US Army Corps
of Engineers ®
Portland District

# Salmon Recovery through John Day Reservoir

## John Day Drawdown Phase I Study

## Economic Analysis Technical Appendix Hydropower Operation and Regulations Section






September 2000

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# Section 1. Introduction

This technical appendix section documents the results of the hydropower evaluation for the John Day Drawdown Phase I Study. This Phase I Study is a reconnaissance-level evaluation of the potential consequences and benefits of the proposed drawdown of the John Day Reservoir. This technical appendix section supplements the main report, which describes more fully the alternatives, purpose, scope, objectives, assumptions, and constraints of the study.

# Section 2. Background of the Project

In 1991, the National Marine Fisheries Service (NMFS) proposed that Snake River wild sockeye, spring/summer chinook, and fall chinook salmon be granted “endangered” or “threatened” status under provisions of the Endangered Species Act. Natural resource agencies believe that the drawdown of the 76-mile John Day Reservoir may provide substantial improvements in migration and rearing conditions for juveniles by increasing river velocity, reducing water temperature and dissolved gas, and restoring riverine habitat. It is also speculated that drawdown may improve spawning conditions for adult fall chinook by restoring spawning habitat and the natural flow regimes needed for successful incubation and emergence.

As a result, the NMFS Reasonable and Prudent Alternative Action #5 of its’ Biological Opinion on Operation of the Federal Columbia River Power System (FCRPS), and subsequent reports recommended that USACE investigate the feasibility of lowering John Day Reservoir. In compliance with appropriation conditions, only two alternatives were to be evaluated: reduction of the current water surface elevation 265 to the level of the spillway crest that would vary between elevations 217 and 230, or reduction to natural river level elevation 165. Both alternatives were proposed by NMFS. These two alternatives were then expanded to consider each alternative with 500,000 acre-feet of flood storage and without such storage. Flood storage and hydropower are the current approved authorizations for the John Day project.

# Section 3. Description of the Study Area

The Columbia River originates in Canada and flows for 300 miles through eastern Washington to Oregon and continues west to the Pacific Ocean, as shown in Figure 1. The adjoining region is mostly open country, with widely scattered population centers. The climate of the region is semiarid. Agriculture, open space, and large farms are prevalent. Lands adjacent to the reservoir are used to grow grains and other crops. The reach of the Columbia River under consideration in this report extends from John Day Lock and Dam at river mile (RM) 215.6, to McNary Lock and Dam RM 291. The body of water impounded by John Day Dam, Lake Umatilla, is referred to as the John Day Reservoir throughout this report. The John Day is the second longest reservoir on the Columbia River, extending 76 miles upstream to McNary Dam.

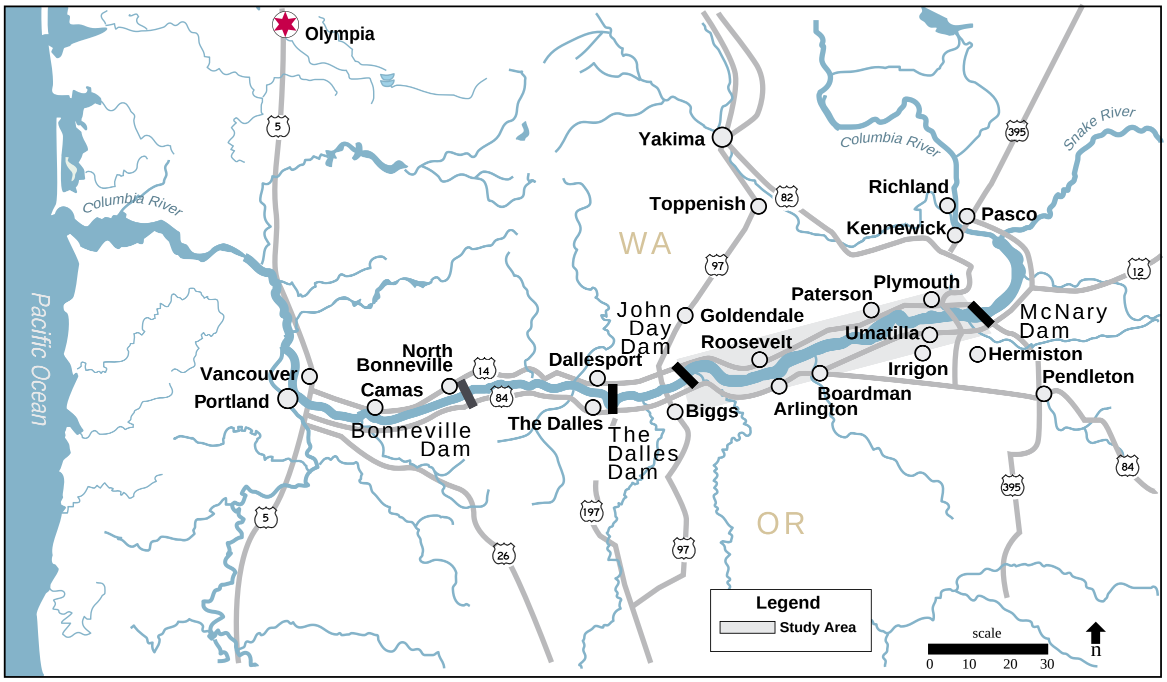



Figure 1. John Day Drawdown Phase 1 Study Area

John Day Dam and Reservoir are part of the Columbia-Snake Inland Waterway. This shallow-draft navigation channel extends 465 miles from the Pacific Ocean at the mouth of the Columbia River to Lewiston, Idaho. The entire channel consists of three segments. The first is the 40-foot-deep water channel for ocean-going vessels that extends for 106 miles from the ocean to Vancouver, Washington. The second is a shallow-draft barge channel that extends from Vancouver to The Dalles, Oregon. Although this section is authorized for dredging to a depth of 27 feet, it is currently maintained at 17 feet. The third section of the channel is authorized and maintained at a depth of 14 feet and extends from The Dalles to Lewiston. In addition to the main navigation channel, channels are dredged to numerous ports and harbors along the river.

The middle Columbia River area is served by a well-developed regional transportation system consisting of highways, railroads, and navigation channels. Railroads and highways parallel the northern and southern shores of the reservoir. Interstate 84 (I-84), a divided multilane highway, runs parallel on the south shore with the Columbia River from Portland, Oregon, to points east. Washington State Route 14 (SR-14) also parallels the Columbia River from Vancouver to McNary Dam on the north shore. Umatilla Bridge at RM 290.5, downstream from McNary Dam, is the only highway bridge linking Oregon and Washington across the Columbia River in the John Day Reservoir.

The study area includes lands directly adjacent to the reservoir as well as those directly and indirectly influenced by the hydrology of the reservoir (e.g., irrigated lands). It includes the reservoir behind the John Day Dam, and adjoining backwaters, embayments, pools, and rivers.

# Section 4. Alternatives

The Phase 1 Study includes a preliminary evaluation of the impacts of the drawdown scenarios relative to the “without project condition,” which is defined as the condition that would prevail into the future in the absence of any new federal action at John Day. The four alternatives are summarized below. One of the most important constraints on the alternatives is the requirement to pass fish for river flows up to the 10-year flood flow of 515,000 cfs. Under the four alternatives, John Day Reservoir would be drawn down at a rate of one foot per day. For greater detail, please refer to the main report, *John Day Drawdown Phase 1 Study*, and *John Day Drawdown Phase 1 Study, Engineering Technical Appendix, Structural Alternatives Section*.

## 4.1. Spillway Drawdown without Flood Control (Alternative 1)

The first drawdown alternative is based on requirements for improved downstream fish passage conditions during both low and flood flow conditions on the Columbia River. The existing 20-bay spillway will be operated differently from current operations, but without any structural modifications. All project inflows will be directly passed through the dam spillway with the spillway gates fully opened in free overflow condition, resulting in a pool elevation that will vary from elevation 217 to 230. Impacts downstream from John Day Dam were not studied.

## 4.2. Spillway Drawdown with Flood Control (Alternative 2)

The second study alternative is based on requirements for improved downstream fish passage conditions during low flow periods, while maintaining authorized flood control for the John Day Project. The existing 20-bay spillway will be operated differently from current operations, but without any structural modifications. During low flow periods, project inflows will be directly passed through the dam spillway with the spillway gates set in fully open, free overflow condition. During a flood event, however, the spillway gates will be controlled to reduce downstream flood flows based on using 500,000 acre-feet of allocated project storage space. Ponding will occur upstream from the dam. Impacts downstream from John Day Dam were not studied.

## 4.3. Natural River Drawdown without Flood Control (Alternative 3)

The third study alternative is based on a natural river drawdown for fish passage “without flood control” condition. Natural river conditions pertain to an opening at the John Day Dam that permits acceptable upstream fish passage conditions. The size of the total dam opening must conform to two criteria based on an invert elevation at the dam of 135. The first criterion is that the opening must be sufficiently large to meet maximum allowable stream velocity criteria for sustained swim speed for the weakest salmon species, which is estimated to be 10 feet per second (fps). The second criterion is that fish passage for this opening must correspond to the 10-year annual flood peak (515,000 cfs). This alternative will require extensive modifications to John Day Dam even beyond modification of the 1,228-foot long spillway structure. Impacts downstream from John Day Dam were not studied.

## 4.4. Natural River Drawdown with Flood Control (Alternative 4)

This fourth study alternative is based on natural river conditions for fish passage and includes the “with flood control” condition. It requires natural fish passage conditions for both upstream and downstream directions at the dam and includes a requirement for full authorized flood control. The calculated width of the total dam opening will correspond to that previously calculated for natural river conditions without flood control (Alternative 3). Impacts downstream from John Day Dam were not studied.

# Section 5. Power System Impacts

The economic analysis of hydropower production impacts was performed to identify the net system economic effects resulting mainly from the reductions in hydropower production at John Day Dam. In addition, net system economic effects are also provided for broader system operating scenarios such as a scenario with both John Day Dam drawn down and the Lower Snake River projects removed.

