Status Report

Work to Date on the Development of the VARQ Flood Control Operation at Libby Dam and Hungry Horse Dam

January 1999

Section 4

The Effects of VARQ at Libby and Hungry Horse On Columbia River System Hydropower

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1. Introduction

This report describes the impacts to the Pacific Northwest regional power system, and projects within this system, caused by modifying the flood control requirements at Libby and Hungry Horse reservoirs. This modified flood control regulation is called VARQ and was designed to improve the multi-purpose operation of the reservoirs.

Modifying the flood control requirements at Libby and Hungry Horse may affect the capability of the regional power system in a number of ways. The first is in its capability to generate energy and the costs of generating this energy. The second is in its ability to provide capacity and the costs of providing this capacity. Changes in the regional power system's ability to provide these products and the costs of providing these products, is the core of this power system impact analysis.

1.1 The Scope and Purpose

The purpose of this report is to describe the impacts to the Pacific Northwest regional power system, and projects within this system, resulting from modifications in the flood control requirements at Libby and Hungry Horse reservoirs. The report documents impacts in hydropower energy and capacity as well as the costs of providing these products. The report covers only changes resulting from the implementation of the VARQ flood control regulation at Libby and/or Hungry Horse reservoirs.

1.2 Prior Studies

Numerous prior related studies have been conducted to evaluate the hydropower impacts of various types of changes in flood control requirements at these projects. Beginning in 1995 as part of the Columbia River System Operation Review, studies have been conducted to consider the hydropower impacts of various forms of the VARQ flood control requirements. Since 1995, there have been several variations on this concept and the impacts of many of these have been investigated.

1.3 General Hydroregulation Assumptions

The Pacific Northwest reservoir system, including the Snake and Columbia Basins, was modeled using the Corps' Hydro System Seasonal Regulation (HYSSR) model. The base condition analysis in this study relied on the base condition defined in the Corps' Lower Snake Juvenile Migration Feasibility Study.

The model observed operating year 1996-97 project operating limits as submitted to the Pacific Northwest Coordination Agreement (PNCA) planning process. The Canadian storage was operated to fixed reservoir elevations developed in accordance with the AOP97, as modified by the DOP97. The model was run in continuous mode utilizing a 60-year period of historical water conditions, from 1 August 1928 through 31 July 1988. The Regulated Hydro projects are found in Table18 at the end of this document. These projects are those that are regulated within the HYSSR model. The Hydro-Independent projects are based upon PNCA data submittals and are found in Table19. The Hydro-Independent projects are not included in the HYSSR model simulations.

The 60 years of Modified Streamflows used are from "Modified Streamflows, 1990 Level of Irrigation", dated July 1993. They contain 1990-level irrigation depletions. Adjustments to these 1990 level modified stream flows were made due to the Bureau of Reclamation's (BOR's) updated Grand Coulee pumping schedule for the Columbia Basin Project. This pumping schedule is included in the BOR's February 1, 1996 preliminary PNCA data submittal. More assumptions are found in the description of alternatives in Section 2.

1.4 Power Study Assumptions

Analysis of power system impacts was based upon output from the HYSSR hydroregulation model. Output from this model provided the changes in the energy generated by individual projects as well as the changes in the total system. The changes in the average monthly hydro energy generation and plant capabilities were determined by comparing the generation and plant capabilities for each alternative with the corresponding generation and plant capabilities from the appropriate base case. For example, output for Alternatives 3, 5, and 7 was always compared with output for the Alternative 1 base case, because these were all based on the 1995 BiOp operation. Similarly, output for Alternatives 4, 6, and 8 was always compared with output for the Alternative 2 base case, because these were all based on the Sturgeon Recovery Plan operation.

1.4.a Energy

The cost of generating the energy produced by the system was determined using the PC-SAM system production cost model. This model is designed to dispatch electrical generation resources of the Pacific Northwest (PNW) to serve power loads in the PNW, and secondarily, the Pacific Southwest (PSW). Power loads and resources were inputted to the model on the same time period basis used in the HYSSR hydroregulation studies.

Rather than running the PC-SAM model for each alternative evaluated under this study, a set of "generalized" energy values was determined with the model for each month of the year. This was done by running the model under a base condition with all power generating resources available, and then making an alternate run for each month in which a fixed amount of hydropower energy was removed from the system of available resources. The increased system production costs due to the reduced hydropower energy production were then divided by the average megawatts of energy removed to determine an average energy value in dollars per megawatt-hour. These average energy values assumed a 35-year period of analysis and were based on the current Federal interest rate of 7.125% at a 1996 price level. The 1996 price level was used because that was the last time the input data to the model was updated and the differences would be very slight for this data compared to data updated to 1998 price levels.

For power dispatch purposes, system hydropower, independent hydropower (the hydropower projects in the region that are not included in the HYSSR model), and must-run thermal power generation resources, are dispatched as single blocks rather than as individual plants. Variable thermal resources are dispatched one plant at a time on the basis of variable costs, with the least-cost resources being dispatched first.

The PNW hydro/thermal power system, as modeled in PC-SAM, operates to first meet PNW regional loads (firm load first, followed by non-firm load) and then to export all economic resources (resources with a lower variable cost than the PSW marginal resource variable cost) to the PSW. This is done up to the limits of the capacity of the Pacific Northwest-Pacific Southwest (PNW-PSW) Intertie. Exports to the PSW are reduced by 10 percent to account for line losses, which are experienced by the Intertie system. Loads, including exports to the PSW, are served by dispatching resources in the following sequence:

- Must-run thermal resources (dispatched as a single block)
- Combined system and independent hydropower resources (dispatched as a single block)
- Remaining PNW thermal resources (dispatched a plant at a time, in order of increasing cost)

Assumptions regarding specific input data used in the model are listed below:

- Pacific Northwest Load Forecast: The source of information used in the model was the 1995 BPA Pacific Northwest Loads and Resources Study (Whitebook), medium average monthly load projections. Data for three load years was utilized, 1996, 2002, and 2007. Year 1996 was selected to compare to recent market conditions. Years 2002 and 2007 were selected to provide an indication of changes in values over time. To provide loads for 2007, the 1995 BPA Whitebook loads for 2005 (the last year of the projections) were extrapolated based on the average annual growth in load over the previous 5 years. The medium average loads used for the three load years analyzed are shown below in Table1.

Table 1. Regional Firm Loads, BPA 1995 Whitebook, Medium Load Forecast (MW)

	1996 Loads		2002 Loads		2007 Loads
15-Aug	19,974		20,516		21,380
31-Aug	19,974		20,516		21,380
Sep	19,499		20,022		20,882
Oct	20,195		20,711		21,579
Nov	22,207		22,713		23,599
Dec	23,736		24,267		25,176
Jan	24,397		24,938		25,766
Feb	23,299		23,868		24,698
Mar	21,949		22,507		23,317
15-Apr	20,681		21,216		21,995
30-Apr	20,681		21,216		21,995
May	20,067		20,599		21,387
Jun	20,037		20,575		21,360
Jul	20,227		20,775		22,814

- Thermal Power Generating Resources: PC-SAM breaks PNW thermal resources into two categories, the must run thermal and other thermal. The must run plants are coalfired plants with low variable costs that are operated continuously except for periods of required shut down for maintenance. Also included is the one nuclear plant, WNP#2. The operation of these must run thermal plants in PC-SAM do not vary by alternative, so their costs are not included in the PC-SAM runs.

The sources of information used for the monthly generation for all thermal resources were files obtained from BPA showing projected monthly generation by thermal resource for several years in the future. This information was entered into the model in terms of increasing variable cost. The variable costs in the data provided by BPA include real fuel cost escalation (RFCE). In accordance with Corps policy prohibiting use of RFCE in power value analysis, RFCE was removed from this data.

The existing thermal power generating resources combined with hydropower generation will not be sufficient to meet the future load growth under the 50 years of different water conditions. Therefore PC-SAM requires that additional thermal resources be identified to meet this additional load. The cost of generation from these new plants can be considered to reflect two types of production costs; new plants that would be built to meet PNW load deficits, or a proxy of the purchase price for energy from existing PSW plants that would be used to meet PNW loads. The variable costs for these plants were based on information provided by the Federal Energy Regulatory Commission (FERC) and were adjusted to recent natural gas prices. The variable Operation and Maintenance (O&M) costs provided by FERC were used directly.

In order to compute the fuel component of the variable costs, the heat rate and costs of fuel for the plants were required. Details on assumptions used to derive each of these are provided below:

- Heat Rates: An examination of heat rates provided by various sources was undertaken in order to determine the most appropriate value to use. The heat rates provided by FERC were 8,000 Btu/kWh for combined cycle (CC) plants and 12,500 Btu/kWh for combustion turbine (CT) plants. Reports from the Energy Information Administration (EIA) were also examined since they provided the current heat rates of all plants in the United States. For CC plants, it was found that the FERC heat rate of 8,000 Btu/kWh was less than the national average of existing plants, but more (less efficient) than that of new plants. Since the additional plants used to meet load in the PC-SAM model represent new plants to be built in the PNW as well as existing plants in the PSW that will provide some energy to the PNW, the FERC value of 8,000 Btu/kWh was used for CC plants. Similarly, the FERC value of 12,500 Btu/kWh was used for CT plants even though the newest plants have heat rates averaging about 11,800 Btu/kWh.
- Fuel Costs: Natural gas is currently the primary fuel being utilized by CC and CT plants. The value of fuel used by FERC to define energy costs of these additional CC and CT plants was $2.27 per million BTU. This value was considerably higher than the rates currently being contracted for by utilities throughout the west. Based on a review of gas rates, it was decided to use a value of $1.60 per million BTU rather than the $2.27 value provided by FERC. In accordance with Corps policy, no real fuel cost escalation was used for future years.

