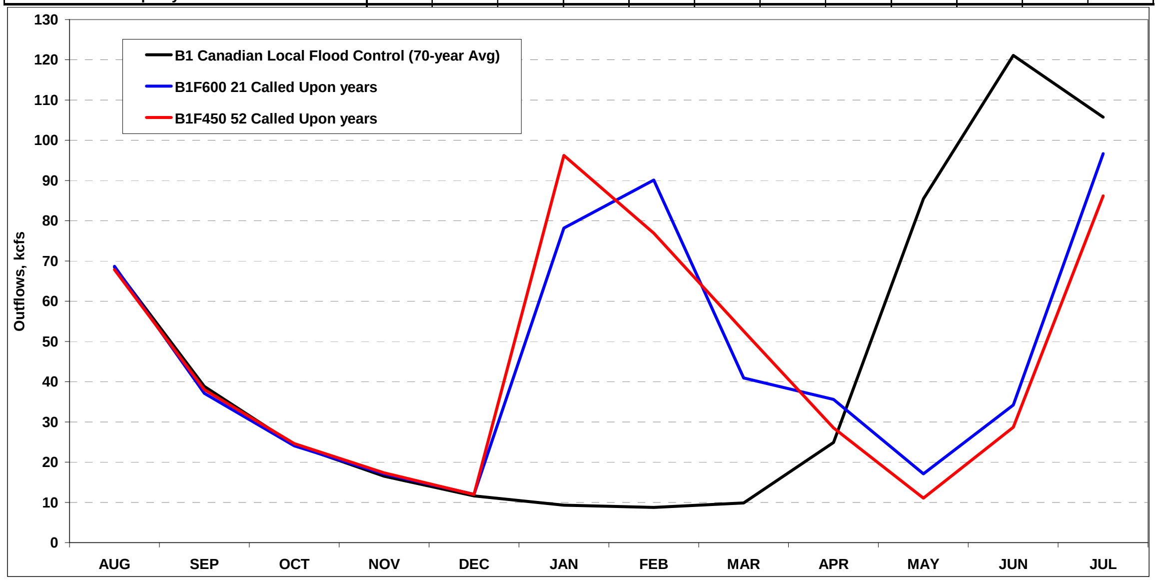


3.5.3.3. B1 Scenarios (Figure 3-20)

Figure 3-20 shows the shape of Arrow plus Duncan outflows should the Canadian projects operate for local flood control only (black line). Both the 600 kcfs and the 450 kcfs maximum flow objectives resulted in relatively the same Called Upon outflows due to the methodology used in the Phase 1 studies.

Figure 3-20 – Arrow plus Duncan Average Outflow for B1

Arrow plus Duncan Outflows, kcfs												
kcfs	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
B1 Canadian Local Flood Control (70-year Avg)	68	39	24	17	12	9	9	10	25	85	121	106
B1F600 21 Called Upon years	69	37	24	17	12	78	90	41	36	17	34	97
B1F450 52 Called Upon years	68	38	25	17	12	96	77	53	29	11	29	86



3.5.4. Called Upon Impacts to Grand Coulee Reservoir Elevation

3.5.4.1. Cross-study Comparison – A1, B2 (Figure 3-21)

For both the Treaty Continues (A1) and the Treaty is Terminated (B2) scenarios, implementation of procedures to make effective use of U.S. storage before requesting Called Upon caused Grand Coulee to draft substantially deeper during the Called Upon years compared to non-Called Upon years. Implementation of effective use caused Grand Coulee to draft to 1208 feet (minimum pool) 28-30 times out of the 52 Called Upon years for the 450 kcfs maximum flow objective at The Dalles and only 9-10 times for the 600 kcfs objective. Grand Coulee refilled in all years.

In non-Called Upon years, Grand Coulee's flood control drafts were computed based on its SRDs. There were, however, some differences in how the simulation was conducted between scenarios A1 and B2. The difference in A1 and B2 70-year average elevation shown in Figure 3-21 is an artifact of the modeling and not a real difference between scenarios A1 and B2.

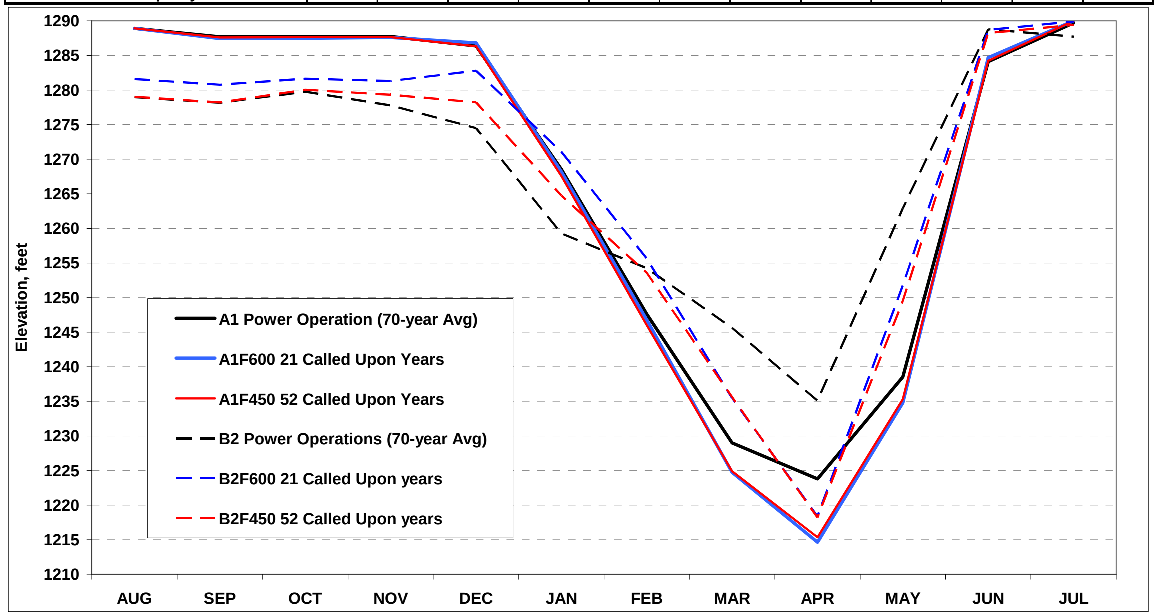
In Figure 3-21, all Called Upon years drafted Grand Coulee deeper than without Called Upon; however, the lowest point on the figure does not show Grand Coulee reaching 1208 feet on average for the Called Upon years only. This is because in some years Called Upon was either no longer required by the end of April or because refill was initiated prior to the end of April due to an early runoff.

Although Grand Coulee refilled in all years, reduced August outflows from Arrow plus Duncan in the Treaty is Terminated (B2) scenarios caused Grand Coulee to draft to meet power needs, resulting in a lower Grand Coulee elevation starting in August and lasting until the beginning of the winter flood control draft period.