Columbia River Basin hydropower projects (hereafter referred to as the hydropower system) serve as the major element in the Pacific Northwest (PNW) electrical system. On average, they provide about 60 percent of the total energy generation and 70 percent of the total generating capacity in the region. However, the hydrologic nature of hydropower generation makes it variable from year to year depending on streamflow conditions. In high streamflow years, the amount of hydropower generated can be significantly greater than in the average year.  This additional power serves as a major part of the electricity exports from the PNW.  In low streamflow years, or in high demand periods, power is often imported into the PNW to meet the local power demands (also referred to as loads).  Consequently, any long-term or permanent changes in the level of PNW hydropower production could impact the amount of power bought and sold from the PNW and also the amount of new power generating facilities built throughout the West.  For these reasons, the geographic scope of this analysis spanned the entire western United States and parts of Canada and Mexico as defined by the boundaries of the Western Systems Coordinating Council (WSCC).  The WSCC is one of nine self-governed regional electric power reliability councils that form the North American Electric Reliability Council (NERC).  The WSCC comprises all or part of the 14 western states as well as two provinces in Canada and a small portion of northern Mexico.  It totals over 1.8 million square miles.

This hydropower impact economic analysis was conducted jointly by the staffs of USACE and the Bonneville Power Administration (BPA), the regional federal power marketing agency.  The analysis relied heavily on a similar analysis performed for the *Lower Snake River Juvenile Salmon Migration Feasibility Study (Lower Snake River Study)*.  The Lower Snake River Study used an oversight group to guide the analysis and to provide a forum for interested parties to provide input.  This Hydropower Impact Team (HIT) consisted of 10 to 20 members from numerous interested entities such as USACE, the BPA, the Northwest Power Planning Council, the Bureau of Reclamation, the National Marine Fisheries Service, regional Native American groups, river-use interest groups, and environmental protection groups.  This John Day Dam drawdown analysis used many of the analytical procedures, tools, and basic assumptions that were developed or approved by the Lower Snake River HIT.

The analysis first examined how John Day Dam and the Lower Snake River projects currently function and how their operation would change under the study alternatives.  System hydro-regulation modeling studies were then performed to estimate the hydropower generation impacts associated with the implementation of the study alternatives.  These generation impacts were next incorporated into several different power system modeling studies to estimate their effects on the power system from both the approaches of power production costing and power market pricing.  Finally, the computed production costs and market prices were each combined with additional costs estimated for transmission system impacts to give the net system economic effects from both viewpoints.

A wide range of important study assumptions and uncertainties were examined.  Sensitivity tests were performed on some of the major study assumptions to assure that the analysis results were reasonable.  Additionally, one of the power system models was used to identify the changes in air pollutant emissions from power production.

It must be noted that the assumptions and detailed parameters of the three power system models used are not completely consistent due to their proprietary nature and the variance in which the power system is professionally viewed.  To the extent possible, consistency of the model input data and model simulation criteria was attempted to be maintained.  As such, the outputs of the different models should not be considered apples and oranges, but rather different varieties of the same fruit.

## 5.1. Hydropower Project Characteristics

The hydropower project of main interest in this study was John Day Dam. Since the analysis also considered the effects of removing the four Lower Snake River dams (Ice Harbor, Lower Monumental, Little Goose, and Lower Granite ), those four dams were also of interest. Moreover, it must be noted that almost all of the hydropower projects in the Columbia-Snake river system would be affected in some way by each of the study alternatives. Table 1 shown below gives some of the hydropower characteristics of John Day Dam and the four Lower Snake River projects. The upper three Lower Snake River projects feature essentially identical hydropower production facilities while the Ice Harbor project provides slightly less capacity. Overload capacities shown represent the maximum output that can be achieved by the various powerhouses. The average annual energy generated is presented in two different units: the average megawatt (aMW) which is the amount of annual generation represented by an average capacity operating over one year, and the annual megawatt-hour (MWh) which is the total generation over one year. This energy generation data was obtained from the system hydro-regulation modeling results and represents the average 60-year Without Project Condition (baseline condition with John Day Dam operating at existing conditions; not to be confused with any condition with John Day Dam drawn down).

**Table 1.**
**Hydropower Plant Characteristics**

| | Ice Harbor | Lower Monumental | Little Goose | Lower Granite | Lower Snake River Total | John Day |
|---|---|---|---|---|---|---|
| **Number of Units** | 6 | 6 | 6 | 6 | 24 | 16 |
| **Nameplate Capacity Per Unit (MW)** | 3@90,<br>3@111 | 6@135 | 6@135 | 6@135 | ----- | 16@135 |
| **Total Nameplate Capacity (MW)** | 603 | 810 | 810 | 810 | 3,033 | 2,160 |
| **Overload Capacity (MW)** | 693 | 931 | 931 | 931 | 3,486 | 2,484 |
| **Unit In-Service Dates** | 1 1961<br>2 1962<br>3 1975 | 2 1969<br>1 1970<br>3 1979 | 3 1970<br>3 1978 | 3 1975<br>3 1978 | | 16<br>(from 1968 to 1971) |
| **Average Annual Energy Generation (aMW), Without Project Condition** | 219 | 335 | 317 | 329 | 1,200 | 1,146 |
| **Average Annual Energy Generation (1,000 MWh), Without Project Condition** | 1,918 | 2,935 | 2,777 | 2,882 | 10,512 | 10,039 |
| **Plant Factor, Without Project Condition** | 32% | 36% | 34% | 35% | 34% | 46% |

Figure 2 (shown below) presents estimates of John Day Dam power generation by month based on system hydro-regulation modeling results for the Without Project Condition and three different streamflow cases: 1) an average water year (1929-1988 average), 2) a low water year (1944-1945), and 3) a high water year (1955-1956). As can be seen, the amount of generation from this powerplant can change significantly between seasons and different streamflow conditions.

***FIGURE 2.  JOHN DAY MONTHLY GENERATION FOR WITHOUT PROJECT CONDITION***

1945=Low Water Year, 1956=High Water Year, AVG=60-Year Average

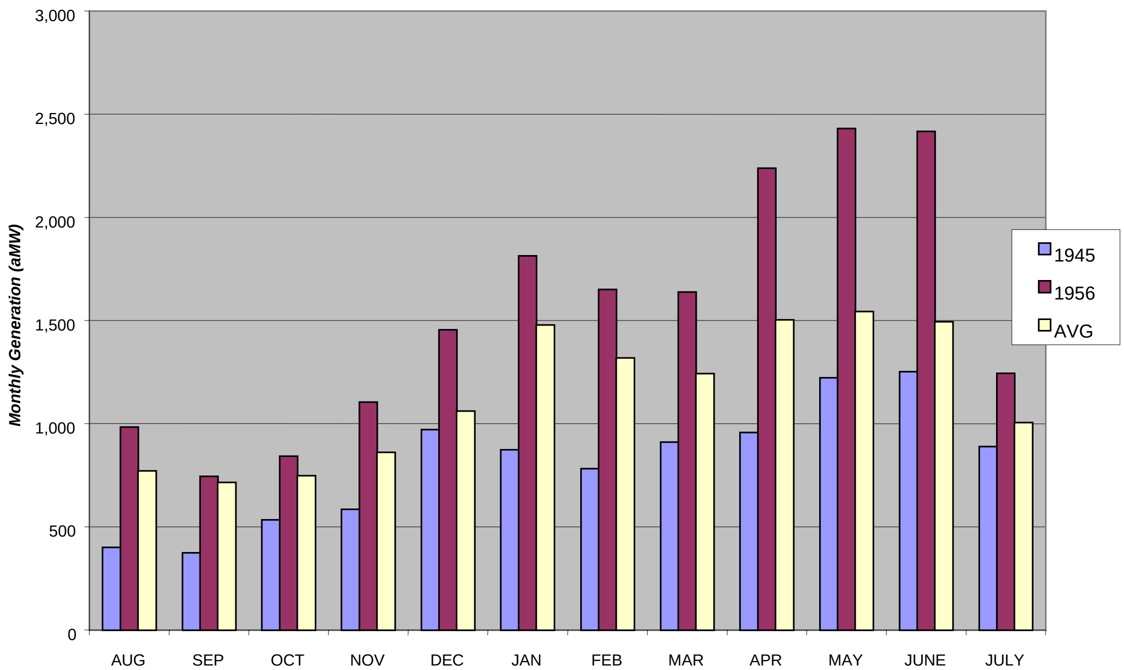
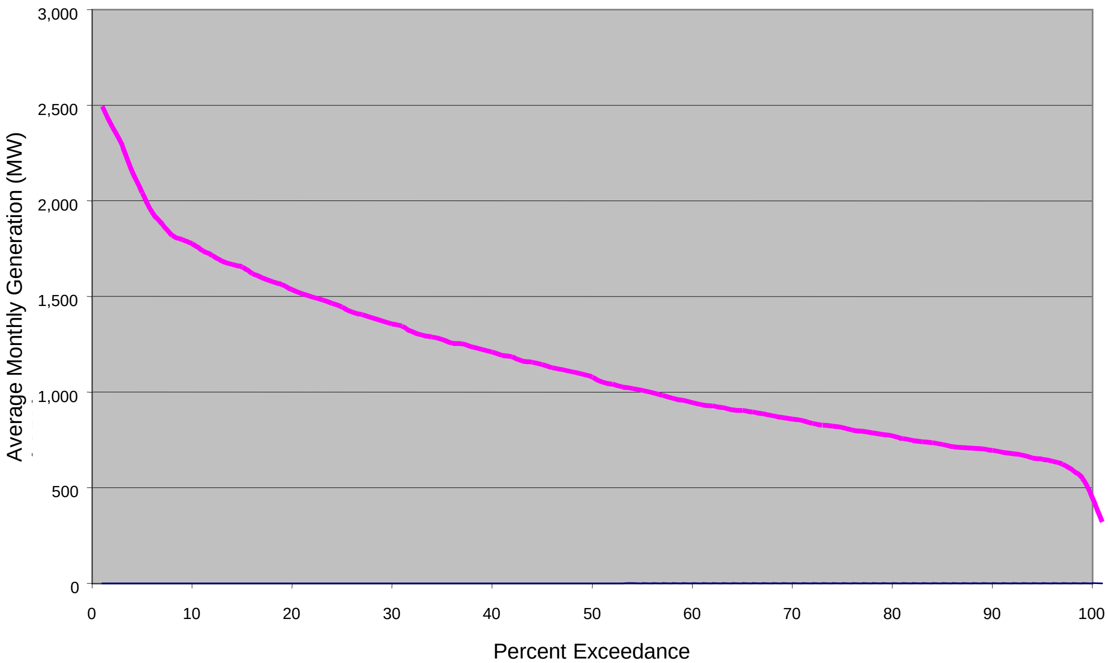



Figure 3 shown below presents the John Day Dam monthly generation-duration curve for the Without Project Condition as simulated by the hydro-regulation model based on the 60-year (1929-1988) historical streamflow record.  This figure shows the generation level equaled or exceeded by any percentage of time of the 60-year period.  For example, the monthly generation equals or exceeds 1,000 MW about 54 percent of the time, equals or exceeds 1,500 MW about 20 percent of the time, and equals or exceeds 2,000 MW about five percent of the time in the 60 years.