Using the monthly energy values from the PC-SAM model and the changes in energy generation from the HYSSR model, the changes in the annual cost for operating the entire Pacific Northwest power system were determined. The results of this analysis are described in Section 3.

1.4.b Capacity

The ability of the hydro system to provide capacity may also be affected by the modification of flood control requirements at Libby and Hungry Horse. The ability of the hydro system and the individual projects within the system to provide capacity was based upon analysis of the monthly instantaneous capacity that could be provided under adverse water conditions. The adverse water condition used in this study was the 8-month critical period from September 1936 to April 1937 that is currently being used in power planning studies within the Pacific Northwest. This year was selected to estimate the regional hydro capacity because it approximates the hydro peaking capability that is consistent with the power system criteria set forth in PNCA. Available capacity was analyzed for three different conditions to investigate the range of potential impacts. These were: (1) the January 1937 peak power demand period and critical water period, (2) the September 1936 to April 1937 critical period, and (3) the average for all 60 water conditions.

The changes in the capacity cost for the various alternatives were determined based on the changes in the available capacity and the value of the capacity. The determination of the changes in the available capacity is described in the previous paragraph. The value of the capacity was based upon the capital cost of additional resources that would have to be built to supply the capacity that is lost due to the implementation of the VARQ flood control operation.

The most likely thermal power generation alternative that was determines to replace the lost capacity is a mixture of combined cycle and simple combustion turbine plants. The mixture of resources that was used is about 80% combined cycle plants and 20% combustion turbine plants. The capacity value for the thermal alternative was computed by the Federal Energy Regulatory Commission (FERC) using procedures developed as part of an interagency work group on hydropower evaluation. The value determined using these procedures was $64/kW-yr.

2 Alternatives Investigated

Eight alternatives were considered in this analysis. The first two alternatives were known as the Base Condition and the Future Base Condition. The remaining alternatives are variations on either of these two and involve changes in the flood control requirements at Libby and/or Hungry Horse reservoirs. Descriptions of these alternatives are found below, and the results are presented in Section 3.

The focus of this study concentrated on the differences in generation resulting from variations in flood control storage reservation diagrams. More discussion on the development of this flood control can be found in Section 3 of the main report. Below is a summary of the data files used which contain storage reservoir diagrams used at both Hungry Horse and Libby.

Table 2. Libby and Hungry Horse Flood Control

Alternative Number	Libby - Storage Reservation Diagram	Hungry Horse - Storage Reservation Diagram
Alternative 1	LIBSYS01.SRD	HGHSYS02.SRD
Alternative 2	LIBSYS01.SRD	HGHSYS02.SRD
Alternative 3	LIBSYS04.SRD	HGHSYS02.SRD
Alternative 4	LIBSYS04.SRD	HGHSYS02.SRD
Alternative 5	LIBSYS04.SRD	HGHSYS04.SRD
Alternative 6	LIBSYS04.SRD	HGHSYS04.SRD
Alternative 7	LIBSYS04.SRD	HGHSYS05.SRD
Alternative 8	LIBSYS04.SRD	HGHSYS05.SRD

2.1 Alternative 1 (Base Condition)

Load

All Firm Energy Load Carrying Capability (FELCC) is taken from the 1997 Operating Year (OY97) Critical Period study run by the Northwest Power Pool (NWPP). The NWPP study has a one-year critical period (September 1, 1936 through April 30, 1937). Thus, only one year of FELCC values are used for all water conditions. This study reflects coordination between PNCA parties in meeting PNCA FELCC. Therefore, generation from projects owned by non-PNCA parties (Brownlee, Oxbow and Hells Canyon) will not be used to meet PNCA FELCC in these studies. August, May, June and July FELCC will come from the PNCA Final Regulation, which include flow augmentation target flows at McNary and Lower Granite. FELCC will be created by adding Hydro-Independent generation (see Table20) from 1936-37 to compute system total generation. Then, the system total generation will be reduced by 60 years of hydro-independent generation to produce 60 years of FELCC. The secondary market limit was set at 9,000 MW.

Flood Control

This study uses Upper Rule Curves (URC) or flood control, calculated by using observed volume runoff. The upper rule curve file was created for the February 1, 1998 PNCA Data Submittal by the Corps. The data incorporates shift of system flood control from Dworshak and Brownlee (when the April-July volume forecasts are less than 3.2 Maf and 5.8 Maf, respectively) to Grand Coulee and incorporates the 2.08 Maf Mica and 5.1 Maf Arrow flood control allocation. Flood control will take precedence over all non-power requirements, except International Joint Commission (IJC) 1938 Order at

Kootenay Lake.

Variable Energy Content Curves (VECC's) are calculated using OY97 Power Discharge Requirements (PDR's), distribution factors and forecast errors which are used in PNCA planning. Canadian storage project operations are fixed as described below. The volume forecast for all projects are based on actual runoff.

Critical Rule Curves (CRC) used are in accordance with PNCA 1997 adopted system critical rule curves. They are as follows: 1st year = OY97 CRC1; 2nd year = OY95 CRC3; 3rd year = OY94 CRC4; and 4th year = empty.

<u>Start Elevations</u>

Storage reservoirs are initialized to be full on 1 August 1928, with the following exceptions: Mica is initialized to July Mica target, Grand Coulee is initialized to 1285.0 feet, Brownlee is initialized to 2069.0 feet, Libby is initialized to 2449 feet; John Day is initialized to 262.5 feet, Corra Linn is initialized to 1743.32 feet, Hungry Horse is initialized to 3550 feet and Dworshak is initialized to 1520.0 feet.

<u>Non-Power Requirements</u>

All project non-power requirements will follow those from PNCA plant data book updated 30 Sept 1996 or which were submitted for OY97 PNCA planning process on the February 1, 1996, except as noted within this specification.

<u>Canadian Storage</u>

Mica, Duncan and Arrow will be on their 1997Assured Operating Plan (AOP97) operations including changes agreed to by the Entities as described in the 1997 Detailed Operating Plan (DOP97). The Canadian storage projects are fixed to the operation resulting from the 60-year Detailed Operating Plan (DOP) Treaty Storage Regulation. This 60-year operation was prepared by the COE for use in the PNCA studies. This regulation incorporates the Arrow Total method of computing VECC.

<u>Libby</u>

Libby is operated in September through December to meet December URC (2411.0 feet). In January through mid-April, Libby is operated on minimum flow or flood control objectives as defined in the 1995 BiOP. It should be noted, Libby can violate URC for Corra Linn's IJC operation. Libby is operated mid-April through July for protection of Sturgeon in all but 20% of the worst observed April-September volumes at Libby by supporting Bonners Ferry minimum flows. Sturgeon releases were not provided in 1928-29, 1930-31, 1935-36, 1936-37, 1939-40, 1940-41, 1943-44, 1944-45, 1969-70, 1977-78, 1978-79 and 1987-88. Objectives include: April 16th through 30th, increase flows at Libby so that Bonners Ferry flow is at 15,000 cfs on May 1st (AP2 average flow will vary by water year); May 1st through 19th, minimum flow at Bonners Ferry is 15,000 cfs; May 20th through June 30th, maximum flow at Bonners Ferry is 35,000 cfs;

July 1st through 21st, minimum flow at Bonners Ferry is 11,000 cfs; and July 22nd through 31st, minimum flow at Libby of 4000 cfs. Libby's maximum outflow from mid-April through August is powerhouse hydraulic capacity without spill. In July, mid-August and August, Libby can be operated to as low as elevation 2449, 2439 and 2439 feet to contribute to flow augmentation at McNary. During years when sturgeon releases are not provided, Libby will support McNary flow targets. Libby will operate on minimum flow or flood control January through mid-April. Libby will support McNary flow targets in the last part of April, May, June, July, August 15 and August down to elevation 2420, 2420, 2439, 2449, 2439 and 2439 feet, respectively.

Hungry Horse

Hungry Horse may be operated in proportional draft mode September through December subject to draft limits of 3531, 3526, 3521 and 3515.0 feet, respectively. The reservoir storage-elevation relationship will reflect 3% bank storage. From January through March, Hungry Horse is free to operate above its Biological Rule Curves (see Table21) objectives as defined in the 1995 BiOP (Calculated according to instructions in the 1996-97 PNCA Operating Procedures). In April through June, Hungry Horse operates on or near flood control. On April 30, May 31, June 30, July 31, August 15 and August 31, Hungry Horse draft limit is 3540, 3540, 3540, 3550, 3540 and 3540.0 feet for McNary flow augmentation. Hungry Horse will be operated to support the Columbia Falls minimum flow of 3,500 cfs year round and maximum flow of 4,500 cfs October 15 through December 15. Hungry Horse maximum outflow from mid-April through August is powerhouse hydraulic capacity plus 3,000 cfs spill.