Figure 3-21 – Grand Coulee Average Month-Ending Elevation (A1, B2)

Grand Coulee Ending Elevation, Feet

feet	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
A1 Power Operation (70-year Avg)	1289	1288	1288	1288	1286	1269	1248	1229	1224	1239	1284	1290
A1F600 21 Called Upon Years	1289	1287	1287	1288	1287	1268	1247	1225	1215	1235	1285	1290
A1F450 52 Called Upon Years	1289	1288	1288	1288	1286	1268	1246	1225	1215	1235	1284	1290
B2 Power Operations (70-year Avg)	1279	1278	1280	1278	1274	1259	1254	1246	1235	1263	1289	1288
B2F600 21 Called Upon years	1282	1281	1282	1281	1283	1271	1256	1235	1218	1252	1289	1290
B2F450 52 Called Upon years	1279	1278	1280	1279	1278	1265	1254	1236	1218	1249	1288	1289



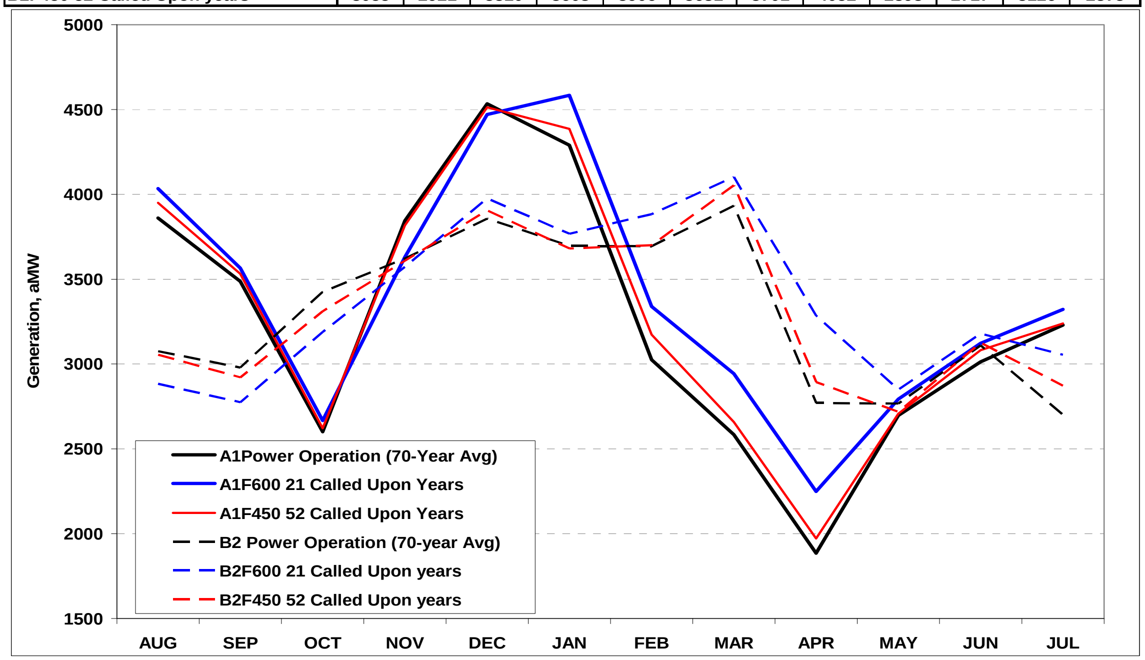
3.5.5. CALLED UPON IMPACTS TO CANADIAN GENERATION

3.5.5.1. Cross-study Comparison – A1, B2 (Figure 3-22)

Figure 3-22 shows the Canadian generation patterns for scenarios A1 and B2 with and without Called Upon, which is driven by the two distinct power operations used in each study—the Flex operation provided for A1 and the Canadian power operation provided for B2.

Figure 3-22 – Canadian Generation (A1, B2)

Canadian Generation* - aMW												
aMW	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
A1Power Operation (70-Year Avg)	3861	3487	2601	3845	4534	4290	3025	2584	1885	2697	3013	3230
A1F600 21 Called Upon Years	4034	3565	2667	3630	4470	4584	3338	2942	2249	2793	3122	3323
A1F450 52 Called Upon Years	3950	3531	2621	3817	4514	4386	3172	2658	1972	2707	3081	3239
B2 Power Operation (70-year Avg)	3076	2979	3424	3622	3857	3696	3695	3933	2771	2767	3109	2701
B2F600 21 Called Upon years	2884	2774	3188	3573	3976	3768	3883	4102	3284	2849	3179	3055
B2F450 52 Called Upon years	3055	2921	3310	3608	3906	3681	3701	4052	2893	2717	3126	2873



**Canadian Generation includes: Mica+Revelstoke+Arrow+Corra Linn+U. Bonnington+L. Bonnington+South Slocan+Canal+Brilliant+Seven Mile+Waneta*

Table 3-20 provides a summary of the generation differences due to Called Upon within each study. In general, annual Canadian generation losses due to Called Upon flood control operations were relatively small compared to the total generation. However, the monthly impacts within a given Called Upon year may be potentially much greater. For the Treaty Continues (A1) scenario, the average loss for Canadian generation was 24-27 aMW, ranging from a gain of 155 aMW to a loss of 191 aMW. The Treaty is Terminated (B2) scenario comparisons produced an average loss of generation of 60-73 aMW, showing the greater generation impact of Called Upon draft in B2 compared to A1. The range of impact varies from a gain of 545 aMW to a loss of 519 aMW.

In reality, the impact to the Canadian operation will be highly dependent upon the Canadian real-time power and non-power needs as well as market conditions. In order to fully understand the impacts of Called Upon to Canadian generation, daily modeling with variable peak, heavy, and light load hour sub-time steps will be necessary

Table 3-20 – Canadian Generation Difference Between Called Upon and Non-Called Upon Scenarios

Study		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug[1]	Jan-Aug aMW for all CU Years[2]	Years of Called Upon	70 year Annual Avg, aMW
Treaty Continues: Called Upon												
A1F600 (Flex)	Max	1	64	0	11	7	7	0	8			
A1F600 (Called Upon)	Average	-14	-25	-62	-32	-48	-28	-10	-1	-27	21	-5.5
	Min	-36	-114	-135	-77	-107	-118	-128	-15			
A1F450 (Flex)	Max	64	255	127	147	85	19	136	91			
A1F450 (Called Upon)	Average	-11	2	-58	-8	-41	-35	-24	2	-23	52	-11.4
	Min	-44	-139	-277	-131	-163	-156	-163	-61			
No Treaty: Called Upon, Canadian operation for power												
B2F600 (Canadian Power Op)	Max	0	194	37	10	3	2	65	27			
B2F600 (Called Upon)	Average	-68	-113	-119	-118	-103	-70	3	1	-73	21	-13.5
	Min	-407	-519	-184	-184	-178	-183	-6	-2			
B2F600 (Canadian Power Op)	Max	545	418	314	182	56	20	119	64			
B2F450 (Called Upon)	Average	-56	-60	-40	-75	-138	-79	-31	-3	-60	52	-30.2
	Min	-408	-519	-344	-214	-432	-241	-269	-84			
Generation differences = Called Upon Study - Base Case Study												
[1] Aug of next operating year												
[2] aMW values are for Called Upon years only												

3.5.6. Called Upon Impacts to U.S. System Generation

Figure 3-23 shows the U.S. generation patterns for scenarios A1 and B2. In the Treaty Continues scenario (A1), Called Upon shifted additional generation from spring into winter. Terminating the Treaty and relying on a Canadian power operation only (B2) resulted in significantly lower winter generation and higher spring generation for the U.S., essentially de-optimizing the U.S. power operation compared to the Treaty Continues scenarios (A1). Only after Called Upon is required in the Treaty is Terminated scenarios (B2) was there some reshaping of generation back into the winter; however, there was still relatively higher generation during the spring, a lower power value period.