***FIGURE 3. JOHN DAY MONTHLY GENERATION-DURATION CURVE***




In general, hydroelectric projects contribute greatly to system reliability through the Automatic Generation Control (AGC) system that adjusts the system generation, second by second, to match changes in power demand. The power plants also fulfill a substantial part of the WSCC capacity reserve requirements and provide backup generation in the event of an unexpected outage of another generating powerplant. In addition, they provide extra energy during extreme and/or prolonged weather periods (if enough water from storage is available) and help maintain transmission stability during system disturbances. For all of these reasons, the power operations of John Day Dam play an important role in maintaining the flexibility, reliability, and transfer capability of the PNW generation and transmission systems which ultimately saves the region money. The hourly power generation level of John Day Dam is primarily determined by the amount of Columbia River water passed by McNary Dam (the next upstream dam) and the region's power demand (referred to as "load").

The impacts to the PNW transmission system from any changes in the power operations of John Day Dam are very complicated and difficult to analyze. These impacts may include greater electrical line losses from power having to be transmitted over greater distances and greater voltage instability from generation capacity loss. The most obvious specific impact would be to the California-Oregon Intertie (COI), the principal transmission link between the PNW and the Pacific Southwest (PSW). Due to John Day Dam's proximity to the COI, any substantial change in, or the permanent loss of power generating capability at John Day Dam would affect the region's ability to import and export power through the COI by reducing the COI's transfer limits. Even though sufficient power generation may be available in the West to make up for any loss at John Day Dam in the near term, actions beyond reinforcing the COI would have to be taken in order to maintain the same level of transmission reliability to

Pacific Northwest electricity consumers.[1] These actions include upgrading the transfer capability of several existing PNW transmission links as well as possibly building some new ones.

## 5.2. Power System Characteristics

Table 2 below presents the extent that each type of power-generating resource is used in the PNW. As shown in the table, hydropower resources make up about 67 percent of the Pacific Northwest's total generating capacity, followed by coal-based generation resources. Next in terms of capacity available to meet regional demand are the power imports from regions outside of the PNW. The firm energy amounts shown in this table reflect the average annual capacity demand that can be supported in the extreme low water year of 1936-1937 as computed by hydro-regulation modeling. This water year has been defined as the critical year to be used for calculating firm energy for most regional power planning studies. A distinction is often made between firm (also referred to as "primary") energy and non-firm (also referred to as "secondary") energy in power markets because the firm energy can be relied on in most extreme low streamflow years.

**Table 2.**
**Pacific Northwest Electric Generating Resources 1997[1]**

| Resource Type | Sustained Peak Capacity (MW)[2] | % of Total Capacity | Firm Energy[2] (aMW) | % of Total Firm Energy |
|---|---|---|---|---|
| **Hydro** | 25,887 | 67 | 12,187 | 57 |
| **Coal** | 4,521 | 12 | 4,061 | 19 |
| **Nuclear** | 1,162 | 3 | 841 | 4 |
| **Imports** | 2,996 | 8 | 1,669 | 8 |
| **Combustion Turbines** | 1,665 | 4 | 753 | 4 |
| **Non-utility Generation** | 1,166 | 3 | 1,051 | 5 |
| **Cogeneration** | 775 | 2 | 675 | 3 |
| **Other** | 264 | 1 | 171 | 1 |
| **Total** | 38,436 | 100% | 21,408 | 100% |

[1]Source: BPA's *1997 FAST FACTS*

[2]For more information see BPA's *Pacific Northwest Loads & Resources Study*

Table 3 shown below provides the energy generation and generating capacity information for the entire WSCC, based on historical 1997 data. As shown, the most prominent source of energy and capacity in the WSCC is also hydropower, though to a significantly less percentage extent than in the PNW—coal and natural-gas powered thermal plants provide a much larger share of the energy and capacity in the WSCC than in the PNW.

[1] Document 98-3, Pacific Northwest Power Planning Council. John Fazio, Senior System Analyst. February 25, 1998, Memorandum To Council Members, "Transmission System Impacts Of Drawing Down John Day Dam"

| Table 3. Western Systems Coordinating Council Electric Generating Resources, 1997 | | | | |
|---|---|---|---|---|
| **Resource Type** | **Capacity (MW)** | **% of Total Capacity** | **Energy (aMW)** | **% of Total Energy** |
| **Hydro – Conventional** | 61,043 | 39 | 33,367 | 39 |
| **Hydro – Pump Storage** | 4,316 | 3 | 533 | 1 |
| **Steam – Coal** | 36,325 | 23 | 28,378 | 33 |
| **Steam – Oil** | 746 | 0 | 239 | 0 |
| **Steam – Gas** | 23,241 | 15 | 5,018 | 6 |
| **Nuclear** | 9,258 | 6 | 7,472 | 9 |
| **Combustion Turbine** | 5,846 | 4 | 206 | 0 |
| **Combined Cycle** | 3,777 | 2 | 779 | 1 |
| **Geothermal** | 3,060 | 2 | 2,270 | 3 |
| **Internal Combustion** | 293 | 0 | 0 | 0 |
| **Cogeneration** | 8,119 | 5 | 5,954 | 7 |
| **Other, (Wind, Solar, etc.)** | 1,891 | 1 | 1,317 | 2 |
| **Pump-Storage Pumping** | | | (445) | -1 |
| **Total** | **157,915** | **100%** | **85,088** | **100%** |
| Source: 1998 WSCC Information Summary | | | | |

## 5.3. Alternatives Investigated in the Power System Analysis

The power system analysis examined a much wider range of alternatives than those investigated in the other portions of this Phase I Report. Since hydropower economic effects were expected to be a large component of the overall economic effects, the study team decided to expand the scope of the power system analysis to address the range of hydropower system operating scenarios that are currently being discussed in regional forums. The incremental time and cost of studying these additional scenarios was minimal because the study process had been established in the Lower Snake River Study. By performing the additional analyses, the study team wanted to ascertain whether breaching the Lower Snake River projects and changing the fisheries flow augmentation operations of other projects in the hydropower system would compound the economic effects associated with the drawdown of John Day Dam. The characteristics of the various scenarios investigated in this power system analysis are shown in Table 4. The first column of this table gives the formal alternative name that is used throughout this Phase I study; the second column gives the scenario name for all of the alternatives performed in the power system analysis. To avoid confusion, reference to the formal alternatives of the Report will have the corresponding scenario name enclosed in brackets while the additional alternatives will be referenced directly by their scenario name. For more detail on each of these scenarios and a description of the model, see the Hydro-regulation Appendix.

The Without Project Condition Alternative is represented by the power analysis scenario entitled JD1. This alternative represents the operation of the system most likely to occur in the future without any modifications to John Day Dam. It incorporates the operational objectives from the NMFS 1998 Steelhead Supplemental Biological Opinion (1998 BiOp) and the revised objectives from USACE 1999 Bull Trout and Sturgeon Biological Assessment.

Alternative 1 is the alternative with the John Day project operating pool drawn down to the spillway crest level with no flood control capability, and the Lower Snake River projects operating at Minimum Operating Pool (MOP). Alternative 2 is the same as Alternative 1 except that there is on-site flood control capability. The exclusion or inclusion of flood control capability at John Day Dam did not influence the amount of monthly power generation as defined in the hydro-regulation model. It was assumed that the John Day project would be operated for flood control by raising the operating pool and storing water until the risk of flooding downstream had subsided. Since this would only last for a few days to a week, it was not considered to affect the power generation at John Day Dam. Because Alternatives 1 and 2 are identical from a power generation point of view, they are both represented by the power analysis scenario entitled JD2.

Alternative 3 differs from Alternative 1 only in that it has John Day Dam operating at the natural river level instead of at the spillway crest level. Alternative 4 is to Alternative 3 as Alternative 2 is to Alternative 1—that is, only having a difference in on-site flood control capability. Consequently, because Alternatives 3 and 4 are also identical from a power generation point of view, they are both represented by the power analysis scenario entitled JD5.

**Table 4.**
**Study Alternatives and Power Analysis Scenarios**

| Study | Power | John Day Level | | | Snake R. Dams | | U.Snake Flow Augmentation | 1995 BiOp Flow Augmenation | |
|---|---|---|---|---|---|---|---|---|---|
| **Alternative** | **Scenario** | **Existing** | **Spillway** | **Nat River** | **Nat Riv** | **MOP** | **kaf** | **Columbia** | **Snake** |
| | | | | | | | | | |
| **Without Project Condition** | JD 1 | **X** | | | | **X** | **427** | **X** | **X** |
| | **John Day at Spillway** | | | | | | | | |
| **Alternative 1&2** | JD 2 | | **X** | | | **X** | **427** | **X** | **X** |
| | JD 3 | | **X** | | **X** | | **427** | **X** | **X** |
| | JD 4 | | **X** | | **X** | | **0** | **X** | |
| | **John Day at Natural River** | | | | | | | | |
| **Alternative 3&4** | JD 5 | | | **X** | | **X** | **427** | **X** | **X** |
| | JD 6 | | | **X** | **X** | | **427** | **X** | **X** |
| | JD 7 | | | **X** | **X** | | **0** | | |
| | | | | | | | | | |

The other power analysis scenarios represented variations in the operation of the four Lower Snake River projects (either at MOP or at natural river levels) as well as changes in fisheries flow augmentation from the Upper Snake River storage, the Lower Snake River storage, and/or the Columbia River storage.

## 5.4. Hydro-Regulation Modeling

The first step in determining the hydropower impacts was to identify the amount of system hydropower generation that can be expected with each power analysis scenario. This was done by utilizing a system hydro-regulation model which chronologically simulates the operation of hydropower system with historical water conditions spanning 60 years. The hydro-regulation model used is entitled the Hydro System Seasonal Regulation Program (HYSSR), developed and maintained by the Corps of Engineers' Northwestern Division. The major output of the model is a month-by-month, year-by-year, hydropower generation summary for each plant in the Columbia River Basin.