Albeni Falls

Albeni Falls is operated in September to 2060.0 feet. In October through April, Albeni Falls is operated to 2055.0 feet. In May, Albeni Falls is operated to 2057.0 feet. In June through August, Albeni Falls is operated to full (2062.5 feet).

Grand Coulee

Grand Coulee is operated to meet FELCC September through December subject to draft limits of 1280, 1280, 1275 and 1265, respectively. In January through mid-April, minimum storage values are calculated for Grand Coulee Biological Rule Curves (see Table21) which reflect the expected April 15th URC and storage needed for the appropriate Vernita Bar minimum flow requirement. Grand Coulee is then operated above these minimum storage points. From mid-April through May, Grand Coulee may be drafted to the lower of flood control or 1250 feet to support McNary flow augmentation objectives. In June, Grand Coulee may be drafted to the lower of flood control or 1280 feet to support McNary flow augmentation objectives. July, mid-August and August, Grand Coulee may be drafted as low as 1285, 1280.0 and 1280.0 feet to support McNary flow augmentation objectives. At-site minimum flow is equal to 30,000 cfs. Grand Coulee is subject to a drawdown limit of 1.3 feet per day.

Vernita Bar minimum flows for December through may vary by water condition, with minimum flows established as the lesser of a) 68% of the Wanapum's October or November flows or b) 70,000 cfs. Values less than 70,000 cfs are rounded to the nearest 5,000 cfs. The minimum protection level flow at Vernita Bar will be 50,000 cfs.

Snake River Projects

The Upper Snake reservoir operations adjustments to Brownlee inflows came from the BOR in May 1997. The operation tries to release 427 kaf in as many years as possible over the 60-year record during the May through August period.

Brownlee will be on flood control from February through April. In May, the reservoir is operated to 2069 feet or lower if required for flood control. In June, Brownlee is filled if necessary and maintained at elevation 2077 feet. In July, August 15 and August 31, the reservoir is drafted to 2069 feet, 2050 feet and 2048 feet, respectively for flow augmentation which includes both IPCO contribution and shaping of Upper Snake water by the end of August. In September and October, the reservoir operates to 2050 feet and 2048 feet, respectively in anticipation of providing a maximum discharge of 9,000 cfs from mid-October through November. Outflows up to 20,000 cfs are allowed in October (the average of 30,000 cfs in the first half and 9,000 cfs in the second half of the month). No higher than 9,000 cfs is allowed in November. By the end of December and January, the reservoir is operated at 2070 feet and 2060 feet respectively.

Dworshak is on minimum flow of 1300 cfs all periods or flood control objectives as defined in the 1995 BiOP, with the exception of April through August when it operates to meet Lower Granite flow augmentation objectives. Dworshak may draft to elevation 1520 feet by August 31 to support Lower Granite flow augmentation objectives. Note: Dworshak's outflow is limited to 14,000 cfs during the flow augmentation period (mid-April through August) and is limited to 25,000 cfs in all other periods for downstream flood control. This operation is described in the February 1, 1996 PNCA data submittal.

Fishery Operations

The four lower Snake River projects (Lower Granite, Little Goose, Lower Monumental and Ice Harbor) and the four lower Columbia River projects (McNary, John Day, The Dalles and Bonneville) each are required to operate their turbines within 1% of peak efficiency during the period of March through November.

Generation at these eight projects (Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, The Dalles and Bonneville) is reduced further with the inclusion of Juvenile Bypass Fish Spill as reflected in the 1995 BiOp. If the regulated outflow at Lower Granite is less than 100 kcfs then there is no spill at the project; otherwise, spill will be 80 percent of instantaneous flow at Lower Granite. If the regulated outflow at Lower Granite is less than 85 kcfs, there is no spill at Little Goose and Lower Monumental; otherwise, spill will be 80 and 81 percent of instantaneous flow at Little Goose and Lower Monumental, respectively. Bonneville has a daytime spill cap of 75,000 cfs from 0600 to 1800 hours. Juvenile Bypass Fish Spill at Federal projects (percent of outflow), limited by Spill Caps, is as shown below. The spill caps represent completed modifications at spillways currently planned and which are used as hydroregulation modeling caps, not instantaneous.

Table 3. Federal Juvenile Bypass Fish Spill in Percent of Regulated Flow

	MAR	AP1	AP2	MAY	JUN	JUL	AG1	AG2	CAP(cfs)
BONNEVILLE	.230		.499	.680	.680	.770	.770	.770	100000
THE DALLES			.469	.640	.640	.640	.640	.640	230000
JOHN DAY			.121	.165	.165	.430	.430	.430	60000
ICE HARBOR		.108	.270	.270	.413	.700	.700	.700	60000
MCNARY			.183	.250	.250				60000
LOWER MONUMENTAL		.162	.405	.405	.270				20000
LITTLE GOOSE		.160	.400	.400	.267				25000
LOWER GRANITE		.160	.400	.400	.267				22500

A sliding scale flow augmentation objective was used from 220,000 to 260,000 cfs at McNary based on The Dalles April 1, January through July volume runoff. A straight-line interpolation was used for flow objectives for volume forecasts between 85 and 105 Maf in the April 20 through June period. AP2 values are prorated at 4 days at 155,000 cfs and 11 days at from 220,000 to 260,000 cfs. Maximum and minimum objectives are 260,000 cfs and 220,000 cfs, respectively. July and August flow objectives are 200,000 cfs. The priority for releasing water from upstream reservoirs for flow augmentation is Grand Coulee, Libby and Hungry Horse. The first priority is to support objectives and secondly to fill by June 30.

Lower Granite also has sliding scale flow augmentation objectives. When the April 1 Lower Granite April through July runoff forecast is less than 16 Maf, then the mid-April through June 20 flow objective is 85,000 cfs and the June 21 through August flow objective is 50,000 cfs. When the April 1 Lower Granite April through July forecast is greater than 20 Maf, then the mid-April through June 20 target flow is 100,000 cfs. When the April 1 Lower Granite April through July forecast is greater than 28 Maf, then the June 21 through August target flow is 55,000 cfs. The spring flow objectives are interpolated for forecasts between 16 and 20 Maf and the spring flow objectives are interpolated for forecasts between 16 and 28 Maf. The first priority is to support objectives and secondly to fill by June 30.

John Day is operated at 262.5 feet from mid-April through September. From October through mid-April, John Day operates to elevation 265 feet.

Lower Snake projects will be operated at MOP in accordance with the COE data submittal and the 1995 BiOp. As identified in the 1995 BiOp, the Corps will operate Little Goose, Lower Monumental, and Ice Harbor within one foot of minimum operating pool (MOP) during the period from approximately April 10 through August 31. Lower

Granite will operate within one foot of MOP from approximately April 10 through November 15. MOP for Lower Granite, Little Goose, Lower Monumental and Ice Harbor are elevation 733, 633, 537 and 437 feet, respectively. During the rest of the year, Lower Granite, Little Goose, Lower Monumental and Ice Harbor will operate at elevation 738, 638, 540 and 440 feet, respectively.

Juvenile Bypass spill at non-Federal projects will be as described below and as was submitted for OY97 PNCA planning.

Table 4. Non-Federal Project Spill for Fish in Percent of Regulated Flow

PROJECTS:	Apr1	Apr2	May	Jun	Jul	Aug1	Aug2	SPILL CAP
Wells	0.0	6.5	6.5	0.0	6.5	2.5	0.0	10 kcfs
Rocky Reach	0.0	12.0	15.0	4.0	8.0	4.0	0.0	5 kcfs
Wanapum	0.0	10.0	25.0	2.5	14.2	20.0	1.25	10 kcfs
Priest Rapids	0.0	7.0	35.0	5.8	13.5	20.0	6.3	25 kcfs

MONTH	PERIOD AVERAGE SPILL
Rock Island-	
April 1-15	4,800 cfs
April 16-30	19,300 cfs
May	23,000 cfs
June	23,000 cfs
July	23,000 cfs
August 1-15	19,300 cfs
August 16-31	4,800 cfs

<u>Kootenay Lake Operation</u>

Kootenay Lake shall be operated as necessary, up to free flow, to maintain the lake level below the IJC rule curve and the calculated "allowable elevation at Queens Bay". This is implemented using the 5-step method as developed by BPA and the Corps. After August 31, the lake level may be raised to elevation 1745.32 at the Queens Bay gage. This maximum elevation at Queens Bay is in effect through January 7. After January 7, the lake will be lowered to elevation 1744 on February 1, elevation 1742.4 on March 1, and 1739.32 on April 1. April through August 31, after the lake exceeds elevation 1739.32 feet at the Queens Bay gage, the lake shall be operated using the "allowable elevation" calculation to determine the Queens Bay maximum allowable elevation until the elevation at the Nelson gage drafts back to elevation 1743.32 feet.

2.2 Alternative 2 (Future Base Condition)

Since the base condition is evolving and has different non-power requirements introduced every year, the alternative flood control measures were also compared to a likely future base condition. In the most likely future base condition, the Sturgeon

Recovery Plan flows were used to develop the Libby operation. The Sturgeon Recovery Plan flows are as shown in Table2. and were provided in every year. The 1995 BiOp sturgeon flows are described on page 11. This is the only difference between Alternative 1 and 2.