Figure 3-23 – U.S. System Generation (A1, B2)

U.S. System Generation - aMW												
aMW	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
A1 Power Operation (70-year Avg)	12798	11829	10672	12720	14293	17887	17116	16022	15201	19525	19132	16753
A1F600 21 Called Upon Years	12976	11813	10918	13274	15582	21965	21147	19271	19171	21876	21097	18883
A1F450 52 Called Upon Years	12771	11748	10749	12955	14619	20220	19339	18097	17029	19446	19551	17350
B2 Power Operation (70-year Avg)	12650	10012	10572	12889	14176	15059	14271	16447	17417	21085	22375	16654
B2F600 21 Called Upon years	12532	9846	10831	13310	15724	18515	19965	20067	21220	22957	23331	19322
B2F450 52 Called Upon years	12524	9901	10592	12986	14533	17361	18037	19972	18922	20258	21586	17566

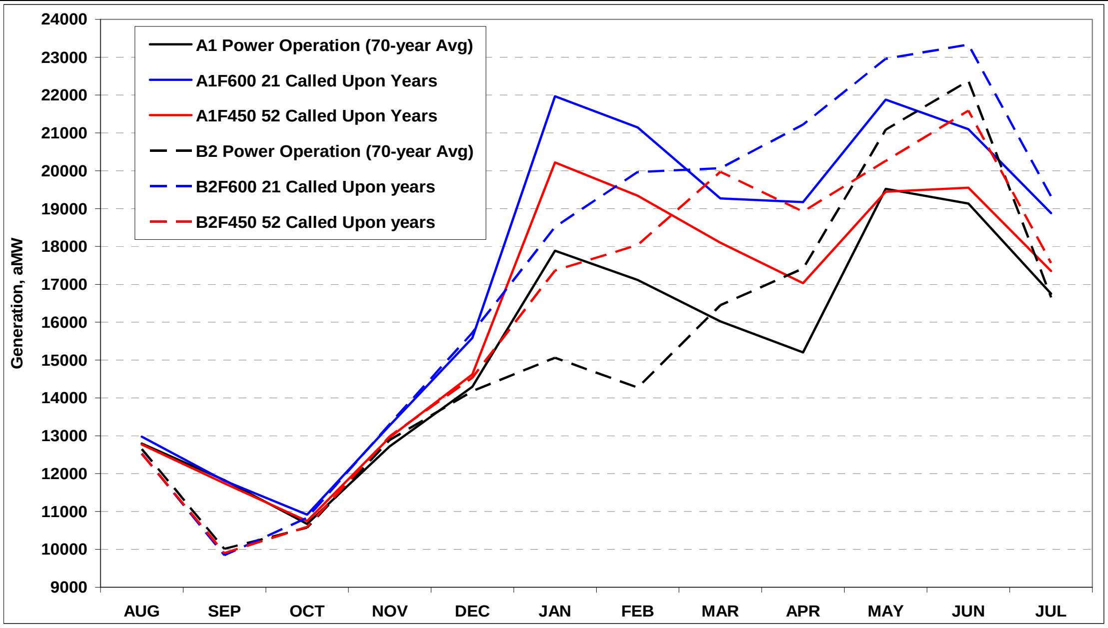


Table 3-21 provides a summary of the U.S. system generation differences due to Called Upon. The gain in annual average generation from Called Upon was small relative to total generation, ranging from 13 aMW to 60 aMW. The monthly impacts within a given Called Upon year can be much greater, as shown in Table 3-21.

Table 3-21 – U.S. System Generation Difference Between Called Upon and Non-Called Upon Scenarios

Study		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug[1]	Jan-Aug aMW for all CU Years[2]	Years of Called Upon	70 year Annual Avg, aMW
Treaty Continues: Called Upon												
A1F600 (Flex)	Max	1360	2985	2971	3731	133	85	20	30			
A1F600 (Called Upon)	Average	503	780	220	377	-629	-362	-273	-8	68	21	13.5
	Min	-41	-1412	-2787	-970	-1797	-1442	-1724	-99			
A1F450 (Flex)	Max	2229	3005	2691	3019	136	325	676	204			
A1F450 (Called Upon)	Average	784	564	530	64	-688	-520	-362	14	42	52	19.6
	Min	-137	-1367	-1539	-1356	-2347	-3088	-1810	-99			
No Treaty: Called Upon, Canadian operation for power												
B2F600 (Canadian Power Op)	Max	2371	4640	3630	3976	0	20	315	0			
B2F600 (Called Upon)	Average	1197	1778	86	73	-1003	-1004	-17	0	124	21	28.0
	Min	0	-2711	-2606	-2153	-2232	-2694	-342	0			
B2F600 (Canadian Power Op)	Max	6035	9636	8201	4411	272	191	490	70			
B2F450 (Called Upon)	Average	1917	2857	1888	-289	-2401	-2295	-484	-5	127	52	59.4
	Min	0	-2571	-2834	-3586	-6216	-5921	-3953	-82			
Generation differences = Called Upon Study - Base Case Study												

[1] Aug of next operating year

[2] aMW values are for Called Upon years only

3.5.6.1. Assessment of 20 Lowest January-July Volume Years

While Figure 3-23 provides an overall perspective on how Called Upon implementation would provide a shift in energy from the spring into the winter months, it does not show the overall impact to U.S. generation when Called Upon is less of a factor in the operation of the system. Figure 3-24 shows the 20 lowest January-July volume years compared to the 70-year average power operations for the A1 and B2 scenarios. Even though this analysis examines the 20 lowest January through July runoff years, there was still one Called Upon year in the 600 kcfs flow objective set and five Called Upon years in the 450 kcfs flow objective set. This frequency was either relatively low (as in the 600 kcfs set) or of minimal impact due to a limited implementation of Called Upon during the year, as with the five cases at the 450 level (none of these years took Grand Coulee to empty at the end of April).

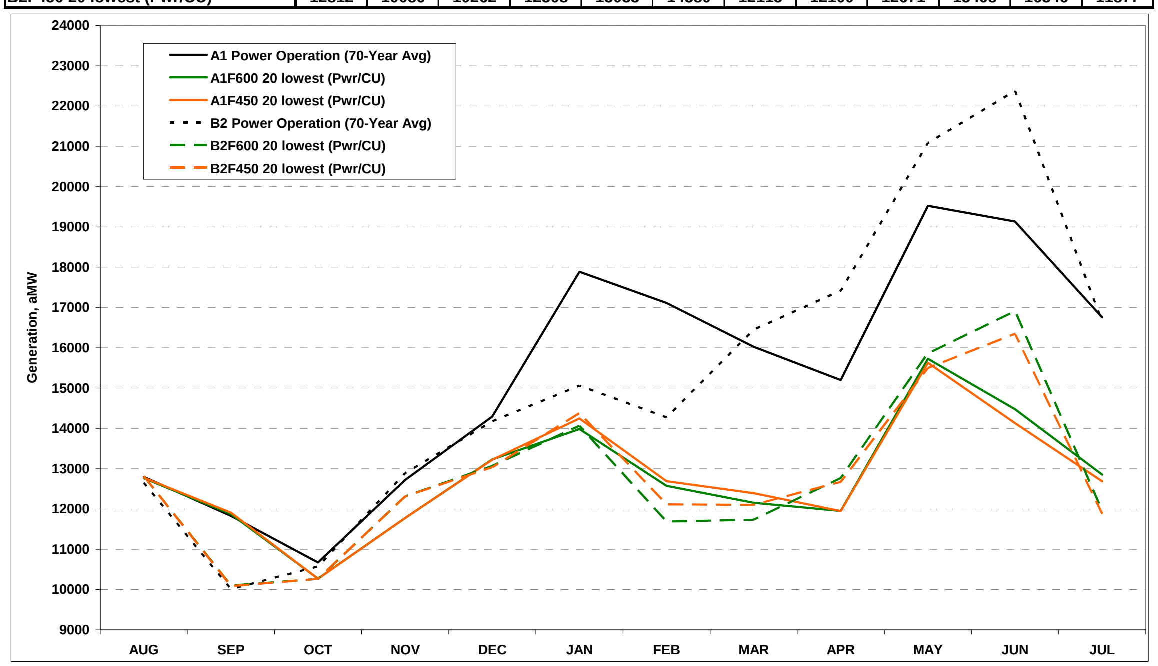
As expected, the results show that in low water conditions, the U.S. System generation was substantially lower than the 70-year average generation. Also, the A1 and B2 generation shape and magnitude were generally aligned, with the exception of the months of June and September, whether relying on a coordinated Treaty operation or an independent Canadian power draft.