Table 5 shown below summarizes the average 60-year monthly system generation for each of the power analysis scenarios including the Without Project Condition Alternative (JD1). The table also shows the differences in system generation between JD1 the other scenarios for comparison purposes. These differences in computed system hydropower generation are used later in this analysis to define the economic effects of all the power analysis scenarios.

**Table 5. HYSSR Results By Study Alternative and Power Analysis Scenario**
**Average System Generation Over 60 Water Years (aMW)**

| Study Alternative | Power Scenario | AUG1 | AUG2 | SEP | OCT | NOV | DEC | JAN | FEB | MAR | APR1 | APR2 | MAY | JUN | JUL | AVG |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | |
| Without Project Condition | JD1 | 13,374 | 10,610 | 9,186 | 9,347 | 11,111 | 13,117 | 16,858 | 15,015 | 13,597 | 14,954 | 17,185 | 18,202 | 18,361 | 14,308 | 13,930 |
| Alternatives 1&2 | JD2 | 12,868 | 10,278 | 8,891 | 9,054 | 10,772 | 12,607 | 16,371 | 14,434 | 12,945 | 13,988 | 16,395 | 17,308 | 17,622 | 13,786 | 13,379 |
| | JD3 | 11,754 | 9,604 | 8,396 | 8,372 | 10,203 | 11,669 | 15,182 | 13,297 | 11,459 | 12,040 | 14,245 | 15,239 | 15,754 | 12,617 | 12,167 |
| | JD4 | 11,742 | 9,475 | 8,464 | 8,428 | 10,303 | 11,641 | 15,329 | 13,439 | 11,482 | 11,742 | 14,334 | 15,284 | 15,777 | 12,481 | 12,189 |
| Alternatives 3&4 | JD5 | 12,395 | 9,984 | 8,663 | 8,696 | 10,411 | 12,096 | 15,683 | 13,758 | 12,305 | 13,112 | 15,568 | 16,602 | 17,022 | 13,360 | 12,843 |
| | JD6 | 11,249 | 9,300 | 8,210 | 8,155 | 9,804 | 11,186 | 14,336 | 12,554 | 10,753 | 11,174 | 13,420 | 14,583 | 15,101 | 12,059 | 11,609 |
| | JD7 | 9,945 | 8,495 | 8,241 | 8,964 | 10,518 | 12,150 | 15,555 | 13,134 | 11,223 | 11,892 | 12,679 | 14,054 | 13,731 | 11,406 | 11,706 |

**CHANGE IN SYSTEM GENERATION FROM WITHOUT PROJECT CONDITION (aMW) 2/**

| Study Alternatives | Scenarios | AUG1 | AUG2 | SEP | OCT | NOV | DEC | JAN | FEB | MAR | APR1 | APR2 | MAY | JUN | JUL | AVG |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | |
| Alternatives 1&2 | JD2 | -506 | -332 | -295 | -293 | -339 | -510 | -487 | -581 | -652 | -966 | -790 | -894 | -739 | -522 | -551 |
| | JD3 | -1,620 | -1,006 | -790 | -975 | -908 | -1,448 | -1,676 | -1,718 | -2,138 | -2,914 | -2,940 | -2,963 | -2,607 | -1,691 | -1,763 |
| | JD4 | -1,632 | -1,135 | -722 | -919 | -808 | -1,476 | -1,529 | -1,576 | -2,115 | -3,212 | -2,851 | -2,918 | -2,584 | -1,827 | -1,741 |
| Alternatives 3&4 | JD5 | -979 | -626 | -523 | -651 | -700 | -1,021 | -1,175 | -1,257 | -1,292 | -1,842 | -1,617 | -1,600 | -1,339 | -948 | -1,087 |
| | JD6 | -2,125 | -1,310 | -976 | -1,192 | -1,307 | -1,931 | -2,522 | -2,461 | -2,844 | -3,780 | -3,765 | -3,619 | -3,260 | -2,249 | -2,321 |
| | JD7 | -3,429 | -2,115 | -945 | -383 | -593 | -967 | -1,303 | -1,881 | -2,374 | -3,062 | -4,506 | -4,148 | -4,630 | -2,902 | -2,224 |

1/ The months of August and April are split into two periods to reflect the significant differences in flow from the first half to second half of these months.

2/ A negative number means there is a loss in average generation from the without project condition (scenario JD1)

## 5.5. Power System Models

The study team used several models in the analysis. The specifics of each model are provided in the Lower Snake River Juvenile Salmon Migration Feasibility Study report, *Technical Report on Hydropower Costs and Benefits, 31 March 1999.* In general, the results from the hydro-regulation models were used as input to the economic models. Each economic model provided somewhat different outputs, so additional analysis was added to model results to define the net economic effects.

Because of the inter-related, market-driven nature of the electric industry, it was decided that the evaluation of changes in hydropower production in the PNW must be evaluated system-wide. The Snake River study used two separate system production cost models, one by USACE and one by BPA, to evaluate the net economic effects of changing power generation at the four Lower Snake Dams and John Day. A third approach developed by the Northwest Power Planning Council (NPPC) was also used in the Snake River study and in this analysis. USACE' model was used primarily to confirm the results from the other models in the Lower Snake analysis. For this study, the system production costs for all alternatives were modeled with the BPA model and USACE model was used to evaluate the natural river level alternatives and to identify air emission estimates from electricity producing power plants. USACE model was also used to estimate the market clearing prices as a comparison to those produced in the NPPC analysis.

These multiple approaches were undertaken to look at the impacts from different analytical viewpoints to assure that the economic effects are adequately bracketed in the final estimates. The study progressed by examining model results for each alternative with the different system approaches. To the extent possible, the basic input assumptions were standardized among the models, and these assumptions are discussed below. Upon comparing results, the study team built a consensus on the selected analytical approach.

The evaluation of the net economic effects on hydropower was based on two basic approaches: a market price analysis and a system production cost analysis. The AURORA and PROSYM models served as the basic tool for the market price analysis. The BPA model and Corps' PROSYM model were used for the system production costs analysis. It is important to note that the market price and system production cost approaches are intended to measure the same net economic effects, and hence are directly comparable.

Although many similarities do exist in the power system models used in the analysis, there are differences. The models are designed to identify how the different power generating resources will be operated to meet projected power loads (demand). They do vary in scope from hourly models (AURORA) to a monthly model that stratifies hours in the month into different blocks of peak and non-peak hours. The geographic regions covered by each model are different. The treatment of constructing new power resources, maintaining system reliability and retiring power plants varies among the models. The primary outputs of each model are different. The AURORA and PROSYM models identify the marginal cost in each period and this is assumed to be the market-clearing price. The BPA and Corps models also identify production costs. The BPA model provides the fixed costs of new resources to arrive at the total system production costs. USACE' PROSYM model also provides the fixed and variable costs to derive total system production costs. Because these models were developed independently and are modeling a complex system, it is not surprising there are differences. However, it is reassuring that the models predict relatively similar results given the same general input assumptions

### 5.5.1. System Production Cost Model

System production cost analysis was one approach use to define net economic effects. The economic effects were identified by comparing system production costs with the level of hydropower production from the different alternatives being investigated. Changes in hydropower generation result in different levels of operation of more costly thermal generating power plants. Hence, the economic values of different increments of hydropower energy were defined by the displacement of thermal resource generation.

For this analysis the total system production costs are defined as the sum of the variable operating costs (production costs) and the fixed costs (annualized capital costs) of new resources added to meet loads. The total system is defined by different geographic regions in each model. However the basic definition is,

Total System Production Costs = Variable Costs (Production) + Fixed Costs (New Capacity)

The BPA model estimated the costs of meeting energy demand (loads) with available hydropower energy and thermal resources. The model identifies the most cost-effective way to meet loads given all system constraints. The model estimates which resources will be operated to meet loads; the variable costs of these resources are summed to define variable production costs. Loads may also be met through the purchase of energy from the PNW, PSW, or other regions. The purchase price reflects the variable generation costs and the transmission costs of the resource used to provide the energy. Production costs in the PNW and PSW will vary depending on how much Columbia River hydropower is generated. The output of the hydro-regulation model (HYSSR) served as the major input to the system energy production cost model.

Table 6 shown below provides a description of the major concepts of the BPA model. The model categorizes West Coast thermal resources into several production cost blocks based on the average efficiencies of the plants. The more inefficient plants tend to be, the older plants that are operated last in the dispatch order. The BPA model compares the PNW and PSW loads to the monthly hydropower and thermal generation for each simulation year. As hydropower generation varies, the thermal generation amounts and costs change. The model identifies the marginal costs of the resources which hydropower will displace. The load is broken into three distinct periods of each week or month as shown below. This stratification accounts for the significant variations in prices and resources used to meet loads in these different periods of the week.