Table 5. Expected Minimum White Sturgeon Flows at Bonners Ferry - cfs

	May 1 Runoff Volume Forecast for the period Apr-Sep at Libby					
Period	>=9.5 Maf	8.50 to 9.49	7.08 to 8.49	6.40 to 7.079	5.04 to 6.34	<= 1.00
May 1	4.00	4.00	4.00	4.00	4.00	4.00
May 15	24.77	20.26	13.48	9.42	7.61	5.81
Jun 1	50.00	40.00	25.00	16.00	12.00	8.00
Jun 30	50.00	40.00	25.00	16.00	12.00	8.00
Jul 15	27.74	22.58	14.84	10.19	8.13	6.06
Jul 31	4.00	4.00	4.00	4.00	4.00	4.00

2.3 Alternative 3 (Base Condition with Libby VARQ)

In Alternative 3, the Libby flood control in the Base Condition (Alternative 1) was replaced with the VARQ flood control at Libby. This allowed the system resources to be reregulated to respond to the new flood control. This resulted in different regulated flows, ending reservoir elevations and generation. These differences were used to evaluate the system generation impacts compared to the current base condition, Alternative 1.

2.4 Alternative 4 (Future Base Condition with Libby VARQ)

In Alternative 4, the Libby flood control in the likely Future Base Condition (Alternative 2) was replaced with the VARQ flood control at Libby. This allowed the system resources to be reregulated to respond to the new flood control. These differences were used to evaluate the system generation impacts compared to likely future base condition, Alternative 2.

2.5 Alternative 5 (Base Condition with Libby and Hungry Horse VARQ)

To understand the impacts to the power system with VARQ at both Libby and Hungry Horse, the flood control in the Base Condition (Alternative 1) was replaced with the VARQ flood control at these two projects. These differences were used to evaluate the system generation impacts compared to base condition, Alternative 1.

2.6 Alternative 6 (Future Base Condition with Libby and Hungry Horse VARQ)

In the likely future base condition, the impacts to the power system with VARQ at both Libby and Hungry Horse were evaluated by replacing the flood control in the likely Future Base Condition (Alternative 2) at these two projects. These differences were used to evaluate the system generation impacts compared to likely future base condition, Alternative 2.

2.7 Alternative 7 (Base Condition with Libby and Hungry Horse Modified VARQ)

The Hungry Horse VARQ flood control data used in Alternatives 5 and 6 was prepared by the Corps of Engineers. The Bureau of Reclamation reviewed the Corps VARQ flood control and recommended some changes to the computations. The resulting VARQ flood control for Hungry Horse is known as "Modified VARQ." Since these changes may be implemented they were evaluated the same as the alternatives described above.

In the base condition, the impacts to the power system with VARQ at both Libby and Hungry Horse were evaluated by replacing the flood control in the Base Condition (Alternative 1) at these two projects. At Hungry Horse, the Modified VARQ flood control was used. The differences were used to evaluate the system generation impacts compared to the base condition, Alternative 1.

2.8 Alternative 8 (Future Base Condition with Libby and Hungry Horse Modified VARQ)

To understand the impacts to the power system with VARQ at both Libby and Hungry Horse, the flood control data in the likely Future Base Condition (Alternative 2) was replaced with the VARQ flood control at these two projects. At Hungry Horse the Modified VARQ flood control was used. The differences were used to evaluate the system generation impacts compared to likely future base conditions, Alternative 2.

3 Comparison of Alternatives

This section of the report will compare and contrast the alternatives. The primary information presented will be the changes in the capability of the system and projects within it to generate energy and provide capacity and the costs of generating this energy and providing this capacity.

Results from the Hydroregulations are summarized in Tables B-22 through B-25. Tables B-22 and B-23 show Libby 60-year average end-of-month elevation and discharge, during each period for 8 alternatives investigated. The 60-year end-of-month elevation and discharge for each alternative investigated are shown in Tables B-24 and B-25.

3.1 Reservoir Operation

3.1.1 Comparison of the Base Condition (Alternative 1) vs. the Likely Future Base Condition (Alternative 2)

The 60-year average ending elevation at Libby for the Base Condition in July was El. 2444.1 feet, 6 feet below the likely Future Base Condition. The Future Base Condition 60-year average ending elevation was 2450.3 feet. This is because the recovery plan volume of sturgeon flow augmentation is considerably less than the 1995 BiOp flows.

The difference in 60-year average regulated flow during the sturgeon flow augmentation is shown below. The 1995 BiOp results in very high regulated flow from Libby in June where the Recovery plan augmentation is more distributed over the May, June and July period. The remainder of the year discharges from Libby were 3,000 cfs more with the recovery plan augmentation, except in January and February, which is 4,000 cfs less than the 1995 BiOp.

Table 6. Libby 60-year Average Regulated Flow - cfs

Alternative	Apr 15	Apr 30	May 31	Jun 30	Jul 31
Alt 1, 1995 BiOp	5,804	8,649	9,858	22,554	7,725
Alt 2, Recovery Plan	5,572	11,348	13,857	12,625	17,079

Hungry Horse operated almost the same in both the base Condition and the Future Base Condition with the Future base Condition less than one foot lower. Discharges were within 1,000 cfs during the year. In July, the 60-year average elevation did not change between the two studies.

3.1.2 Comparison of Base Condition (Alternative 1) vs. Libby VARQ Flood Control (Alternative 3)

When compared to the Base Condition, the 60-year average ending elevation in July at Libby is 6 feet higher when the VARQ flood control is utilized. This is consistent with the VARQ flood control, which is generally higher than existing flood control. From August through December, the average ending elevations are the same. During the flood control evacuation period, the reservoir ending elevation was, at the deepest point, 20 feet higher with the VARQ flood control. Through the sturgeon flow augmentation period, the flows were the same, but after this period in July and August the flows were 4,000 cfs higher when using VARQ at Libby.

Hungry Horse operated the same both with (Alt 2) and without Libby VARQ flood control (Alt 1).

3.1.3 Comparison of Future Base Condition (Alternative 2) vs. Libby VARQ Flood Control (Alternative 4)

When comparing Libby VARQ to the likely Future Base Condition, the impacts were less significant because the recovery plan flow augmentation is less than the 1995 BiOp. At the end of July, the 60-year average ending elevation at Libby is only 1 foot higher than the Base Condition when the VARQ flood control is utilized. From August through December, the average ending elevation is the same. During the flood control evacuation period, the reservoir ending elevation was, at the deepest point, 10 feet higher with the VARQ flood control. The flows over the operating year were within 2,000 cfs of the Future Base Condition.

Hungry Horse operated the same both with and without Libby VARQ flood control.

3.1.4 Comparison of Base Condition (Alternative 1) vs. Libby and Hungry Horse VARQ Flood Control (Alternative 5)

In this alternative, Libby operated similar to Alternative 3 where the VARQ flood control was substituted for the Base condition flood control.

At Hungry Horse, the Base Condition flood control was replaced with VARQ flood control. During August through December, the operation was similar to the future base condition. Through the flood control evacuation and refill period, the ending elevation of the reservoir was higher than the future base condition when implementing the VARQ flood control. The end of July 60-year average elevation was 3552 feet, the same as the future base condition. Discharges from Hungry Horse were within 1,000 cfs with the exception of April 15 and April 30 which were 1,000 and 4,000 cfs less, respectively. This is because the VARQ flood control does not draft the project as deep during April.

3.1.5 Comparison of Future Base Condition (Alternative 2) vs. Libby and Hungry Horse VARQ Flood Control (Alternative 6)

In this alternative, Libby operated similar to Alternative 4 where the VARQ flood control was substituted for Base Condition flood control at Libby.

At Hungry Horse, the Base Condition flood control was replaced with VARQ flood control. During August through December, the operation was similar to the Base Condition. Through the flood control evacuation and refill period, the ending elevation of the reservoir was higher when implementing the VARQ flood control. The end of July reservoir 60-year average elevation was 3552 feet, the same as the Base Condition. Discharges from Hungry Horse were within 1,000 cfs with the exception of April 30, which was 4,000 cfs less. This is because the VARQ flood control does not draft the project as deep during the last half of April.

3.1.6 Comparison of Base Condition (Alternative 1) vs. Libby VARQ and Hungry Horse Modified VARQ Flood Control (Alternative 7)

After the Corps prepared VARQ flood control for Hungry Horse, the Bureau of Reclamation reviewed the information and recommended some changes to the flood control. Alternatives 7 and 8 utilized this modified VARQ flood control at Hungry Horse.

In this alternative, Libby operated similar to Alternative 3 where the VARQ flood control was substituted for the Base condition flood control.

At Hungry Horse, the Base Condition flood control was replaced with VARQ flood control. During August through December, the operation was similar to the future base condition. Through the flood control evacuation and refill period, the ending elevation of the reservoir was higher than the future base condition when implementing the VARQ flood control. The end of July 60-year average elevation was 3552 feet, the same as the future base condition. Discharges from Hungry Horse were within 1,000 cfs with the exception of April 30, which was 3,000 cfs less. This is because the VARQ flood control does not draft the project as deep during April.

3.1.7 Comparison of Future Base Condition (Alternative 2) vs. Libby VARQ and Hungry Horse Modified VARQ Flood Control (Alternative 8)

In this alternative, Libby operated similar to Alternative 4 where the VARQ flood control was substituted for Base Condition flood control at Libby.