Figure 3-24 – U.S. System Generation 20 Lowest Years (based on January-July volume)

U.S. System Generation, aMW

US System Generation for 20 lowest water years based on The Dalles Jan-Jul observed volumes

aMW	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
A1 Power Operation (70-Year Avg)	12798	11829	10672	12720	14293	17887	17116	16022	15201	19525	19132	16753
A1F600 20 lowest (Pwr/CU)	12764	11872	10271	11777	13228	13985	12576	12155	11952	15725	14476	12852
A1F450 20 lowest (Pwr/CU)	12778	11909	10267	11774	13218	14242	12692	12390	11945	15629	14130	12685
B2 Power Operation (70-Year Avg)	12650	10012	10572	12889	14176	15059	14271	16447	17417	21085	22375	16654
B2F600 20 lowest (Pwr/CU)	12813	10098	10265	12309	13068	14061	11686	11735	12768	15862	16910	11957
B2F450 20 lowest (Pwr/CU)	12812	10086	10262	12308	13033	14380	12115	12100	12671	15498	16346	11877



3.6. 70-YEAR AVERAGE AND CRITICAL PERIOD GENERATION

The following section describes the general findings of the A1, B1, and B2 studies, on an average basis, with respect to 70-year average generation and U.S. Critical Period generation.

In this phase, the power impact studies were performed with a monthly time-step model using the monthly average Called Upon flood control flow. However, because the Called Upon and Canadian Flex operation are both daily operations, the monthly time-step study can provide only a rough estimate of the generation impact. Daily modeling with variable peak, heavy, and light load hour sub-time-steps would be a more appropriate tool for future study to estimate the impact on both daily energy and capacity.

3.6.1. 70-YEAR AVERAGE GENERATION

Table 3-22 shows the 70-year average generation for the Canadian projects, the U.S. Federal System, and U.S. Total System for each of the forecast scenarios from A1 (Treaty Continues), B1 (Treaty is Terminated with only Canadian local flood control), and B2 (Treaty is Terminated with a pre-defined Canadian power draft).

Table 3-22 – Generation by Scenario (70-year Average)

Study	70-Year Average Generation (aMW)		
	Canadian	U.S. Federal	U.S. System
Treaty Continues			
A1F600 (Pwr)	3258	9419	15322
A1F600 (Pwr/CU)	3253	9429	15336
A1F450 (Pwr)	3259	9417	15317
A1F450 (Pwr/CU)	3247	9433	15337
No Treaty, CDN local			
B1O600 (Pwr)[31]	2967	9327	15014
B1F600 (Pwr/CU)	3066	9420	15173
B1F450 (Pwr/CU)	3175	9501	15325
No Treaty, CDN Power			
B2F600 (Pwr)	3301	9498	15304
B2F600 (Pwr/CU)	3288	9518	15333
B2F450 (Pwr/CU)	3271	9516	15365

Table 3-22 provides the average annual generation for each scenario; however, the within-year variation between scenarios is much more dramatic. Table 3-23 shows these averages by month and comparing the Treaty Continues (A1) and Treaty is Terminated (B2) scenarios. In general, for the U.S. System there was a significant shift out of high-power need, high-value winter months (e.g., an average 2,619 aMW reduction in January U.S. System generation), into low-need, low-value freshet months (e.g., an average 3,036 aMW increase in June generation) when comparing Treaty is Terminated (B2) to Treaty Continues (A1). The similar average annual U.S. generation in scenarios A1 and B2 indicates that the Canadian operation reduced the same

[31] B1F600 (Pwr) was not modeled. A power study was done for only the B1O600 scenario.

amount of spill at U.S. facilities whether the Treaty continues or is terminated. The value for U.S. power under Treaty Continues is the regulation of water from low power value periods to high power value periods.

In addition to the changes in generation at Canadian projects, U.S. Mid-Columbia utilities, and the U.S. Federal System, there were significant reductions in generation for U.S. Pend Oreille River projects and Idaho Power Company's Middle-Snake River projects.

Table 3-23 – Monthly Differences between the Treaty is Terminated with Canadian Power Draft Scenario and the Treaty Continues Scenario (B2F minus A1F)

Canadian Generation, 70-year Average (aMW)

B2 – A1	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Avg
600 kcfs objective	-784	-508	823	-223	-653	-616	642	1329	860	52	83	-525	35
450 kcfs objective	-785	-511	825	-223	-679	-628	624	1363	835	0	63	-532	25

U.S. System Generation, 70-year Average (aMW)

B2 – A1	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Avg
600 kcfs objective	-141	-1814	-96	170	-95	-2619	-2544	399	2135	1446	3036	-27	**-3**
450 kcfs objective	-140	-1832	-104	163	-110	-2010	-1160	1288	1499	577	2164	-49	**28**

U.S. Federal Generation, 70-year Average (aMW)

B2 – A1	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Avg
600 kcfs objective	-357	-1074	0	298	162	-1612	-1480	433	1726	851	2245	-178	89
450 kcfs objective	-374	-1094	-7	294	125	-1114	-515	1046	1182	157	1480	-197	83

U.S. Mid-Columbia Utilities,[32] 70-year Average (aMW)

B2 – A1	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Avg
600 kcfs objective	-52	-380	-30	-4	-15	-540	-621	73	432	66	462	23	-46
450 kcfs objective	-48	-383	-30	-4	-26	-272	-237	225	281	-101	372	23	-16

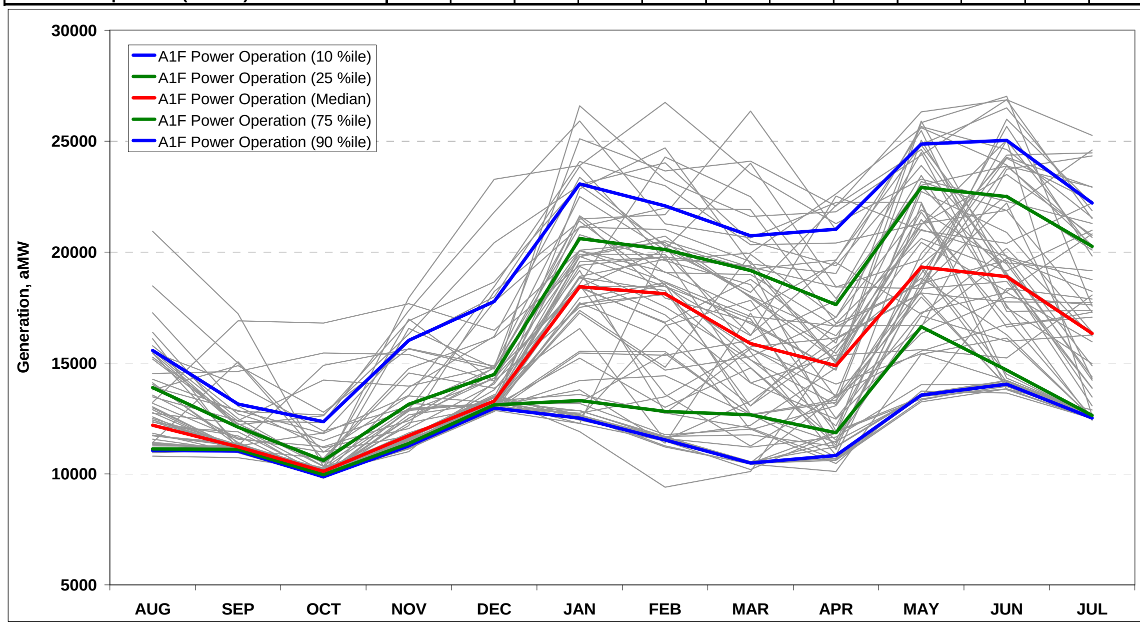
[32] The non-Federal project owners, referred to as the "Mid-Columbias" due to the location of their dams on the Columbia River, which provide 27.5 percent of the agreed Canadian Entitlement energy return.