- Super peak (hours 7 a.m. to 10 a.m. and 5 p.m. to 8 p.m. each weekday)
- Peak (hours 6 a.m. to 10 p.m. Monday through Saturday, not including the super peak hours)
- Non-peak hours (the remainder of the week)

| **Table 6.<br>BPA Regional Power Model Characteristics** | |
|---|---|
| **Model Philosophy and Use** | • Underlying philosophy is that the future value of electricity in the PNW will be determined by the cost of operating the next available West Coast resource—either operation of existing resources or construction and operation of new resources.<br>• Model has a PNW and a PSW region. Canada and the Inland SW are not modeled.<br>• Model attempts to meet West Coast loads with West Coast resources. Each region's resources are used to meet its own loads. If the PNW has surplus resources, they are available for sale to the PSW. If the PNW is deficit, PSW resources are available for purchase (both transactions subject to intertie limits).<br>• Model calculates results on a monthly basis, but is also capable of dividing the month into super peak, peak and non-peak hours. Currently, super peak hours consist of 30 hours per week, peak hours consist of 66 hours per week, and non-peak hours consist of 72 hours per week.<br>• Results consist of the total cost for operating the West Coast regional electric system. Total costs include variable costs of all resources and the fixed costs for any new resources. Other outputs consist of the marginal cost for meeting an increment of PNW load, PNW load/resource balances, operation of specific resource blocks, and many other outputs. |
| **Existing System** | • The PNW region consists of information on PNW loads and resources. PNW resources are divided into six groups: non-displaceable (nuclear, renewables, etc.); low cost coal (mostly east-side coal plants); high cost coal, existing single cycle combustion turbines (CTs), existing combined cycle combustion turbines (CCs) and imports.<br>• The PSW region consists of information on PSW loads and resources. PSW resources are grouped into two categories: displaceable and non-displaceable. Further, displaceable PSW resources are defined by their heat rates. A supply curve of PSW resources by heat rate is developed in the model.<br>• Data for both regions consist of existing loads, existing resources, variable cost of operating existing displaceable resources, current and future gas prices.<br>• Data for the PNW includes monthly hydro generation based on 50 historical water years.<br>• Data for both regions includes the cost for failing to meet native loads (cost of unserved load). |
| **New Resources** | • The model has a limited optimization routine based on the following philosophy: new resources will be built when they are less expensive to build and operate than the combination of the cost of operating existing resources and curtailing load, when no other resources are available. Existing resources consist of both supply and demand side resources. The only future resource choice is new combined cycle combustion turbines (CCs). |
| **Operations** | • Model operates from a PNW perspective. Model checks whether or not PNW is surplus or deficit given operation of all existing and new resources. If surplus, dispatch logic (hardwired in model) is as follows:<br>• Displace all PNW existing CT resources.<br>• Displace all PNW high cost coal resources.<br>• Sell to PSW (given intertie and market limits).<br>• Displace all PNW existing CC resources.<br>• Displace all PNW new CC resources.<br>• Displace all PNW low cost coal resources.<br>• Displace imports.<br>• If deficit, model buys from the PSW (given intertie limits and PSW resource availability). If no PSW resources available, model purchases available demand side resources, and then curtails PNW load. |
| **Uncertainties** | • Model handles uncertainty in PNW hydro by modeling 50 years of historic hydro information.<br>• Model has three different load forecasts for the PNW and PSW—low, medium and high.<br>• Model has three different gas price forecasts for the PNW and PSW—low, medium and high. |

USACE used an existing proprietary hourly system production model entitled PROSYM, which has been used extensively for hydropower evaluations by USACE throughout the United States. PROSYM was developed and is maintained by Henwood Energy Services Incorporated (HESI) of Sacramento, California. The Corps of Engineers (CENWD-NP-ET-WP) used the model under a contract with Henwood. USACE has utilized this model and its TVA-developed predecessor POWRSYM since 1983. Table 7 provides a description of the major concepts of the model. The PROSYM model interfaces with an extensive database system developed by Henwood called Electric Market Simulation System (EMSS), which includes operating characteristics of all WSCC power plants, current fuel prices, plant efficiencies, EPA emissions data and inter-regional marketing conditions. The PROSYM model dispatches thermal and hydropower resources on an hourly basis to meet energy demand. It estimates the most cost effective and efficient operation to meet loads by dispatching hydropower resources in the peak demand periods first. Then thermal resources are dispatched, typically in order of increasing energy cost, to meet the residual demand. PROSYM determines the marginal cost for an hour as being the cost of the last added thermal resource utilized to meet the demand for that period. Loads are analyzed for peak and non-peak periods. The peak period was considered to be from 7am to 10pm weekdays and Saturday and the non-peak period was all other times. A total of eighteen transmission areas or regional load centers was modeled to reflect generating resources in the entire WSCC. The transmission areas are inter-linked by transmission lines to allow for the exchange of energy between areas given system constraints. System production costs, which include variable operating costs and fixed cost for new generation sources, are computed for each transmission area and summed for the WSCC total production cost.

Hydropower resources are based on weekly energy amounts generated by the HYSSR hydropower regulation model from the projects in the study region. The model dispatches the hydropower to follow loads to capture the daily peaking capability of hydropower. PROSYM was used to analyze in great detail Alternatives JD1, the existing case and JD5, the natural river alternative based on average water for the 60-year historical period 1928 to 1988. The model also includes a pollution emissions subroutine that quantified three pollutants, sulfur oxides, nitrogen oxides and carbon dioxide. Emissions data was derived from the Environmental Protection Agency's Continuous Emission Monitoring System data for the period reported from July 1996 to June 1997. The data was averaged to determine average emissions rates for the three types of emissions.

| **Table 7. Corps of Engineers' PROSYM Model** | |
|---|---|
| **Model Philosophy and Use** | • Simulates a power system operation on a chronological hourly basis.<br>• Simulates a year hour-by-hour, in one-week increments.<br>• Used to define power system operating costs (variable costs of operating resources) to meet loads.<br>• Operating costs for each plant includes fuel costs, variable operation and maintenance costs, fixed cost and startup costs.<br>• Meets hourly loads in the most economic manner possible given a specified set of generating resources.<br>• Recognizes operating constraints imposed on individual units |
| **Existing System Simulation** | • Uses external data (like HYSSR output) to define hydropower week-by-week generation.<br>• Data utilized for thermal plants include: unit capacity, fuel type, number of units per plant, ramp rate, fuel cost, minimum and maximum unit output, minimum down time, variable heat rate, forced outage rate, minimum up time, start-up costs, maintenance schedule, on-line date, retirement date, categorization by type such as base load, intermediate, or peaking.<br>• Dispatched in order of increasing energy costs, unless fuel supply contracts or other factors require a specific dispatch.<br>• After units are dispatched, a probability distribution is used to develop forced outages, and contingent resources are then dispatched.<br>• Hydropower inputs required: (Can define numerous types of hydropower units)<br>- Required minimum continuous output<br>- Normal maximum output<br>- Energy output for each week<br>- Peaking output<br>- Pump storage characteristics<br>• Multi-area capability allows for bi-directional line limits, transmission losses, and wheeling charges. Unit commitment and dispatch is fully “transmission-network aware”.<br>• Can incorporate area-level operating reserve requirements.<br>• Calculates the marginal cost data for each transmission area. |
| **New Resources** | • User specifies new resources to meet load if existing resources are inadequate.<br>• Planned resources can be modeled to come online at specified dates in the future. |
| **Operation** | • Uses extensive Regional Databases developed from unrestricted sources such as FERC filings, NERC reliability councils, state regulatory and planning commissions, etc.<br>• Output is production costs by resource to meet weekly load.<br>• Output available by regions, by plants, and by plant types.<br>• Includes a pollution emission subroutine that estimates emissions with each scenario. |

## 5.5.2. Market Price Model

The conceptual basis for evaluating the benefits from energy produced by hydropower plants is society’s willingness to pay for the outputs, which sometimes can be obtained through market prices. With the movement towards a more competitive market, electricity in the California market and elsewhere is being priced at or near the marginal production cost of the last resource to provide the needed electricity. Therefore, this part of the power analysis looked at valuing the incremental changes of hydropower generation at the market price, which was based on the marginal cost of the last resource used to meet load in the specific time frame.

As more competitive electricity markets develop, prices will not be set to average costs as they have been in the past. Rather, the various services provided—operating reserves, voltage stabilization, etc.—will be available and priced separately. However, consumers will not have to purchase all of these services from separate suppliers. During most time periods in the power spot market, the generation price of electricity will be set by the operating costs of the most expensive generating unit needed to meet demand, or what is referred to in economics as the "marginal cost" of production. In general, a supplier will not be willing to sell power below the market price of the most expensive facility operating at a given time, because consumers will be willing to pay the higher price. Similarly, consumers will be unwilling to pay more than the cost of the most expensive operating available generator, since other suppliers will be offering lower prices. With prices set to marginal costs, the market will clear: all suppliers willing to provide power and all consumers willing to purchase power at the market price will be doing so.

#### 5.5.2.1. The AURORA Model

Market prices were obtained from the NPPC study entitled, *Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues, 5 June 1998.* The market prices used in this study were developed with a model called AURORA, developed by a private firm, EPIS, Inc. The general elements of the AURORA model are provided here.

One of the principle functions of AURORA is to estimate the hourly market-clearing price at various locations within the WSCC. AURORA estimates prices by using hourly demands and individual resource operating characteristics in a transmission-constrained chronological dispatch algorithm. The operation of resources within the WSCC is modeled to determine which resources are on the margin for each area in any given hour.

In AURORA, the WSCC is broken into 12 geographic areas largely defined by states, with the exception of California, which is split into a northern and southern area, and Oregon and Washington, which are combined into one area. Long-term average demand and hourly demand shapes for these regions are input. These demand regions are connected by transmission links with specified transfer capabilities, losses, and wheeling costs.

Existing generating units, approximately 2,000 in the WSCC, are defined and modeled individually with specifications of a number of cost components, physical characteristics, and operating constraints. Hydro generation for each area, with instantaneous maximums, off peak minimums, and sustained peaking constraints are also input. Demand side resources and price induced curtailment functions are defined, allowing the model to balance use of generation against customer demand reduction alternatives.

AURORA uses this information to build a least-cost dispatch for the WSCC. Units are dispatched according to variable cost, subject to non-cycling and minimum run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs, and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area. All operating units in an area receive the hourly market clearing price for the power they generate.

The hourly market clearing prices are developed on an area-specific basis. The analysis for this report uses the Oregon/Washington area price to value PNW generation. This price can be interpreted as the average busbar price as seen by generation in the Oregon/Washington area. Charges for delivery within the Oregon/Washington area are not included in the price. AURORA also has the capability to simulate the addition of new generation resources and the economic retirement of existing units. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources will only be built when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable, i.e. the ability of investors to recover fixed and variable costs with an acceptable return on investment. AURORA uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules. This effectively results in construction and retirement decisions being based on "perfect knowledge" of future prices.

Existing units that can't generate enough revenue to cover their variable and fixed operating costs over time are identified and become candidates for economic retirement. To reflect the timing of transition to competition across all areas of the WSCC, the rate at which existing units can be retired for economic reasons is constrained in these studies.

#### 5.5.2.2. The PROSYM Model

The PROSYM model was also used to determine market prices. It determines market clearing prices based upon the marginal cost of the last resource. It is similar to the AURORA model in that it uses information on loads and resources that are defined for 18 different geographic areas to dispatch thermal and hydropower resources on an hourly basis to meet energy demand. One of the primary differences between the PROSYM and AURORA models is that the PROSYM model does not add or retire new resources based upon the profitability or economic feasibility of the plants. PROSYM conservatively estimates resource retirements to be only those that are publicly announced in the WSCC *Coordinated Bulk Power Supply* report. It utilizes existing or new resources to meet hourly power demands based upon a set of reliability and reserve criteria established by the user.