The average discharge from Hungry Horse is within 1,000 cfs in all periods with the exception of April 30 when the Base Condition flood control was replaced with VARQ flood control. During August through December, the operation was similar to the Base Condition. Through the flood control evacuation and refill period, the ending elevation of the reservoir was higher when implementing the modified VARQ flood control as compared to the Base Condition and the Corps' VARQ flood control. The end of July reservoir 60-year average elevation was 3552 feet, the same as the Base Condition. Discharges from Hungry Horse were within 1,000 cfs with the exception of April 30, which was 3,000 cfs less than Alternative 1. This is because implementation of the Bureau of Reclamation modified VARQ drafts the reservoir more than the Corps VARQ flood control during the last half of April.

3.2 Energy Generation

This section compares the monthly hydropower generation in average megawatts, averaged over the 60 water years, for each alternative evaluated. Results are shown for the entire hydro system as well as the subsystem of Canadian projects including Mica Revelstoke, Corra Linn, Kootenay Canal Plant, Kootenay Plants (Upper Bonnington, Lower Bonnington, and South Slocan), Brilliant, Seven Mile, and Waneta. The results for each alternative are shown in a table with the corresponding base condition the alternative is based upon.

In general, the energy analysis results shown below in Tables B-4 through B-7 indicate that there is an overall increase in average monthly and total annual hydro system energy generation for all alternatives. Alternative 5 has the largest gain in energy generation, while Alternative 4 has the smallest gain. The changes in generation were smaller for Alternatives 4, 6, and 8 than they were for Alternatives 3, 5, and 7. This reflects the fact that the Future Base Condition (Alternative 2) incorporates smaller amounts of storage for sturgeon flows, and therefore the generation is changed less by the implementation of VARQ than the current base condition (Alternative 1). The same general trends were observed for the subsystem of Canadian projects.

Throughout the year there are fluctuations in the energy generated, and for all of the alternatives there is a decrease in the energy generated during the winter period from about January through early April compared to the base cases. Although reservoir elevations at Libby and Hungry Horse tend to be higher during these months, the energy generation decrease is due to lower releases that occurred during this period under the alternatives with the VARQ operation. During the fall, spring, and summer periods, there is an increase in the energy generated. These same trends in energy generation occur for the subsystem of Canadian projects.

Table 7. Monthly Energy from Hydro System Generation for Alternatives Compared to Alternative 1 (Base Condition) in average MW

	Alt. 1	Alt. 3	Difference	Alt. 5	Difference	Alt. 7	Difference
15-Aug	16,697	17,291	594	17,306	609	17,309	612
31-Aug	14,138	14,552	414	14,597	459	14,598	460
Sep	11,934	12,086	152	12,076	142	12,075	141
Oct	11,917	11,933	16	11,943	26	11,943	26
Nov	13,019	13,036	17	13,036	17	13,041	22
Dec	17,000	16,976	-24	16,970	-30	16,956	-44
Jan	19,488	19,132	-356	19,119	-369	19,147	-341
Feb	17,660	17,199	-461	17,226	-434	17,207	-453
Mar	16,385	16,187	-198	16,228	-157	16,179	-206
15-Apr	17,501	17,443	-58	17,415	-86	17,420	-81
30-Apr	19,134	19,228	94	19,050	-84	19,080	-54
May	21,488	21,494	6	21,454	-34	21,444	-44
Jun	21,869	21,901	32	21,916	47	21,916	47
Jul	16,977	17,397	420	17,534	557	17,543	566
Average	16,784	16,798	14	16,805	21	16,803	19

Table 8. Monthly Energy from Canadian Hydro Subsystem Generation for Alternatives Compared to Alternative 1 (Base Condition) in average MW

	Alt. 1	Alt. 3	Difference	Alt. 5	Difference	Alt. 7	Difference
15-Aug	3,548	3,666	118	3,668	120	3,668	120
31-Aug	3,319	3,386	67	3,390	71	3,390	71
Sep	2,497	2,515	18	2,505	8	2,504	7
Oct	2,407	2,403	-4	2,411	4	2,411	4
Nov	2,612	2,610	-2	2,609	-3	2,614	2
Dec	2,927	2,923	-4	2,926	-1	2,924	-3
Jan	2,703	2,645	-58	2,643	-60	2,645	-58
Feb	2,424	2,333	-91	2,338	-86	2,333	-91
Mar	2,549	2,526	-23	2,527	-22	2,524	-25
15-Apr	2,623	2,619	-4	2,619	-4	2,620	-3
30-Apr	2,373	2368	-5	2,363	-10	2,362	-11
May	2,760	2,763	3	2,764	4	2,763	3
Jun	3,042	3,041	-1	3,044	2	3,044	2
Jul	3,190	3,227	37	3,234	44	3,235	45
Average	2,753	2,750	-3	2,751	-2	2,751	-2

Note: Canadian hydro subsystem consists of Mica, Revelstoke, Corra Linn, Kootenay Canal Plant, Kootenay Plants (Upper Bonnington, Lower Bonnington, and South Slocan), Brilliant, Seven Mile, and Waneta.

Table 9. Monthly Energy from Hydro System Generation for Alternatives Compared to Alternative 2 (Future Base Condition) in average MW

	Alt. 2	Alt. 4	Difference	Alt. 6	Difference	Alt. 8	Difference
15-Aug	17,595	17,614	19	17,650	55	17,665	70
31-Aug	14,596	14,696	100	14,750	154	14,763	167
Sep	12,070	12,087	17	12,086	16	12,087	17
Oct	11,937	11,947	10	11,958	21	11,961	24
Nov	13,030	13,032	2	13,043	13	13,045	15
Dec	17,097	17,133	36	17,101	4	17,107	10
Jan	19,255	19,248	-7	19,274	19	19,267	12
Feb	17,224	17,222	-2	17,254	30	17,226	2
Mar	16,195	16,202	7	16,243	48	16,186	-9
15-Apr	17,450	17,442	-8	17,422	-28	17,412	-38
30-Apr	19,217	19,314	97	19,148	-69	19,195	-22
May	21,659	21,447	-212	21,376	-283	21,357	-302
Jun	21,543	21,559	16	21,564	21	21,575	32
Jul	17,111	17,233	122	17,348	237	17,367	256
Average	16,794	16,802	8	16,810	16	16,807	13

Table 10. Monthly Energy from Canadian Hydro Subsystem Generation for Alternatives Compared to Alternative 2 (Base Condition) in average MW

	Alt. 2	Alt. 4	Difference	Alt. 6	Difference	Alt. 8	Difference
15-Aug	3,672	3,680	8	3,682	10	3,684	12
31-Aug	3,397	3,420	23	3,428	31	3,429	32
Sep	2,522	2,523	1	2,523	1	2,523	1
Oct	2,406	2,407	1	2,411	5	2,411	5
Nov	2,613	2,612	-1	2,612	-1	2,611	-2
Dec	2,942	2,950	8	2,944	2	2,944	2
Jan	2,657	2,656	-1	2,660	3	2,658	1
Feb	2,335	2,334	-1	2,342	7	2,334	-1
Mar	2,528	2,528	0	2,530	2	2,526	-2
15-Apr	2,619	2,619	0	2,620	1	2,619	0
30-Apr	2,393	2387	-6	2,386	-7	2,385	-8
May	2,758	2,754	-4	2,753	-5	2,753	-5
Jun	3,038	3,042	4	3,043	5	3,043	5
Jul	3,193	3,195	2	3,202	9	3,204	11
Average	2,757	2,759	2	2,761	4	2,760	3

Note: Canadian hydro subsystem consists of Mica, Revelstoke, Corra Linn, Kootenay Canal Plant, Kootenay Plants (Upper Bonnington, Lower Bonnington, and South Slocan), Brilliant, Seven Mile, and Waneta.

3.3 Energy Production Costs

As shown below in Tables B-8 through B-11, the energy production costs followed the same general trends as the energy generation results. In these tables, a negative value indicates a cost decrease, while a positive number indicates a cost increase. Although there were fluctuations in the monthly energy production costs, there was a net decrease in the energy production costs for the overall hydro system due to the increased generation that resulted from implementation of the VARQ flood control operation. The fluctuations followed the same trends as the energy generation results, with increased costs in the period from about January through early April due to lower energy generation, and decreased costs the rest of the year when energy generation increased.

The results for the subsystem of Canadian projects showed a slight increase in the energy production costs for Alternatives 3, 5, and 7, and a decrease for Alternatives 4, 6, and 8. The results are due to the fact that the implementation of the VARQ flood control operation had a bigger impact on the existing base condition operation (Alternative 1) than on the future base condition (Alternative 2).