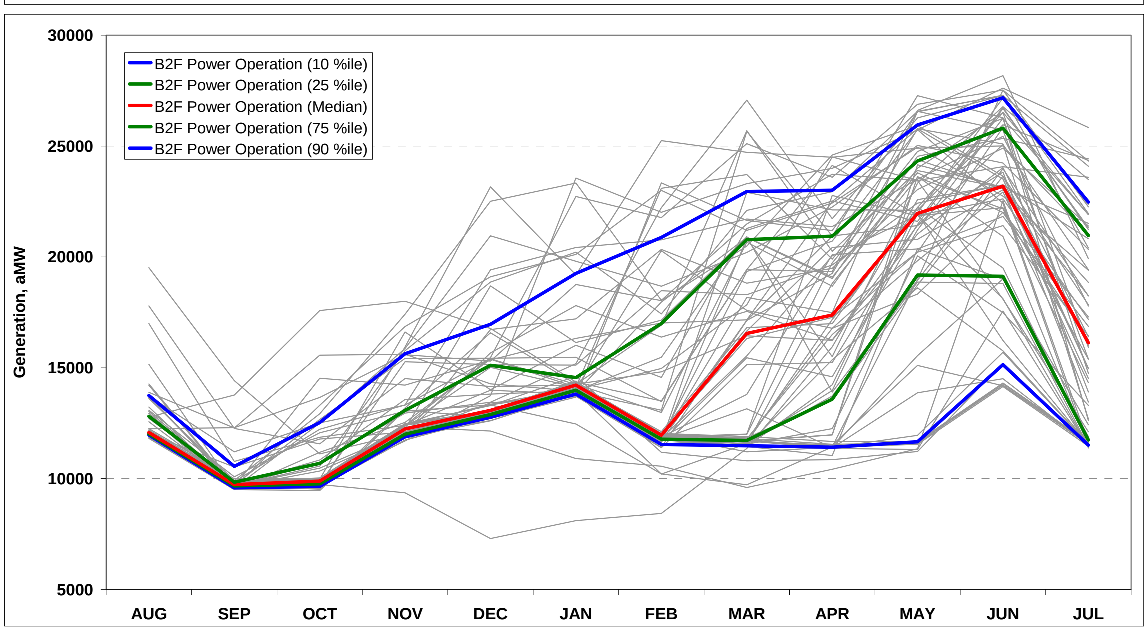
In addition to within-year variability, year-to-year variability can also be dramatic. Figure 3-25 is an example of the year-to-year variability for the B2 power operation scenario for U.S. System generation.

Figure 3-25 – 70 Years of U.S. System Generation Variability for A1F and B2F

U.S. System Generation Variability - aMW

aMW	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
A1F Power Operation (10 %ile)	11051	11036	9875	11269	12974	12518	11533	10499	10833	13552	14042	12524
A1F Power Operation (25 %ile)	11130	11101	9966	11379	13113	13306	12814	12667	11857	16635	14680	12638
A1F Power Operation (Median)	12199	11224	10114	11723	13287	18435	18121	15877	14886	19321	18890	16329
A1F Power Operation (75 %ile)	13889	12113	10611	13145	14483	20609	20114	19169	17635	22912	22505	20261
A1F Power Operation (90 %ile)	15566	13152	12354	16017	17775	23074	22086	20738	21026	24871	25036	22217
B2F Power Operation (10 %ile)	11966	9583	9651	11885	12769	13812	11544	11485	11414	11665	15140	11507
B2F Power Operation (25 %ile)	12013	9671	9763	12005	12891	13986	11774	11716	13579	19186	19128	11746
B2F Power Operation (Median)	12080	9732	9890	12239	13075	14220	11962	16551	17379	21965	23185	16126
B2F Power Operation (75 %ile)	12809	9839	10689	13077	15111	14558	16993	20779	20941	24328	25805	20961
B2F Power Operation (90 %ile)	13752	10544	12531	15630	16961	19252	20873	22952	23008	25956	27177	22471





3.6.2. Critical Period Generation

The Critical Period is the period in the historical streamflow record for the Columbia River System during which the least amount of electrical energy can be generated while fully drafting the reservoirs according to seasonal demands. It generally defines the generation capabilities of the system under low water conditions, typically referred to as the Firm Energy Load Carrying Capability (FELCC). The critical period for the A1 scenarios was August 16, 1929 - February 1932. For the B2 scenarios, the critical period was shorter: August 1, 1936 - April 15, 1937. The FELCC for the U.S. Federal and System generation also decreased between the B2 and A1 scenarios.

For Study B2 compared to Study A1 (Table 3-24):

U.S. Federal decreased by 139 aMW
U.S. System decreased by 225 aMW

Although the hypothetical Canadian power operation under the B2 studies showed little change to the average annual U.S. generation, it reduced the U.S. firm energy capabilities, indicating a diminished FELCC under low water conditions. As well, the reduced critical period (from 4 years to 1 year) may impact power reliability during a prolonged dry sequence.

Table 3-24 – Study A and B2 Critical Period and Critical Period Generation

Study	U.S. Federal		U.S. System	
	Critical Period	CP Generation aMW	Critical Period	CP Generation aMW
A1 AOP (Joint Optimum)	Aug 16, 1929 - Feb 1932	7202	Aug 16, 1929 - Feb 1932	11909
B2 600 (Base Case)	Aug 1, 1936 - Apr 15, 1937	7063	Aug 1, 1936 - Apr 15, 1937	11684

4. SUMMARY AND KEY FINDINGS

The Phase 1 technical studies provided a broad range of information and data that required considerable assessment and evaluation. The outcomes were a result of not only the scenarios selected, but also the assumptions and the modeling methodologies employed. As a result, considerable review was required to understand these outcomes and results. This section is meant to summarize and focus on the key outcomes and conclusions from the Phase 1 studies.

4.1. CALLED UPON FLOOD CONTROL

- Regardless of whether the Columbia River Treaty continued after 2024, changes in flood control operations from the FCOP to Called Upon had significant effects on the operations of both U. S. and Canadian storage reservoirs.
- The frequency that Called Upon operations was required was driven by the procedure and maximum flood control objective at the Dalles, Oregon. Based on the assumed procedure and objectives used in these studies, Called Upon storage in Canadian reservoirs was needed 21 years (30%) out of 70 years for every scenario when the maximum flow objective at The Dalles was 600 kcfs, and 52 years (74%) when 450 kcfs was the maximum flow objective. The joint study team believes those results overestimated the frequency of Called Upon years. Refinement of models, assumptions, and evaluation criteria is recommended to better estimate the frequency and duration of Called Upon storage needs (see section 5). Although flow objectives of 600 kcfs and 450 kcfs were used in the studies, there are differences between the Entities with regard to interpretation of Called Upon rights and obligations, including flood control objectives.
- The volume of Canadian storage requested by the U.S. for Called Upon was significantly less under the Treaty Continues studies (approximately 1-1.5 Maf on average) compared to Treaty is Terminated. Under Treaty is Terminated, the (power or flood control) draft at Canadian projects had a major impact on the additional draft needed for U.S. flood control, and there was a wide range (generally 5-11 Maf) in the volume of storage that was required for Called Upon.
- Canadian Treaty storage was very effective in controlling flood events in the United States. In the Phase 1 studies, peak flow at The Dalles was the best measure of flood control effectiveness of the scenarios investigated. Peak flows varied little across all the scenarios in Called Upon years. However, this study outcome was due largely to the modeling methodology used in the studies. When Called Upon operation was triggered, Canadian and U.S. reservoirs were all drafted to the same volume regardless of maximum flow objective, and the regulation in the spring was similar. While this approach was effective in controlling flooding in the U.S., it may not represent the most efficient use of water and storage across multiple operating purposes. Other strategies and procedures for implementing Called Upon operations need to be investigated (see section 5).
- Most of the Called Upon draft was required from Arrow reservoir since it is the most effective Canadian reservoir for managing reductions in flows at The Dalles. Because of the deep power draft at Mica, Called Upon did not usually affect Mica, and similarly, had only a minor impact at Duncan.