### 5.5.3. Model Inputs and Assumptions

This section describes the major inputs used in the BPA PROSYM and AURORA models. Most of these key model assumptions for the BPA and AURORA models were taken from the NPPC report, *Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues, 5 June 1998*. In the Lower Snake River Study, a range of projections (low, medium, and high) was made for each key variable to account for the uncertainty associated with predicting future conditions. The PROSYM model used somewhat different assumptions that were developed in consultation with Henwood Energy Services, the developer of the PROSYM model, and a power system modeling consultant with extensive experience in this field. Most projections used in this analysis assumed medium future projections.

**Elasticity of Demand.** One major simplifying assumption made in this analysis is that consumers of electricity have a zero price elasticity of electricity demand—this means that consumers will use the same amount of electricity regardless of its price. This assumption contradicts the probable reduction in demand for electricity at the wholesale and retail levels that will occur if electricity prices increase with the implementation of the John Day drawdown alternatives. The extent to which this assumption may effect the estimate of economic impacts is unknown, but it most likely results in overstating the economic effects.

Other studies that accounted for the price elasticity of electricity demand showed the economic effects to be around ten percent less than studies not accounting for elasticity. It was considered beyond the scope of this study to estimate elasticity for each consumer type.

**System Loads.** The average annual system loads for each of the 12 AURORA demand regions are shown in Table 8 below for the initial analysis year of 1997. These loads were used in both the BPA and AURORA models.

**Table 8.**
**AURORA Model**
**1997 Electric Loads by Demand Region**

| Region | Load (aMW) |
|---|---|
| OR/WA | 16779 |
| North CA | 10730 |
| South CA | 16783 |
| Canada | 11842 |
| ID | 2644 |
| MT | 1554 |
| WY | 1455 |
| CO | 4681 |
| NM | 2106 |
| AZ | 6474 |
| UT | 2481 |
| NV | 2817 |
| TOTAL | 80346 |

Source: NPPC's study, "*Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues, 5 June 1998*"

Power demand was assumed to grow at a 1.5 percent annual rate in all of the demand areas considering the future uncertainty in demand growth. Although this will certainly not be the case, demand forecasts were not researched because of rapidly changing and uncertain demographic trends. It was also felt that using the historical growth rates was not justified for the same reason.

For the PROSYM model load data was taken from Federal Energy Regulatory Commission (FERC) Form 714 as filed by the utilities in the WSCC. These data represent each utilities most recent recorded historical load and their most recent load forecast. Based on the load-forecast data, non-coincidental peak demand in southern California and the entire WSCC are expected to both grow at about two percent per year through the study period. Coincidental WSCC loads also are projected to grow by two percent per year, while California loads are forecast to rise by 1.8 percent per year.

To determine hourly fluctuations in demand over the course of a year, the PROSYM model utilized 1993 through 1997 historical load data filed with the FERC by utilities. This data was used to create an hourly load shape curve consistent with the load forecasts provided by utilities. These “synthetic” load shape curves were combined with utility forecast load growth rates to forecast regional electricity loads throughout the forecast period.

**Fuel Prices.** The major component of the production costs for any power system is the cost of the fuels expended to generate the electricity. Hence, the fuel prices assumed to occur over time are a critical element of the system production cost modeling and the market price analysis. This section describes the assumptions made for the fuel prices in the different regions of the WSCC.

**Natural Gas Prices.** Natural gas is a particularly important fuel in the WSCC. In California, gas-fired power plants are often on the margin and as a result, set electricity market clearing prices for a high percentage of hours in each year. The AURORA model is currently structured to develop its natural gas pricing assumptions based on two pricing points—the Henry Hub in Louisiana and the Permian Hub in Texas. Prices for the AURORA regions are based on a series of differentials from the prices at these trading hubs. The results of making the differential adjustments are shown in Table 9 below. This table shows the assumed natural gas prices on a $/million BTU ($/MMBtu) basis for 1997. A medium projection gas price escalation rate of 0.8 percent per year used by the NPPC was assumed to be applicable. These natural gas prices were used in both the BPA and AURORA models.

**Table 9.**
**AURORA 1997 Natural Gas Prices By Region ($/MMBtu)**

| Region | Sub-Region | Estimated Start Price |
|---|---|---|
| CA Border | | $1.90 |
| | Southern CA | $2.15 |
| AZ | | $2.10 |
| NM | | $1.95 |
| NV | | $2.00 |

Gas is delivered to market hubs and city gates based on their proximity to gas supply basins located throughout North America. For example, gas traded at the Malin border point in northern California originates, in general, from the Alberta supply basin. The PROSYM model developed its forecast of natural gas burner tip prices on the basis of market hub and transportation costs. The choice of market hub and city gate used was based on proximity to the power plant and observed gas corridor flows. From the market hub or pricing point, transportation costs to the burner tip consisting of interruptible LDC charges or intrastate and interstate tariffs if appropriate were added.

To forecast future burner tip gas prices, PROSYM employed a modified “Delphi” approach. Two expert sources were utilized to derive annual growth rates in burner tip prices delivered to electric generators. The *Annual Energy Outlook 1998 with Projections to 2020*, provided by the Energy Information Administration (EIA) and the Gas Research Institute’s (GRI) *Baseline Projection 1999* were used for this task. A regional weighted average price growth rate from each organization was used and applied to the market center and interruptible transportation component. The burner tip gas price within the WSCC was developed by combining the monthly market hub price with the transportation costs. Table 10 provides a forecast of annual burner tip gas prices for western delivery points.

| Table 10.<br>PROSYM Base Case Forecast<br>Electric Generator Burner Tip Gas Price<br>(1999 $/MMBtu) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Pacific Northwest** | **Northern Nevada** | **Pacific Gas & Electric** | **Southern California Edison** | **San Diego Gas & Electric** | **Arizona and New Mexico** | **Rocky Mtn Colorado** | **Southern Nevada** |
| **2000** | 2.29 | 2.53 | 2.60 | 2.89 | 2.92 | 2.50 | 2.21 | 2.55 |
| **2005** | 2.35 | 2.74 | 2.78 | 2.96 | 3.00 | 2.72 | 2.39 | 2.76 |
| **2010** | 2.45 | 2.86 | 2.90 | 3.08 | 3.11 | 2.82 | 2.50 | 2.88 |
| **2015** | 2.50 | 2.94 | 2.99 | 3.17 | 3.21 | 2.91 | 2.57 | 2.96 |
| **2020** | 2.59 | 3.13 | 3.17 | 3.32 | 3.36 | 3.05 | 2.73 | 3.15 |

Another forecast component is the seasonal variation in gas price. In general, gas prices are high during winter months due to greatly increased core heating demand. To determine the seasonal variation in gas prices, data at individual pricing points were utilized. The observed seasonal pattern was then applied to annual gas price forecasts to derive monthly price forecasts that were used in PROSYM market simulations. These seasonal factors represent typical or normalized variation in monthly spot gas prices within a region. Interruptible transportation tolls were assumed to remain constant throughout the year. Although Table 9 shows gas prices increasing in future years, the PROSYM simulations utilized non-escalated gas prices for USACE analysis per Corps guidelines.

***Oil Prices.*** In the AURORA and BPA models for the base year of 1997, it was decided to use the starting crude oil prices at $3.50/ MMBtu with a low projection real escalation rate of 0.5 percent per year. This escalation rate was also applied to all of the oil fuels. The 1997 starting values that were selected for crude oil and the other fuel oils are shown below in Table 11. These fuel oil prices were used in both the BPA and AURORA models.

| Table 11.<br>Fuel Oil 1997 Prices Used in Analysis | |
|---|---|
| **Fuel Oil Type** | **1997 Price ($/MMBtu)** |
| Crude Oil | $3.50 |
| #1 Fuel Oil | $5.00 |
| #2 Fuel Oil | $4.50 |
| #3 Fuel Oil | $4.25 |
| #4 Fuel Oil | $3.85 |
| #5 Fuel Oil | $3.50 |
| #6 Fuel Oil | $2.70 |

Oil prices used in the PROSYM model are shown in Table 12 below. A one-percent escalation rate was applied to each oil type from a base year of 1996.

| Table 12. PROSYM 1996 Fuel Oil Prices | | | |
|---|---|---|---|
| **Fuel Name** | **Fuel Price ($/MMBtu)** | **Fuel Base Year** | **Fuel Description** |
| Jet.Fuel | $5.51 | 1996 | Jet Fuel |
| Arizona/New Mexico #2 | $5.51 | 1996 | Oil #2 |
| California #2 | $5.51 | 1996 | Oil #2 |
| Pacific Northwest #2 | $5.51 | 1996 | Oil #2 |
| Rocky Mtn Region #2 | $5.51 | 1996 | Oil #2 |
| Arizona/New Mexico #6 | $3.05 | 1996 | Oil #6 |
| California #6 | $2.99 | 1996 | Oil #6 |
| Pacific Northwest #6 | $3.05 | 1996 | Oil #6 |
| Rocky Mtn Region #6 | $2.99 | 1996 | Oil #6 |

***Coal Prices.*** The other fuel, besides natural gas, that plays a significant role in the market price of electricity is coal. In the AURORA and BPA models it was assumed that coal prices would decline in real terms at 1.0 percent per year based on data given in the Energy Information Administration (EIA) publication, *Annual Energy Outlook, 1998*. Prices for coal are not given because coal is usually not traded on the open fuel markets and consequently does not have an industry-wide price. Rather, it is usually bought and sold on private long-term contracts between the transacting parties. Coal prices are thus different for most coal-fired generating powerplants but are disclosed through mandatory utility reporting to the FERC. Both BPA and AURORA models make use of this FERC coal price data.

Coal prices used in the PROSYM model are based on historical powerplant specific coal price data extracted from Form 423 filed by utilities to the FERC. Form 423 data include historical consumption as well as both spot and average prices (transportation and so-called fixed fees included). Given the competitive nature of fuel supply markets and the current pricing of coal relative to gas, PROSYM used a coal price forecast containing real price escalation of –0.9 percent through the forecast period. Spot coal prices were used to simulate the economic operation of coal plants. Spot prices are historically about 77 percent of average prices. In cases where data is unavailable, regional coal prices were used as a proxy.