Table 11. Change in Monthly Energy Production Costs from U.S. Hydro Subsystem Generation for Alternatives Based on Alternative 1 (Base Condition) in Millions of 1996 Dollars

	Alt. 3	Alt. 5	Alt. 7
15-Aug	-3.16	-3.25	-3.26
31-Aug	-2.45	-2.74	-2.75
Sep	-1.77	-1.77	-1.77
Oct	-0.28	-0.29	-0.30
Nov	-0.24	-0.26	-0.27
Dec	0.26	0.38	0.53
Jan	4.30	4.47	4.08
Feb	4.77	4.48	4.66
Mar	2.38	1.84	2.46
15-Apr	0.31	0.48	0.45
30-Apr	-0.57	0.44	0.25
May	-0.02	0.39	0.49
Jun	-0.24	-0.34	-0.33
Jul	-4.96	-6.64	-6.75
Average	-0.20	-0.27	-0.25
Total	-1.70	-2.82	-2.52

Table 12. Change in Monthly Energy Production Costs from U.S. Hydro System Generation for Alternatives Based on Alternative 2 (Future Base Condition) in Millions of 1996 Dollars

	Alt. 4	Alt. 6	Alt. 8
15-Aug	-0.08	-0.30	-0.38
31-Aug	-0.55	-0.87	-0.95
Sep	-0.21	-0.20	-0.21
Oct	-0.13	-0.22	-0.26
Nov	-0.04	-0.18	-0.23
Dec	-0.37	-0.02	-0.10
Jan	0.09	-0.23	-0.16
Feb	0.02	-0.30	-0.04
Mar	-0.10	-0.62	0.09
15-Apr	0.05	0.17	0.22
30-Apr	-0.59	0.36	0.08
May	2.11	2.81	3.01
Jun	-0.09	-0.12	-0.20
Jul	-1.55	-2.95	-3.18
Average	-0.08	-0.15	-0.12
Total	-1.45	-2.69	-2.32

3.4 Capacity

The hydro system capacity analysis results shown below in Tables B-15 through B-18 vary depending upon what water conditions are analyzed. The largest decrease in total hydro system monthly instantaneous capacity occurs for Alternative 3 under the adverse water conditions and peak power demands encountered in January 1937. Under these conditions, there is a decrease in hydro system monthly instantaneous capacity of 87 MW compared to the existing base condition (Alternative 1). The average decrease in total hydro system capacity for the critical water conditions from September 1936 through April 1937 is 70 MW for Alternative 3. For these two scenarios of water conditions and power loads, there is no impact from the VARQ under Alternatives 5 and 7. Conversely, when the average system capability is evaluated for all 60 water conditions, there is a net gain for Alternatives 3, 5, and 7. This reflects the fact reservoir elevations and releases under VARQ on average tend to be higher than the current flood control operation.

For Alternatives 4, 6, and 8 that are based on the Future Base Condition (Alternative 2), there is a slight decrease in total system capacity when all 60 water conditions are considered. For these same alternatives, on average, no capacity impact was seen for the cases where the critical water conditions were evaluated. This is due to the fact that the VARQ flood control procedures have less of an impact on the Future Base Condition than they do on the current base condition.

Table 13. Changes in Hydro System Monthly Instantaneous Capacity for Alternatives based on Alternative 1 (Base Condition), in MW

	Alt. 3	Alt. 5	Alt. 7
January 1937	-88	-92	-92
September 1936 – April 37 Critical Period	-70	-71	-71
Average of all 60 Water Conditions	13	13	13

Table 14. Changes in Canadian Subsystem Monthly Instantaneous Capacity for Alternatives based on Alternative 1 (Base Condition), in MW

	Alt. 3	Alt. 5	Alt. 7
January 1937	1	-1	-1
September 1936 – April 37 Critical Period	0	0	0
Average of all 60 Water Conditions	0	0	0

Table 15. Changes in Hydro System Monthly Instantaneous Capacity for Alternatives based on Alternative 2 (Future Base Condition), in MW

	Alt. 4	Alt. 6	Alt. 8
January 1937	0	0	0
September 1936 – April 37 Critical Period	0	0	0
Average of all 60 Water Conditions	-3	-2	-1

Table 16. Changes in Canadian Hydro Subsystem Monthly Instantaneous Capacity for Alternatives based on Alternative 2 (Future Base Condition), in MW

	Alt. 4	Alt. 6	Alt. 8
January 1937	0	0	0
September 1936 – April 37 Critical Period	0	0	0
Average of all 60 Water Conditions	0	0	0

3.5 Capacity Cost

The hydro system capacity costs are shown below in Tables B-17 through B-20. It can be seen that the costs correspond to the changes in capacity described in the previous section. The capacity cost ranges from $5.6 million higher per year for Alternative 3 under January 1937 water conditions to $1 million lower per year for Alternative 5 when the results for all 60 water conditions are averaged.

Table 17. Changes in U.S. Hydro Subsystem Capacity Cost for Alternatives based on Alternative 1 (Base Condition), in Millions of 1996 Dollars

	Alt. 3	Alt. 5	Alt. 7
January 1937	5.79	5.92	5.92
September 1936 – April 37 Critical Period	4.56	4.56	4.62
Average of all 60 Water Conditions	-0.85	-0.85	-0.85

Table 18. Changes in U.S. Hydro Subsystem Capacity Cost for Alternatives based on Alternative 2 (Future Base Condition), in Millions of 1996 Dollars

	Alt. 4	Alt. 6	Alt. 8
January 1937	0.00	0.00	0.00
September 1936 – April 37 Critical Period	0.00	0.00	0.00
Average of all 60 Water Conditions	0.20	0.13	0.07

3.6 Total Cost

The changes in the total regional power costs including energy and capacity changes are shown below in Tables B-19 through B-22. Since these tables show the changes in the total regional power costs, negative numbers indicate a cost decrease, and positive numbers indicate a cost increase. This information is shown for each alternative compared to the appropriate base condition. In all cases, the capacity cost is based upon the results for the 1936-37 critical period. The results show that Alternative 3 would have a cost that is $3.34 million higher than the existing base condition. All other alternatives would have a net decrease in total regional power costs when compared to their respective base conditions.

Table 19. Changes in U.S. Hydro Subsystem Power Costs for Alternatives based on Alternative 1 (Base Condition), in Millions of 1996 Dollars

	Alt. 3	Alt. 5	Alt. 7
Total Annual Energy Production Cost	-1.70	-2.82	-2.52
Hydro System Annual Capacity Cost For 1936-37 Critical Period	4.56	4.56	4.62
Total Cost	2.86	1.74	2.10

Table 20. Changes in U.S. Hydro Subsystem Power Costs for Alternatives based on Alternative 2 (Future Base Condition), in Millions of 1996 Dollars

	Alt. 4	Alt. 6	Alt. 8
Total Annual Energy Production Cost	-1.45	-2.69	-2.32
Hydro System Annual Capacity Cost For 1936-37 Critical Period	0.00	0.00	0.00
Total Cost	-1.45	-2.69	-2.32

4 Summary and Conclusions

This appendix has identified numerous changes that will occur to the projects within the Columbia River Hydropower System and the system as a whole as a result of the implementation of the VARQ flood control operation at Libby and Hungry Horse reservoirs.

With respect to the reservoir operation, the implementation of VARQ generally results in higher reservoir elevations at Libby and Hungry Horse during the flood control evacuation and refill period compared to the current flood control operation. It also results in lower releases during the period from January through March and higher releases during the summer period.

The energy analysis showed that there is an overall increase in the average monthly and total annual hydro system generation for all alternatives compared to the base conditions. There are months in which the generation decreases; however, the overall result is an increase. The energy production cost results show that although there were fluctuations in the monthly costs, there was a net decrease in the energy production costs for the overall hydro system. For the Canadian subsystem of projects there was a slight increase in the energy production costs for Alternatives 3,5, and 7 and a decrease for Alternatives 4,6, and 8.

The capacity analysis results showed that there was a decrease in monthly instantaneous system capacity for Alternative 3 under the September 1936 through April 1937 critical period. When the average system capability is averaged over all 60 water conditions, there is a net gain in monthly instantaneous capacity. For Alternatives 4,6, and 8, there is a slight decrease in total system capacity when all 60 water conditions are considered. There is no capacity impact for these alternatives when critical water conditions were elevated. The capacity cost changes based on monthly instantaneous capacity range from a yearly increase of $5.6 million under Alternative 3 for January 1937 water conditions to $1 million per year lower under Alternative 5 when the results for all 60 water years are considered.

The total cost would increase by $3.34 million per year for Alternative 3 compared to the base conditions based on the 1936-1937 critical period water conditions. All other alternatives would result in a net decrease in total regional power costs for VARQ when compared to the appropriate base condition.

Table 21. Regulated Hydroelectric Projects and Control Points

WHITE RIVER
TIMOTHY
CLACKAMAS [1]
UPPER BAKER
LOWER BAKER
ROSS
DIABLO
GORGE
CUSHMAN NO 1
CUSHMAN NO 2
ALDER
LA GRANDE
LIBBY
BONNERS FERRY
DUNCAN
CORRA LINN
KOOTENAY PLANTS
CANAL PLANT
BRILLIANT
MICA
REVELSTOKE
ARROW
HUNGRY HORSE
KERR
THOMPSON FALLS
NOXON
CABINET GORGE
PRIEST LAKE
ALBENI FALLS
BOX CANYON
BOUNDARY
SEVEN MILE
WANETA
POST FALLS
UPPER FALLS
MONROE STREET
NINE MILE
LONG LAKE
LITTLE FALLS
GRAND COULEE
CHIEF JOSEPH
WELLS
CHELAN
ROCKY REACH
ROCK ISLAND
WANAPUM
PRIEST RAPIDS
BROWNLEE
OXBOW
HELLS CANYON
DWORSHAK
LOWER GRANITE
LITTLE GOOSE
LOWER MONUMENTAL
ICE HARBOR
MCNARY
JOHN DAY
ROUND BUTTE
PELTON & REREG
THE DALLES
BONNEVILLE
SWIFT NO 1
SWIFT NO 2
YALE
MERWIN
MOSSYROCK
MAYFIELD

[1] OAK GROVE, NORTH FORK, FARADAY, RIVER MILL ARE MODELED AS CLACKAMAS.