- A cursory evaluation of the impacts of Called Upon and Flex operations on each other showed that it was physically possible to transition from a Flex operation to a Called Upon operation. However, having Mica on minimum flow (and therefore low generation amounts) for up to three months in winter in order to transition to a Called Upon operation poses a high risk to BC Hydro power reliability and may impact non-power requirements. The impact of Flex on Called Upon needs to be investigated further (see section 5).

4.2. POWER LOADS AND RESOURCES

- The projected loads used in all the Phase 1 studies showed an increase of 3,477 MW between 2013-14 and 2024-25 and an 8,420 MW increase from 2024-25 to 2044-45.
- To meet this load increase in the Phase 1 studies, resources were added during each forecast period. From 2014-15 to 2024-25, the majority of the load increase was met by renewables, primarily wind generation (2,563 MW). During the period 2025-26 through 2044-45, the majority was met through thermal generation (6,932 MW), with the remainder generally being met by wind (1,050 MW).
- The seasonal shape (month to month) of firm loads, imports/exports, and thermal resources is very important yet highly uncertain. The net result of these loads and resources is the Residual Hydro Load, which has a direct effect on the Canadian storage operation and the Canadian Entitlement.

4.3. LONG-TERM PLANNING (AOP)

- Called Upon flood control was assumed to be implemented in short-term and real-time planning and operations rather than in long-term planning such as the AOP. Therefore, flood control in this section does not refer to implementation of, or impacts from, Called Upon flood control requests.
- There were minor changes to the AOP operating criteria because of the use of Canadian local flood control rule curves. Grand Coulee’s flood control curve was adjusted for Canadian power draft in the AOP, resulting in some impact on Canadian storage operation, but negligible impact on annual U.S. generation (+1 aMW). However, the change in monthly generation pattern is noticeable. This estimate of impacts may be an effect of the limited analysis, so the procedure needs to be reviewed in future studies. In general, the post-2024 flood control changes did not have a major impact on the AOP or DDPB modeling.
- On average, there were only minor differences in the monthly generation and operating criteria among scenarios A1, A2, and C, because the loads and resources were adjusted using imports/exports to produce the same Residual Hydro Load. The minor differences were due to the different flood control URCs used in each scenario. Other scenarios and factors that may change this Residual Hydro Load will need to be considered in the future to ensure an optimum power operation and to assess the impacts on the AOP and DDPB (see section 5).

4.4. DETERMINATION OF DOWNSTREAM POWER BENEFITS – CANADIAN ENTITLEMENT

- Based on the assumptions used, the Phase 1 studies indicated that Canadian Entitlement energy decreased from 472 aMW in 2025 to a minimum value of approximately 290 aMW by about 2040, as shown on Table 4-1. The Entitlement capacity increased from 1340 MW to 1524 MW, primarily due to a change in the length of the critical period.

Table 4-1 – Phase 1 Results for Canadian Entitlement

	AOP 14	C-2025	A-2025	C-2045
Entitlement Energy (aMW)	506	472	468	290
Entitlement Capacity (MW)	1340	1320	1320	1524

- The primary factors affecting the Canadian Entitlement Energy are the amount of load growth and type of new resources, especially the mix of thermal and renewable resources. There is a high level of uncertainty associated with these parameters. Less load growth and more renewable resources would reduce the need for thermal installations, and having less thermal generation would actually increase the Canadian Entitlement energy.
- A high degree of uncertainty remains regarding the future amount and value of the Canadian Entitlement and the operation of the hydro system. As the system transitions from an energy-deficit system to a capacity-deficit system, there could be different operating policies, such as maximizing FPLCC or average energy, or operating to market price or certain flows and reservoir elevations.

4.5. RESERVOIR IMPACTS

- Implementation of procedures to make effective use of U.S. storage caused the U.S. projects to draft substantially deeper during Called Upon years compared to current flood control operations.
- As shown on Table 4-2, implementation of effective use of U.S. projects with the maximum flow objective at 450 kcfs caused Grand Coulee to draft empty 28 to 30 times out of 70 years. Under the Treaty Continues with pre-2024 flood control (FCOP), only 4 years out of 70 required Grand Coulee to draft empty.

Table 4-2 – Called Upon Years vs. Years Grand Coulee at 1208 ft on April 30

	C2025 AOP	A1F600	A1F450	B1F600	B1F450	B2F600	B2F450
Total Called Upon Years		21	52	21	52	21	52
Years Grand Coulee is on Empty April 30	4	10	29	10	30	9	28

- Implementation of effective use of U.S. projects caused occasional refill failures (3 years at Libby, 6 at Hungry Horse, and 7 at Dworshak, but Grand Coulee refilled in all 70 years). While power draft of Canadian composite storage provided flood control benefits to the U.S., the Canadian reservoir elevations under either a Flex operation (A1) or a power operation (B2) often did not provide enough draft at Arrow for U.S. flood control.
- The Phase 1 studies examined Treaty planning and modeling as they pertain to power and flood control; however, impacts and results for many U.S. reservoirs were not necessarily representative of how the projects are actually operated because most U.S. reservoirs also include operations for fish and other non-power uses. Similarly, Canadian Flex operation for the Phase 1 studies was developed based on the current load-resource balance, market conditions, and other factors without any consideration of non-power and other environmental needs. If additional evaluations of the Treaty future and the impacts to U.S. reservoirs are undertaken, it is recommended that these evaluations consider applying non-power requirements to the results of the Phase 1 studies (see section 5).

4.6. ARROW PLUS DUNCAN OUTFLOWS

- Without a coordinated Treaty operation, the outflows from Arrow plus Duncan were more uncertain. Further work is needed to understand these uncertainties (see section 5).
- The Treaty is Terminated (B2) scenarios were intended to simulate a possible Canadian power operation. In this operation, Arrow plus Duncan outflows (without Called Upon implementation) were relatively constant across the year compared to the A1 Treaty power operations in order to minimize spill and maximize generation at Arrow. In comparison to Treaty Continues (A1), there was less flow in the winter and summer and more flow in spring.
- For the Treaty is Terminated studies (B2), the Arrow plus Duncan outflows mimicked the outflow shape of the Treaty Continues studies (A1) only when Called Upon was implemented, which required additional draft in the winter and less outflows during the refill period in the spring.
- In the Treaty is Terminated scenarios (B2), the reduction of Arrow plus Duncan outflows in August caused Grand Coulee to draft during the month and never recover toward full during the fall and early winter in most years. In the Treaty Continues scenarios (A1 and C), draft of Canadian projects for power maintained flows from Arrow during this period and allowed Grand Coulee to remain fuller.

4.7. GENERATION IMPACTS

- In the Treaty Continues scenarios (A1), the coordinated U.S./Canada assured power drafts provided substantial flood control benefits to the U.S., including more certainty and less additional volume of Canadian storage required as a direct result of a Called Upon flood control request.
- Overall, in the Treaty is Terminated scenarios (B2) the average annual energy production in Canada and the U.S. remained essentially unchanged in comparison to the A1 studies;

however, the monthly shape differed dramatically from the coordinated operation found in the Treaty Continues scenarios.

- On average, the B2 scenarios shifted generation from high-value winter months to low-value spring freshet months, with the exception of Called Upon years where the flood control Called Upon operation reshaped the generation into the winter and out of the spring.
- On average, the Canadian generation impacts due to Called Upon flood control operations were relatively small compared to their total generation. Actual impacts to the Canadian operation will be highly dependent on the Canadian real-time power (both energy and capacity) and non-power needs and market conditions.
- Under the Treaty is Terminated scenarios (B2), the ability of the U.S. hydro system to meet firm loads in the critical water year diminished by approximately 225 aMW. In addition, the Critical Period was shortened from 4 years to 1 year, which may be of concern during prolonged low inflow conditions.