***Generating Resources: Existing and Future.*** To meet load growth over time, it was necessary to project the type of resources that will be built in the future and to identify the conditions under which they will be built. Using the AURORA model it was found that the predominate type of powerplant that has been recently added in the WSCC has been natural gas-fired combined-cycle combustion turbine (CC) plants. CC powerplants are generally considered the most cost-effective new generating resource capable of operating over a wide range of potential plant factors. It was assumed in the BPA and AURORA models that all new thermal-based resources to be built through year 2020 would be CC powerplants.

A detailed analysis was performed by HESI for USACE to determine future thermal resources in the WSCC. Based on the HESI analysis of new generating technologies, gas-fired combined-cycle units (CC) and gas-fired combustion turbines (CT) were added as needed to meet the projected increase in customer demand over the forecast period. HESI's analysis assumed that generation resources will be added over the forecast period in the ratio of 3 MWs of CCs to each MW of CTs for all market areas. In the Pacific Northwest, The NPPC, as part of its regional power planning responsibilities, keeps abreast of the latest construction and operating costs for all potential generating resources. The construction costs identified for CC plants of 250 MW capacity in the WSCC were estimated to be $601 per kW of installed capacity, at the 1998 price level. The average heat rate of new CC plants built in 1998 was assumed to be 7,045 Btu/kWh and was assumed to go down (gain efficiency) over time at a recent historical rate. The construction costs were based on the most current financing rates found in the industry.

Alberta, and British Columbia Hydro transmission areas, a 12 percent reserve margin was maintained, whereas in other areas including California, a 10 percent reserve margin was maintained in the PROSYM model.

In the PROSYM analysis both combined-cycle and combustion turbine technologies were considered as future resources in the WSCC. Annualized investment cost for CT units used in the model was 48.09 $/kw at the1999 price level. For CC units an annualized investment cost of 84.05 $/kw was used at the same price level. These costs represent a unit capacity of 240 MW and 120 MW, respectively for CC and CT units. Table 13 below contains the full capacity average heat rates used for each unit type. Note that the unit efficiency improves for CC units in future years as new innovations are made in the technology.

**Table 13.**
**Full Load Average Heat Rates**

| | **240 Mw** | **120 Mw** |
|---|---|---|
| Year | Heat Rate CC | Heat Rate CT |
| 2000-2004 | 7100 | 10500 |
| 2005-2009 | 6900 | 10500 |
| 2010 and forward | 6800 | 10500 |

***Combustion Turbine Costs and Technology.*** Because new capacity additions are comprised of entirely natural gas-fired combined-cycle (CC) powerplants, an effort was made to develop plausible and consistent assumptions regarding the evolution of the cost and performance of these plants over the study period.

Continuing advances in aerospace gas turbine technology are expected to lead to further reductions in the cost, and increases in the efficiency, of natural gas-fired power generation turbines. For this study, cost reduction assumptions are based on the projected improvement in gas turbine specific power[2] (increases in specific power produce greater output with no increase in physical size, thereby reducing cost). Historical rates of improvement and estimated ultimately achievable rates of specific power suggest that over the study period specific power will continue to improve at constant rates. The resulting projections of cost reduction averaged -0.6 percent per year for the medium forecast projection. This reduction

[2] Specific power is the power output per unit mass of working fluid.

was applied to both the capital and operating costs of new CC plants in the BPA and AURORA models. No adjustment was made in the PROSYM model.

***Unserved Load.*** In the BPA and AURORA models, power system simulations were performed with the amount of available energy to serve the power load varying substantially for the different water years. The models attempted to identify the most cost-effective way to serve the loads given the energy and generation resources available but not all of the load was served in each time period because there was either not enough energy or capacity available to meet demand. In the real world, if shortages like this occur, the system operators will start shedding loads to protect the stability of the system by not serving certain loads and/or by curtailing the amount of power provided to some electric customers. There will clearly be an economic cost associated with this shedding or curtailment. The approach used by the AURORA model to handle unserved load was to recognize that demand-side management measures could be instituted to reduce peak load during the critical hours when the full load cannot be served. The PROSYM model simply assigned an extremely high cost to the portion of the demand not met by available resources. This high value was assumed to represent a proxy for the economic cost of curtailment. Therefore, no demand-side voluntary actions were assumed in PROSYM.

The use of demand-side management measures was developed by the NPPC and used in the Lower Snake River Study. The same approach was used here for the AURORA model. It was assumed that the market could reduce up to 26 percent of the maximum peak load in any period through the voluntary actions of power consumers. The NPPC developed a supply curve for demand-side resources based on the best available information. This supply curve, used in both the BPA and AURORA models, is presented in Table 14 below. The table shows how different levels of the potential 26 percent reduction in peak load were priced in the analyses. For example, up to 20 percent of the 26 percent peak reduction could be met by reducing demand at a cost of 50 mills/kWh. The models dispatched these demand-side resources as proxies for actual generating resources at the prices shown. Further discussion on demand-side management is provided in Section 5.7.3.

**Table 14.**
**Demand-Side Supply Curve**

| Step | Share of Potential | Mills/KWh |
|---|---|---|
| 1 | First 20% | 50 |
| 2 | Second 20% | 100 |
| 3 | Third 20% | 150 |
| 4 | Fourth 20% | 250 |
| 5 | Last 20% | 500 |
| 6 | Unserved Peak | 1000 |

## 5.6. Net Economic Effects By Alternative

As described above, two different approaches were undertaken to estimate the net system economic effects associated with the impacts to hydropower production in the PNW—a system production cost approach and a market price approach.

## 5.7. System Production Costs Analysis

The economic effects provided in this section are based on the system production costs as defined by the BPA and Corps production cost models. In the Lower Snake River Study, a range of results was presented based on three projections of the key variables of fuel costs and power loads. These future conditions were referred to as the low, medium and high projections. Due to its limited scope, only the medium (most likely) projections of future conditions were investigated in this Phase I report. The interested reader can examine the results of the hydropower analysis for the Lower Snake River Study to gain an understanding of the significance of variations in the future projections of input variables. For USACE PROSYM model, the fuel cost and load assumptions are as stated in Section 5.5.3 of this study.

The terminology used here refers to variable and fixed costs, which correspond to energy and capacity, respectively. Energy is defined as the power (capacity) that does work over a time period. Electrical energy consumed is usually measured in kilowatt-hours (kWh), megawatt-hours (MWh), or annual average megawatts (aMW). Capacity is defined the maximum amount of power that can be delivered by a generating station. Electrical capacity is usually measured in kilowatts (kW) or megawatts (MW). In terms of system production costs, the variable costs are the costs associated with meeting the energy requirements. They go up and down with the level of energy produced and represent the per unit cost of energy generation. The fixed costs are the costs associated with providing the generation capacity and do not vary with the level of energy production. The fixed costs represent the annualized cost of constructing the new capacity.

***Variable Production Costs.*** The variable production costs of thermal-based energy generation mainly include the fuel costs and, to a less extent, other variable operating costs (consumables required to keep the machinery working, etc.). If energy is transmitted between market regions, the costs associated with this transmission are also included in the variable production costs. Table 15 shown below provides a summary of the variable production costs for the Without Project Condition (JD1) and Alternatives 3 and 4 (JD5), as estimated by the BPA model for the year 2020 using the medium forecast projection and the 50-year average water conditions (BPA uses a 50-year period of historical water conditions instead of USACE' 60-year period). This table is provided to demonstrate the nature of the variable production costs for the PNW and California. Similar results were computed for all the years from 2002 to 2024. Comparing the total variable production costs for year the 2020 between the Without Project Condition (JD1) and Alternatives 3 and 4 (JD5) shows that the variable costs increased by $142.3 million.

As shown in Table 15, the results of the BPA model are provided by resource type in the PNW. Some thermal plants in the PNW are classified as "must run thermal," due to the operating characteristics of the plant (i.e., nuclear plants) or long-term contracts that require a constant level of production. The energy generation from these plants does not vary with the different alternatives, so the variable costs are not included in the table. New CC plants were assumed to be constructed in the future, with more CC plants being built under Alternatives 3 and 4 (JD5) than under the Without Project Condition (JD1), to replace some of the lost John Day hydropower generation and capacity. Also shown are the resource types in the PSW. The resources in the PSW were aggregated into three types: Existing Resources, New Region

CC, and Curtailment/Demand-Side resources. Finally, the costs associated with transmitting energy between regions are also reported.

It is important to note how the losses in hydropower associated with the alternatives are accounted for by the BPA model. From Table 15, it can be seen that the HYSSR model estimated that with Alternatives 3 and 4 (JD5) that the amount of system hydropower production was reduced by 1,084 aMW between the two alternatives. This loss in hydropower generation was compensated for by a combination of thermal-based generating resources (primarily new natural gas-fired combined-cycle combustion turbines) at a higher cost. It is these added variable production costs that account for the overall increased production costs, which are a large component of the net economic effects.

Table 15 also shows that the total energy generation in the PNW will decrease by 153 aMW and the total energy generation in the PSW will increase by 154 aMW with the drawdown of John Day Dam to natural river levels. This essentially demonstrates that the PNW will import 153 aMW from the PSW in the year 2020 under the conditions of Alternatives 3 and 4 (JD5) as simulated by the BPA production cost model.

The variable costs for hydropower generation in the production cost model were assumed to be zero for all alternatives. This is because there is no cost of fuel for hydropower. It is recognized that there will be some differences in variable costs, fixed O&M, and capital costs for hydropower between the different alternatives, but these are not included in this power analysis. However, the implementation cost analysis does include these differences in hydropower O&M and capital costs with all alternatives and including them in this hydropower analysis would have resulted in double-counting this impact.