Table 22. Hydro-Independent Projects

JACKSON
SPPU - Electron, Snoqualmie 1&2, Nooksack
KLAMATH LAKE
JOHN BOYLE
COPCO 1&2
IRON GATE
ROGR - Prospect 14, Eagle Point
LOST CREEK
UMPQ - Lemolo 1&2, Clearwater 182, Toketee, Fish Creek, Slide Creek, Soda Springs
SPPA - Condit, Powerdale, Naches, Naches Drop, Big Fork, Bend, Cline Falls, Wallowa Falls, FALL CREEK
HILLS CREEK
LOOKOUT POINT
DEXTER
COUGAR
GREEN PETER
FOSTER
DEXTER
BIG CLIFF
CARMEN SMITH
TRAILBRIDGE
LEABURG
WALTERVILLE
TW SULLIVAN
STONE CREEK
BULLRUN
COWLITZ FALLS
SPSE - Cedar Falls, Newhalem
MEYERS FALLS
PALISADES
ANDERSON RANCH
SPSI - Black Canyon, Boise R. Diversion, Minidoka
SPBP - Roza, Chandler, Packwood

Table 23. Hydro-Independent Generation -- aMW

	AG1	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	AP1	APR	MAY	JUN	JUL
28-29	667	640	667	777	822	678	644	537	667	746	792	1087	1078	774
29-30	648	600	585	567	545	853	612	1016	715	726	714	790	764	699
30-31	605	575	604	608	674	570	632	604	680	903	684	790	698	616
31-32	531	505	557	611	750	638	769	536	1181	1085	1107	1252	1137	790
32-33	676	634	645	745	1027	852	859	543	729	772	860	1209	1421	972
33-34	757	706	758	866	905	1031	1128	737	755	726	695	711	576	643
34-35	485	479	481	748	1112	1025	868	765	693	807	883	1038	958	690
35-36	600	571	565	648	676	590	1074	632	785	848	1019	1282	1081	768
36-37	644	612	660	625	568	639	496	533	746	1001	1059	1264	1322	826
37-38	650	618	647	760	1101	1089	1070	707	903	976	1294	1360	1017	737
38-39	667	653	689	713	919	917	858	694	860	916	931	1050	890	817
39-40	642	594	618	701	686	831	723	895	1011	915	828	829	664	668
40-41	599	545	611	672	826	778	772	621	599	589	570	756	670	595
41-42	581	563	666	821	921	1094	795	705	623	757	764	919	933	743
42-43	648	609	652	646	1164	1195	1094	917	982	1341	1301	1187	1272	873
43-44	753	739	766	843	940	843	704	676	675	740	759	850	876	767
44-45	642	607	604	641	819	630	875	976	758	849	1049	1428	981	716
45-46	615	612	758	760	1070	1156	1110	759	910	954	1183	1329	1201	866
46-47	707	640	697	857	1135	1208	901	895	856	1063	1027	937	1012	800
47-48	681	643	694	1050	1237	896	1095	776	782	840	1043	1386	1367	852
48-49	738	696	741	885	1003	1024	618	766	1036	1119	1300	1504	1112	885
49-50	715	658	698	870	967	836	967	905	1208	1243	1248	1338	1373	1022
50-51	810	806	792	1093	1354	1303	1239	1207	1029	1224	1157	1272	950	831
51-52	740	735	798	1057	1137	1110	873	981	894	1264	1304	1386	1248	931
52-53	729	716	785	761	757	711	1254	1194	879	838	1005	1378	1329	964
53-54	813	788	810	892	1244	1273	1156	1071	896	1239	1164	1214	1294	1002
54-55	846	829	861	922	982	862	791	725	694	838	816	1229	1336	1028
55-56	759	690	739	976	1271	1284	1243	846	982	1162	1357	1466	1396	988
56-57	796	788	858	1030	1145	1244	824	859	1212	1303	1108	1259	971	817
57-58	665	655	776	838	944	1165	1150	1168	830	854	1206	1259	1177	850
58-59	731	685	768	844	1214	1072	1200	838	843	976	945	1135	970	825
59-60	675	642	887	1016	986	829	687	859	1001	1199	1043	1354	1101	763
60-61	674	645	705	798	1148	954	876	1216	1130	946	873	1170	1006	713
61-62	620	578	657	823	1013	1079	957	763	701	1159	1195	1222	1011	799
62-63	724	674	701	1003	1193	1138	758	1034	810	1034	976	1247	843	771
63-64	647	594	677	768	1147	930	1055	773	768	1009	983	1206	1390	925
64-65	760	742	802	836	974	1300	1256	991	952	940	1078	1135	1004	792
65-66	768	747	745	807	964	803	1012	672	823	1124	1016	1144	923	830
66-67	645	591	647	737	998	1095	1108	863	791	866	851	1126	1147	798
67-68	648	647	646	926	934	914	997	1074	881	681	694	874	819	757
68-69	600	610	807	886	1259	1102	1090	743	791	948	1046	1442	1206	757
69-70	662	613	683	854	905	937	1169	931	844	898	920	1080	934	766
70-71	641	583	675	810	1139	1042	1260	1063	1133	1195	1056	1427	1354	947
71-72	807	770	880	921	1205	1138	1246	1225	1546	1258	1174	1380	1194	987
72-73	800	785	888	855	951	1111	1132	749	714	662	717	886	771	751
73-74	606	568	640	763	1300	1267	1233	949	1159	1333	1181	1347	1378	931
74-75	825	779	778	751	897	1149	1201	899	1004	902	950	1325	1226	973
75-76	771	758	780	957	1211	1286	1290	932	883	969	1032	1229	1042	926
76-77	831	824	776	762	824	663	602	572	608	617	635	872	711	656
77-78	554	534	572	694	1200	1213	990	741	740	759	813	973	806	679
78-79	642	652	793	704	838	906	727	782	984	942	1038	1151	805	694
79-80	580	579	653	666	794	941	1048	771	784	816	979	965	821	691
80-81	573	562	676	621	908	1120	776	808	717	689	747	833	948	705
81-82	620	569	622	751	917	1126	966	1196	1100	1031	1089	1149	1077	854
82-83	714	697	811	914	1042	1191	1229	1021	1114	1103	989	1165	1096	915
83-84	707	769	825	796	1154	1084	1244	948	1100	1138	1061	1286	1268	866
84-85	710	723	864	916	1252	972	847	682	691	980	1062	1155	1053	766
85-86	649	596	737	862	1058	815	998	1138	1211	972	964	1070	862	705
86-87	633	611	777	800	1132	865	887	797	869	759	800	888	724	671
87-88	601	544	576	545	590	832	811	670	753	913	857	1039	978	675
MAX.	846	829	888	1093	1354	1303	1290	1225	1546	1341	1357	1504	1421	1028
MED.	666	641	700	804	992	1024	978	823	850	944	1010	1178	1015	795
AVE.	680	653	714	806	997	987	964	849	884	958	983	1151	1043	807
MIN.	485	479	481	545	545	570	496	533	599	589	570	711	576	595

Table 24. 1996-97 PNCA Minimum Content Curves (BiOp) In Elevation

HUNGRY HORSE (FT)

Year 19__	JAN	FEB	MAR	AP1
29	3528.8	3523.8	3519.6	3520.0
30	3540.5	3535.6	3531.0	3533.7
31	3537.7	3533.3	3529.3	3531.7
32	3496.2	3492.2	3496.0	3501.2
33	3462.5	3456.5	3452.3	3458.6
34	3508.2	3510.2	3513.8	3518.7
35	3512.4	3511.1	3507.9	3509.2
36	3522.2	3516.3	3511.8	3514.0
37	3536.4	3529.9	3523.7	3523.4
38	3521.8	3517.4	3514.1	3517.5
39	3516.5	3510.8	3509.0	3513.2
40	3542.0	3536.6	3533.1	3535.6
41	3560.0	3560.0	3555.9	3557.2
42	3528.7	3525.2	3520.7	3523.6
43	3478.4	3475.9	3474.1	3481.0
44	3555.3	3549.3	3543.4	3543.8
45	3523.8	3518.9	3513.9	3514.4
46	3507.3	3503.3	3501.9	3506.4
47	3485.9	3483.2	3483.7	3489.6
48	3486.4	3481.5	3477.4	3479.6
49	3521.5	3516.1	3511.2	3514.8
50	3449.0	3444.9	3444.6	3451.3
51	3482.2	3484.9	3484.8	3490.2
52	3519.8	3515.6	3511.6	3515.5
53	3496.8	3495.0	3491.7	3494.6
54	3461.4	3456.1	3452.8	3457.5
55	3507.0	3502.7	3498.1	3499.8
56	3486.7	3482.4	3479.2	3484.1
57	3514.3	3509.7	3506.3	3508.3
58	3515.4	3510.2	3506.6	3510.1
59	3439.6	3438.0	3436.9	3446.6
60	3504.6	3501.8	3503.7	3508.1
61	3495.5	3492.9	3492.3	3497.6
62	3501.7	3498.3	3494.2	3499.6
63	3521.9	3521.9	3520.4	3523.3
64	3479.7	3473.3	3467.2	3470.5
65	3471.0	3468.2	3464.4	3471.0
66	3516.0	3511.4	3507.9	3511.8
67	3471.3	3469.2	3466.1	3470.8
68	3500.2	3496.9	3498.8	3502.5
69	3515.9	3512.3	3508.6	3512.7
70	3499.1	3493.5	3488.3	3490.2
71	3456.1	3460.5	3460.3	3466.7
72	3451.2	3444.9	3451.1	3460.2
73	3536.0	3531.8	3527.0	3528.3
74	3437.6	3440.2	3441.7	3451.0
75	3482.3	3476.6	3471.0	3472.3
76	3488.9	3485.6	3482.0	3487.5
77	3558.7	3553.6	3548.1	3548.6
78	3498.0	3492.6	3490.7	3496.2
79	3510.9	3505.8	3503.4	3506.3
80	3527.9	3522.4	3517.5	3517.7
81	3496.0	3495.7	3497.0	3501.8
82	3473.5	3471.6	3471.6	3475.9
83	3516.9	3513.2	3512.6	3515.3
84	3519.4	3517.4	3515.3	3517.8
85	3509.3	3504.6	3500.4	3504.2
86	3519.5	3517.3	3520.1	3523.8
87	3548.0	3543.2	3542.5	3544.8