5. RECOMMENDATIONS FOR FUTURE STUDIES

5.1. INTRODUCTION

While the Phase 1 studies provided valuable information and knowledge about the modeling and evaluation of various post-2024 Treaty and Called Upon scenarios, they also generated as many questions as they answered. From the beginning of this effort, the Phase 1 studies were designed to be the initial steps toward understanding some of the implications of the post-2024 provisions on power and flood control. However, it was clear as work progressed that other possible approaches, assumptions, alternatives, and scenarios would need to be considered for future studies and phases. This section describes some of the areas and issues that were discussed for possible future consideration. There is, however, no commitment at this time by the Entities to conduct such studies or to work jointly in conducting any additional studies.

The following discussions have been grouped into two categories. Section 5.2 deals primarily with how to model and approach various issues. It is focused on modeling techniques, procedures, and implementation. Section 5.3 addresses possibilities for expanding the focus of the Phase 1 studies by examining influences and uncertainty beyond the focus of the original studies.

5.2. PROCEDURES AND METHODOLOGIES

5.2.1. CALLED UPON FLOOD CONTROL

As described in this report, a number of modeling methods and procedures were developed and used in the Phase 1 studies to evaluate the alternative scenarios. Lessons were learned regarding the use of those methods that can be applied to any future studies and possibly to implementation of Called Upon operations after 2024. In summary, the Called Upon procedures as used in the Phase 1 studies will need to be refined, or an entirely new procedure may be developed in any future studies.

5.2.1.1. Called Upon Trigger

For future studies of Called Upon flood control operations, the concept of using a predetermined maximum flow objective and how that objective may be used to calculate Called Upon storage requirements will need to be reevaluated. It is possible that a trigger may be developed that is not directly tied to the flow objective. For example, a higher trigger runoff volume may be selected based on examination of results of the Phase 1 studies. The Called Upon trigger runoff volume may be tested in forecast studies to see the resulting performance. Given forecast runoff volume and inflow shape uncertainty inherent in forecast studies and real operations, it is assumed that the system cannot reduce flows to below 450 kcfs in all years. While it can reduce flows to below 600 kcfs more often than to 450 kcfs, there are infinite possibilities of hydrologic occurrences that are not captured in the 70-year period studied. We therefore cannot say that the system will always be able to be regulated to a maximum flow of 600 kcfs. We also note that there are differences between the Entities with regard to interpretation of Called Upon rights and obligations, including flood control objectives.

5.2.1.2. Canadian Called Upon Draft Volume

The Corps concluded that the Called Upon draft procedure used in the Phase 1 studies frequently drafted Canadian reservoirs deeper than needed for flood control. In order to be able to operate the system to a regulated peak flow at The Dalles that is closer to the maximum peak flow objective, a procedure will need to be developed to reduce Called Upon draft volumes when Called Upon is triggered, and to increase the trigger runoff volume so that Called Upon is not triggered as frequently. The goal will be to deviate from planned Canadian operations as little as possible. Based on the preliminary studies, future studies will refine draft volume requirements by changing the sliding scale using appropriate flood risk analysis studies. A new Called Upon SRD may be required for implementing the Called Upon procedure.

5.2.1.3. Priority of Drafting Canadian Projects

For purposes of meeting flood control objectives at The Dalles, Arrow is the most effective Canadian reservoir for reducing flows, because the response time from Arrow to The Dalles is shorter than from Mica and Duncan to The Dalles. However, the local flood control needs at Revelstoke and downstream of Arrow can usually be met by the assumed power draft operation at Mica (generally, operating Arrow reservoir at elevation 1442 feet, two feet from full, is adequate to dampen the daily flow fluctuations). The priority of which Canadian reservoir to draft first under Called Upon varied between the scenarios.

Further evaluations are needed to determine the allocation of flood control space between Canadian reservoirs that will cost-effectively meet flood control needs while also considering other project purposes.

5.2.1.4. Return of Canadian Projects to Planned Operation After Called Upon

After 2024, the U.S. will be required to reimburse Canada for any operating costs and economic losses incurred whenever Called Upon flood control operations are implemented. Therefore, a critical element of Called Upon implementation will be clearly defining when that action is initiated and when it has been concluded and the Canadian reservoirs have been returned to their planned operations. In the Phase 1 modeling, the Canadian reservoirs returned to their planned operation as soon as possible by releasing minimum flow. In real operations, this may or may not be desirable, depending on the project purposes at the time of the return. For future studies to develop implementation of Called Upon operations, it would be necessary to clearly define procedures for returning Canadian projects to planned operation after Called Upon and criteria for documenting when Called Upon operation is initiated and completed, as well as defining what is meant by economic loss in the Treaty.

5.2.1.5. Runoff Volume Forecast Changes in Called Upon Years

In some years, the runoff volume forecasts fluctuated from month to month above and below the runoff volumes that trigger Called Upon flood control operations. The resulting flow fluctuations may be undesirable for purposes other than flood control, such as fish operations. Refinements in how Called Upon is implemented for years when forecasts are close to the trigger runoff volume need to be developed to reduce highly fluctuating outflows. It may be possible to develop a sliding scale runoff volume trigger to be used such that the smaller the difference of the forecast runoff volume to the trigger runoff volume, the less the reservoirs will draft in January or wait until February to initiate drafting. However, this trigger could cause other problems, such as causing undesirable high flows at The Dalles if a winter flood event were to occur. Future studies could include a range of alternatives to be evaluated with an objective of reducing the flow fluctuations, and discuss tradeoffs between those alternative approaches.

5.2.1.6. Establish Strategies for Prioritizing Between Winter and Spring Flood Control

Modeling to control for winter flood events was not a primary objective for the Phase 1 studies; however, it was discovered that by regulating projects using the assumptions that were developed, Called Upon drafts increased flows to what might be considered undesirable high levels in the winter period. In future studies, strategies for Called Upon flood control operations could prioritize between 1) reducing winter flood flows caused by Called Upon drafts in addition to winter rain events and 2) operating to meet Called Upon draft requirements for spring flood risk management.

5.2.1.7. Canadian Local Flood Control

The daily Canadian Local Flood Control operations provided by BC Hydro for the Phase 1 studies do not take into account power and non-power requirements or necessarily reflect the project physical limitations. Future studies should likely improve the accuracy and reflect the operational capability of the projects.

5.2.1.8. Called Upon Operations and Flex Operations Impacts

In scenarios where the Treaty continues after 2024, Canada may flex operations between Arrow and Mica (shift storage of water between reservoirs) subject to maintaining the same border flow. A cursory evaluation of impacts of Called Upon and Flex operations on each other shows that physically it could be possible to transition from a Flex operation to a Called Upon operation. However, having Mica on minimum flow for up to three months in winter poses a high risk to BC Hydro power reliability and may impact non-power requirements. Further investigation is required on how much Flex operation can impact the Called Upon operation.

5.2.1.9. Knowledge and Assurance of Canadian Operations

If the Treaty is terminated, and without other agreements for coordination of the Columbia River operations, the U.S. will have greater uncertainties in planning for flood risk management operations. The greater the degree of assured future Canadian power drafts, the greater the ability the U.S. will have to manage flood risk, especially the ability to reduce the risk of flooding even in moderate runoff volume years. For effective flood risk management, the U.S. needs a forecast throughout the year of the planned Canadian reservoir operations. In future studies, and under the assumption the Treaty is terminated after 2024, the U.S. will need to make estimates of various scenarios of likely Canadian operations and assess risks and consequences of various scenarios, developing operating criteria based on those assessments.