GRAND COULEE (FT)

Year 19__	JAN	FEB	MAR	AP1
29	1271.3	1277.8	1272.4	1280.2
30	1290.0	1288.7	1282.2	1281.5
31	1290.0	1290.0	1282.9	1281.5
32	1208.0	1208.0	1211.4	1220.0
33	1208.0	1208.0	1209.3	1220.3
34	1208.0	1210.4	1234.9	1246.2
35	1208.0	1208.0	1232.6	1252.4
36	1211.6	1216.3	1234.1	1243.1
37	1290.0	1288.7	1282.2	1280.2
38	1208.0	1208.0	1230.5	1225.9
39	1265.2	1267.9	1274.4	1268.1
40	1290.0	1286.2	1279.2	1273.7
41	1289.3	1285.9	1280.0	1281.9
42	1208.0	1229.8	1251.3	1252.8
43	1208.0	1208.0	1239.1	1232.9
44	1289.7	1280.8	1280.8	1282.2
45	1249.7	1246.8	1252.3	1260.2
46	1208.0	1208.0	1208.0	1218.8
47	1208.0	1208.0	1227.7	1226.3
48	1208.0	1208.0	1208.0	1208.0
49	1208.0	1208.2	1231.2	1233.5
50	1208.0	1208.0	1208.0	1213.0
51	1208.0	1208.0	1223.4	1221.5
52	1208.0	1208.0	1230.4	1225.7
53	1208.0	1208.0	1208.0	1221.0
54	1208.0	1208.0	1208.0	1208.0
55	1208.0	1208.0	1208.0	1211.9
56	1208.0	1208.0	1208.0	1208.0
57	1208.0	1208.0	1215.9	1221.5
58	1208.0	1208.0	1220.4	1222.8
59	1208.0	1208.0	1208.0	1212.1
60	1208.0	1208.0	1229.3	1231.3
61	1208.0	1208.0	1208.0	1217.1
62	1208.0	1208.0	1234.7	1231.9
63	1215.1	1238.8	1256.8	1255.5
64	1208.0	1208.0	1213.5	1217.8
65	1208.0	1208.0	1232.0	1227.8
66	1208.0	1238.4	1258.8	1257.0
67	1208.0	1208.0	1208.0	1210.7
68	1208.0	1227.2	1248.8	1248.9
69	1208.0	1208.0	1212.1	1221.9
70	1215.5	1219.9	1237.6	1237.1
71	1208.0	1208.0	1208.0	1209.5
72	1208.0	1208.0	1208.0	1208.0
73	1272.9	1282.1	1275.0	1281.5
74	1208.0	1208.0	1208.0	1208.0
75	1208.0	1208.0	1221.9	1226.8
76	1208.0	1208.0	1216.4	1223.9
77	1285.2	1279.7	1280.4	1282.5
78	1208.0	1208.0	1228.0	1225.4
79	1279.4	1284.6	1267.5	1268.6
80	1208.0	1211.9	1236.0	1246.8
81	1208.0	1208.0	1231.4	1231.9
82	1208.0	1208.0	1208.3	1218.1
83	1208.0	1208.0	1226.2	1228.8
84	1208.0	1208.0	1218.8	1223.0
85	1230.0	1238.3	1251.0	1250.6
86	1208.0	1229.4	1248.7	1244.3
87	1289.8	1288.1	1281.7	1280.5

88	3544.9	3539.0	3534.1	3536.5

88	1290.0	1290.0	1283.1	1280.4

Table 25. Libby 60-year Average End-of-Month Elevation – ft

	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
Alt. 1	2440.4	2430.9	2429.6	2427.3	2411.9	2385.3	2362.2	2352.6	2355.8	2398.0	2425.2	2444.1
Alt. 2	2441.3	2430.7	2429.4	2426.9	2411.0	2395.2	2381.3	2375.1	2375.5	2406.0	2445.6	2450.3
Alt. 3	2439.5	2430.3	2429.1	2426.9	2411.9	2396.3	2382.6	2376.5	2380.4	2414.3	2439.0	2447.3
Alt. 4	2441.6	2431.1	2429.7	2427.2	2411.0	2395.2	2381.3	2375.1	2377.4	2415.1	2449.2	2451.8
Alt. 5	2439.6	2430.4	2429.2	2427.0	2412.0	2396.4	2382.7	2376.6	2380.6	2414.5	2439.2	2447.4
Alt. 6	2441.3	2430.8	2429.3	2426.8	2411.0	2395.2	2381.2	2374.9	2376.9	2415.0	2449.2	2451.8
Alt. 7	2439.6	2430.4	2429.2	2427.0	2412.0	2396.4	2382.7	2376.6	2380.6	2414.5	2439.2	2447.4
Alt. 8	2441.2	2430.7	2429.3	2426.8	2411.0	2395.2	2381.3	2375.1	2377.1	2415.1	2449.2	2451.8

Table 26. Libby 60-year Average Discharge – cfs

	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
Alt. 1	11723	13044	6446	6216	13268	16554	13138	6744	7227	9858	22554	7725
Alt. 2	15593	13798	6430	6336	13568	11130	9354	5720	8460	13857	12625	17079
Alt. 3	15116	12881	6406	6141	13019	11131	9354	5720	6705	11444	22405	14220
Alt. 4	16421	13751	6507	6368	13760	11130	9354	5720	7623	9437	15413	18528
Alt. 5	15116	12881	6406	6141	13019	11131	9354	5720	6653	11444	22403	14254
Alt. 6	16658	13743	6513	6369	13501	11151	9408	5764	7809	9241	15357	18506
Alt. 7	15116	13682	6499	6141	13019	11131	9354	5720	6653	11444	22403	14254
Alt. 8	16709	13749	6514	6366	13492	11130	9354	5720	7819	9248	15414	18503

Table 27. Hungry Horse 60-year Average End-of-Month Elevation – ft

	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
Alt. 1	3540.4	3533.7	3528.3	3525.9	3517.0	3511.2	3503.7	3496.4	3495.7	3527.4	3547.6	3552.1
Alt. 2	3540.6	3533.8	3528.3	3525.9	3517.1	3509.6	3502.6	3495.6	3494.8	3527.4	3547.3	3552.0
Alt. 3	3540.6	3533.8	3528.3	3525.9	3517.0	3509.6	3502.7	3495.6	3494.6	3527.3	3547.7	3552.1
Alt. 4	3540.6	3533.8	3528.3	3525.9	3517.1	3509.6	3502.7	3495.6	3495.3	3527.4	3546.1	3551.6
Alt. 5	3540.6	3533.8	3528.3	3525.9	3517.0	3509.3	3501.4	3493.7	3501.5	3531.2	3550.3	3552.6
Alt. 6	3540.6	3533.9	3528.3	3526.0	3517.0	3508.9	3501.0	3493.2	3501.2	3531.2	3548.7	3552.1
Alt. 7	3540.4	3533.8	3528.3	3525.9	3516.6	3509.0	3495.7	3496.3	3501.0	3531.4	3550.2	3552.4
Alt. 8	3540.6	3533.9	3528.3	3526.0	3517.0	3509.4	3502.6	3496.1	3501.5	3531.8	3548.9	3552.2

Table 28. Hungry Horse 60-year Average Discharge -- cfs

	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL
Alt. 1	5507	3296	2941	2142	4079	2808	3478	3351	4625	3001	4973	2076
Alt. 2	5389	3312	3005	2121	4091	3273	3330	3272	4615	2753	5103	2005
Alt. 3	5460	3338	2986	2122	4093	3267	3314	3282	4683	2733	4931	2058
Alt. 4	5283	3302	3007	2118	4092	3278	3320	3273	4487	2897	5552	1671
Alt. 5	5627	3338	2985	2116	4104	3360	3611	3307	2100	3403	5386	2886
Alt. 6	5449	3275	3030	2113	4110	3488	3618	3334	2023	3312	5981	2503
Alt. 7	5639	3257	2985	2116	4252	3293	3255	3085	2738	3159	5501	2933
Alt. 8	5480	3269	3030	2119	4110	3327	3256	3082	2723	3146	6151	2543