5.2.1.10. Drafting of all Effective Storage at Related U.S. Projects

Only the U.S. headwater projects (Libby, Dworshak, Hungry Horse) that currently have defined SRDs were operated to the effective use procedure. Grand Coulee and Brownlee reservoirs were drafted toward empty in a year when Called Upon was triggered. It is possible that other projects may also be able to provide some degree of flood protection, but this possibility should be investigated in the future.

5.2.1.11. Economic Loss and Canadian Operating Costs of Called Upon

The Phase 1 studies did not attempt to develop methods or procedures for calculating operating costs and economic loss associated with Called Upon operations after 2024 or to estimate those costs under the Phase 1 scenarios. In addition, no attempt was made beyond modeling assumptions to develop criteria for identifying when a formal Called Upon operation begins to affect Canadian reservoir operations and when those operations have returned to normal. Such criteria will be essential for accounting for the costs of Called Upon. Agreement between the Canadian and U.S. Entities as to acceptable methods, procedures, and criteria will be critical to evaluating the benefits and costs of future Called Upon alternatives and to finalizing implementation of Called Upon operations.

5.2.2. Ongoing Corps of Engineers Flood Risk Assessment

As noted in previous sections, significant additional evaluation beyond the Phase 1 studies is required to fully understand the potential implications of post-2024 Treaty changes on flood control operations in the Columbia River Basin and to further develop procedures for implementing Called Upon flood control in a manner consistent with the Treaty. In support of the U.S. Entity, the Corps of Engineers has initiated a comprehensive Flood Risk Management study. Only the initial phase of that effort, called Flood Risk Assessment (FRA), has been scoped in any detail. The Corps initiated work on the FRA phase of studies in 2009 and plans to complete it in 2011. The objective of FRA is to collect and update data and develop models and other analytical tools needed to evaluate flood risk under existing and base conditions. It is expected that the updated information may be used to evaluate the flood risk associated with alternative approaches to future implementation of Called Upon; however, alternatives beyond those evaluated in Phase 1 have not been formulated at this time. FRA will include the collection of existing information to calculate damages currently prevented in floodplain areas of the Columbia River and tributaries influenced by Treaty storage. The ultimate objective of the FRA is to collect and manage data and information and develop the tools necessary to produce quantifiable estimates of flood control benefits and costs associated with alternative Treaty scenarios.

The Phase 1 studies followed deterministic approaches to evaluating future Called Upon flood control operations. In accordance with U.S. policies and guidance,[33] future flood risk management studies conducted by the Corps will attempt to follow more probabilistic, risk-based approaches to studying system flood management. The ultimate goal of this risk-based evaluation is to complete a comprehensive approach in which the values of all key variables, parameters, and components of flood damage reduction studies are subject to probabilistic analysis. The risk analysis should concentrate on the uncertainties of the variables having a significant impact on study conclusions. At a minimum, the following variables must be explicitly incorporated:

- The stage/damage function for economic studies, with special emphasis on first floor elevation, depth-percent damage relationships, and structure and content values for urban areas
- Discharge associated with exceedance frequency for hydrologic studies
- Structural and geotechnical performance of existing structures

Global climate change considerations are critical to development of the base condition and evaluation of alternatives. Regional expertise should be used to determine climate change conditions "most likely to occur," which then will need to be incorporated into the base condition. Assumptions regarding potential variations in climate change could be tested in various alternatives. Other considerations that will be critical to accurately defining "base condition" for a flood risk management perspective include estimates of future population growth and development in the floodplain.

Based on the findings and conclusions of the Phase 1 studies and other related evaluations, a number of preliminary assumptions can be drawn regarding considerations that should be incorporated into formulation and evaluation of flood risk management scenarios for further study.

The Phase 1 studies looked at a narrow range of flood control strategies that focused on Canadian Storage. In order for the U.S. to determine the most cost-effective solutions for flood control in the U.S. after 2024, alternatives that compare and contrast Called Upon Canadian storage against other flood risk management measures must be evaluated. Other measures may include local flood control improvements (e.g., levee upgrades), changes to operation of U.S. storage facilities, additional U.S. storage, and others.

5.2.3. Capacity Credit Limit

The Treaty defines an Entitlement capacity maximum limit based on the difference in Firm Load Carrying Capability (FLCC)[34] of the Base System and thermal installations with and without

[33] Engineer Regulation (ER) 1105-2-101 (January 3, 2006); Risk Analysis for Flood Damage Reduction

[34] Firm load carrying capability (FLCC) is either the firm energy or firm peak load carrying capability (whichever is critical).

Treaty storage. Using current procedures, the limit is much greater than the forecast Entitlement capacity for 2024-25 and 2044-45 and therefore is not an issue in the Phase 1 studies. However, as loads grow and an increasing amount of renewable resources are added, the region is likely to transition from an energy-deficit to a capacity-deficit system. This will require changes to procedures for determining FLCC and reserves that may cause the CCL to apply. There will also be many questions on how the system should be operated during and after the transition to a capacity-constrained system and what the power objective should be.

5.2.4. Additional Power Studies

The Phase 1 studies did not look closely at optimizing the operating criteria through critical period studies, refill studies, or other analysis. Future studies could explore methods to optimize FLCC and secondary energy production. In addition, other areas that were not considered or analyzed in detail in the Phase 1 studies were alternative scenarios for loads and resources, ability to meet peak loads, system reliability, the value of power, and the tradeoffs between power and non-power objectives.

5.3. SCENARIOS

5.3.1. Non-Power and Non-Flood Control Uses

Analysis of the benefits and impacts associated with the alternative scenarios described in the Phase 1 studies was strictly limited to the two primary purposes authorized under the Treaty—power generation and flood control. No attempt was made to evaluate the future effects of the Phase 1 scenarios on other operating purposes and benefits of the Columbia River system, including but not limited to fisheries, wildlife habitat, recreation, irrigation, water supply, water quality, and navigation. The Canadian and U.S. Entities recognize that evaluation of the potential impacts of system operations on these other operating purposes will be a critical consideration for future phases of study conducted under the Columbia River Treaty Review. The U.S. and Canada will seek input from regional interests, stakeholders, and sovereigns to define these additional scenarios for analysis.

5.3.2. Climate Change – Physical Impacts

The potential effect of global climate change on river hydrology and the benefits and operations of the Columbia River system in Canada and the U.S. is an important regional consideration. Both nations have initiated joint and independent evaluations of the potential impacts of climate change on the timing and volume of precipitation in the Columbia River Basin. Evaluations of possible impacts on reservoir system operations have not been incorporated into the Phase 1 studies but could be considered in any future Columbia River Treaty Review studies.

5.3.3. Climate Change – Green Energy

Part of the climate change picture is the physical system changes (e.g., streamflows, temperature) discussed above; however, another important aspect of climate change is the role of hydropower in the resource portfolio of the region. Regional and national policy is emphasizing clean and renewable resources as part of the resource mix for the future. If minimizing the carbon impact of thermal generation is the primary objective, then maximizing hydropower energy production would require significant changes to Canadian and U.S. project operations. In addition, other renewable resources, such as wind, affect the calculation of the DDPB, the resulting Canadian Entitlement, and operation of the hydro system in the AOP. Examining the role of hydropower and the Treaty in the overall picture and approach to reducing carbon emissions for the future may be another facet of future modeling.

5.3.4. Ranges of Uncertainties

Capturing the uncertainty surrounding all aspects of the future is perhaps the biggest challenge in understanding the post-2024 Treaty world. For example, the Phase 1 studies used one set of assumptions for loads and resources for all scenarios. Future work may include performing sensitivity studies assessing the impact of changes in the loads and resources mix in the AOP, which can affect Canadian storage operation and the Canadian Entitlement. Another example is looking at additional scenarios to assess border flows absent the Treaty. The Phase 1 studies looked at two scenarios with emphasis on power generation and flood control, which did not explore the entire range of possibilities. These are just a few examples of additional scenarios that could be looked at in future studies.