**Table 15.**
**System Production Costs Summary – Variable Costs Year 2020, BPA Model, Medium Forecast**

| VARIABLE PRODUCTION COST SUMMARY W/O PROJECT CONDITION | | | |
|---|---|---|---|
| **Type of Plant** | **aMW** | **Variable Costs (1998 $ Millions)** | **Average Var. Costs (mills/kWh)** |
| **PNW PLANTS:** | | | |
| High Cost Coal | 547 | 81.3 | 17.0 |
| Low Cost Coal | 2,432 | 203.4 | 9.5 |
| Existing CT | 48 | 10.4 | 24.9 |
| Existing CC | 1,564 | 224.8 | 16.4 |
| New Region CC | 9,681 | 1,202.5 | 14.2 |
| Regional Firm Imports | 1,480 | 117.3 | 9.0 |
| Regional Hydropower | 15,614 | - | - |
| Curtailment/Demand-Side | 65 | 44.5 | 78.5 |
| **TOTAL PNW:** | **31,431** | **1,884** | **13.6** |
| **PSW PLANTS:** | | | |
| Existing Resources | 6,832 | 1,445.5 | 24.2 |
| New Region CC | 9,449 | 1,299.5 | 57.6 |
| Curtailment/Demand-Side | 93 | 46.9 | 57.6 |
| **TOTAL PSW:** | **16,374** | **2,792** | **19.5** |
| **TRANSMISSION COSTS** | | **32.7** | |
| **TOTAL VARIABLE COSTS** | | **4,708.8** | |

| VARIABLE PRODUCTION COST SUMMARY WITH ALTERNATIVES 3 & 4 | | | |
|---|---|---|---|
| **Type of Plant** | **aMW** | **Variable Costs (1998 $ Millions)** | **Average Var. Costs (mills/kWh)** |
| **PNW PLANTS:** | | | |
| High Cost Coal | 539 | 80.1 | 17.00 |
| Low Cost Coal | 2,438 | 203.9 | 9.50 |
| Existing CT | 48 | 10.3 | 24.90 |
| Existing CC | 1,600 | 230.0 | 16.40 |
| New Region CC | 10,587 | 1,320.6 | 14.20 |
| Regional Firm Imports | 1,481 | 117.4 | 9.00 |
| Regional Hydropower | 14,530 | - | - |
| Curtailment/Demand-Side | 55 | 41.3 | |
| **TOTAL PNW:** | **31,278** | **2,004** | **13.6** |
| **PSW PLANTS:** | | | |
| Existing Resources | 6,883 | 1,473.5 | 24.40 |
| New Region CC | 9,551 | 1,297.1 | 14.90 |
| Curtailment/Demand-Side | 94 | 46.5 | 56.20 |
| **TOTAL PSW:** | **16,528** | **2,817** | **19.5** |
| **TRANSMISSION COSTS** | | **30.3** | |
| **TOTAL VARIABLE COSTS** | | **4,851.0** | |

**Table 15. (cont.)**
**System Production Costs Summary – Variable Costs Year 2020, BPA Model, Medium Forecast**

| DIFFERENCES FROM WITHOUT CONDITION (JD5 - JD1) | | | |
|---|---|---|---|
| **Type of Plant** | **aMW** | **Variable Costs (1998 $ Millions)** | **Average Var. Costs (mills/kWh)** |
| **PNW PLANTS:** | | | |
| Must Run 1/ | - | 1 | |
| High Cost Coal | (8) | (1) | |
| Low Cost Coal | 6 | 1 | |
| Existing CT | - | (0) | |
| Existing CC | 36 | 5 | |
| New Region CC | 906 | 118 | |
| Regional Import | 1 | 0 | |
| Regional Hydropower | (1,084) | - | |
| Curtailment/Demand-Side | (10) | (3) | |
| **TOTAL PNW:** | **(153)** | **119** | |
| **PSW PLANTS:** | | | |
| Must Run 1/ | | | |
| Existing Resources | 51 | 28 | |
| New Region CC | 102 | (2) | |
| Curtailment/Demand-Side | 1 | (0) | |
| **TOTAL PSW:** | **154** | **25** | |
| **TRANSMISSION COSTS** | | **(2)** | |
| **TOTAL VARIABLE COSTS** | | **142.2** | |

1/ The must run thermals, primarily nuclear plants, are not included because generation does not vary between alternatives.

***Fixed Production Costs.*** This section discusses the fixed production costs attributed to capacity construction costs. For either of the production cost models to meet the loads projected over time, new generating facilities will need to be constructed. With each alternative, a different quantity of new thermal-based generating facilities will be needed to account for the varying amounts of hydropower production. The decision of when and how much new capacity is to be built is a very important element of the analysis.

On a simplified basis, decisions about market-driven capacity additions will probably be based on the following considerations.

The market-clearing price of power for any selected time period will generally be based on the marginal costs of the last resource. Only during periods of extremely high demand (peak demand), typically on very hot summer (or cold winter) days, when the demand for electricity approaches the available generating capacity, would power prices rise above the marginal costs of the most expensive generating unit operating. Because the total amount of capacity available at any point in time is fixed, and new generating capacity cannot be built quickly, the only way in which demand and supply could be kept in balance during extremely high demand periods would be through an increase in the price, to a level that would encourage some consumers to reduce their power usage. The frequency of occurrence of these periods of high prices will help determine whether new generating resources will be built. The price adjustments during periods of peak demand can be thought of as representing the value consumers place on reliability.

This power price signaling concept and its frequency of occurrence formed the decision criteria for construction of new thermal-based generating resources in the BPA and AURORA models used in this power analysis. With these models, new resources are added when the marginal costs for power are sufficiently high frequently enough to cover the cost of constructing the resource (in terms of the annualized fixed costs) and the variable operating costs. The BPA model, for example, first simulates each year without any new resources being added in that year, and then tests to see if it is economically justified to add new resources. Justification depends on whether a new generating resource can produce enough energy in that year at the marginal costs to equal or exceed the fixed and variable costs of the new resource. If the new resource is economically justified, it is added to the resource mix. The model continues this process until an optimized amount of new resources are identified.

This economic justification approach was used in this study to estimate how many new resources would be built with each of the study alternatives, on a year-by-year basis from the present to year 2020. The additional fixed costs are included as a component of the total system production cost for identifying the net economic effects of each alternative. These costs are similar to the traditional "capacity costs" identified in past studies. Table 16 presents the resource additions projected to occur based on the BPA model results. The BPA model gives capacity resources in terms of average annual megawatts and not in installed megawatts. From the discussion earlier, an annual megawatt represents a megawatt operating fully through the year. Since a new gas-fired power generating unit can, on average, only operate with approximately a 91-92 percent annual plant factor due to maintenance downtime, it follows that the additional resources presented in aMW units have to be adjusted by a factor of 1.09 (1.00/0.92) to convert them to installed MW units. As can be seen from this table, it was estimated that 20,220 aMW of new generating capacity would be built in the PNW and PSW for the Without Project Condition (JD1) by the year 2020. With Alternatives 1 & 2 (JD2) an additional 420 aMW (or 460 MW) would have to be added by year 2020. With Alternatives 3 & 4 (JD5) it was estimated that 880 aMW (or 960 MW) would have to be added by year 2020.

As noted earlier it was assumed that this new capacity would be provided from natural gas-fired combined-cycle combustion turbine (CC) plants at a cost of approximately $601 per kW and average plant size of 250 MW.

| Table 16. Resource Additions By Alternative | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Study** | **Power** | **2014** | | | **2020** | | |
| **Alternative** | **Scenario** | **PNW** | **PSW** | **TOTAL** | **PNW** | **PSW** | **TOTAL** |
| | | (aMW) | (aMW) | (aMW) | (aMW) | (aMW) | (aMW) |
| **Without Project Condition** | JD 1 | 7,510 | 5,790 | 13,300 | 10,060 | 10,160 | 20,220 |
| **Alternative 1&2** | JD 2 | 7,900 | 5,820 | 13,720 | 10,450 | 10,190 | 20,640 |
| | JD 3 | 8,750 | 5,860 | 14,610 | 11,300 | 10,310 | 21,610 |
| | JD 4 | 8,720 | 5,870 | 14,590 | 11,270 | 10,310 | 21,580 |
| **Alternative 3&4** | JD 5 | 8,320 | 5,810 | 14,130 | 10,840 | 10,260 | 21,100 |
| | JD 6 | 9,040 | 5,920 | 14,960 | 11,580 | 10,310 | 21,890 |
| | JD 7 | 8,670 | 5,930 | 14,600 | 11,230 | 10,330 | 21,560 |

| DIFFERENCE FROM WITHOUT CONDITION (aMW) | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Without Project Condition** | JD 1 | - | - | - | - | - | - |
| **Alternative 1&2** | JD 2 | 390 | 30 | 420 | 390 | 30 | 420 |
| | JD 3 | 1,240 | 70 | 1,310 | 1,240 | 150 | 1,390 |
| | JD 4 | 1,210 | 80 | 1,290 | 1,210 | 150 | 1,360 |
| **Alternative 3&4** | JD 5 | 810 | 20 | 830 | 780 | 100 | 880 |
| | JD 6 | 1,530 | 130 | 1,660 | 1,520 | 150 | 1,670 |
| | JD 7 | 1,160 | 140 | 1,300 | 1,170 | 170 | 1,340 |

| DIFFERENCE FROM WITHOUT CONDITION (MW) | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Without Project Condition** | JD 1 | - | - | - | - | - | - |
| **Alternative 1&2** | JD 2 | 420 | 30 | 460 | 420 | 30 | 460 |
| | JD 3 | 1,350 | 80 | 1,420 | 1,350 | 160 | 1,510 |
| | JD 4 | 1,320 | 90 | 1,400 | 1,320 | 160 | 1,480 |
| **Alternative 3&4** | JD 5 | 880 | 20 | 900 | 850 | 110 | 960 |
| | JD 6 | 1,660 | 140 | 1,800 | 1,650 | 160 | 1,820 |
| | JD 7 | 1,260 | 150 | 1,410 | 1,270 | 180 | 1,460 |

1/ Includes all capacity additions up to and including this year.

### 5.7.1. Total System Production Costs

Table 17 summarizes the increase in total system production costs for the various alternatives (column 6) when compared to the Without Project Condition for year 2020, using the medium projection forecast, and the average over all water years. The increase in total system production costs include the variable costs of operating all the resources in year 2020 (column 3) and the fixed costs (column 5) associated with the addition of new resources that are needed to meet the projected power load. The increase in variable costs in any given year include the increased operating costs for all the resources in the system, including the resources added that year, while the increase in fixed costs are the annualized capital costs of the new capacity only. For example, for the Alternatives 3 & 4 (JD5), 880 aMW of new capacity was added up to year 2020 over the Without Project Condition (JD1). The increase in annual fixed costs for this additional capacity was 91 million. The total system production costs in 2020 for Alternatives 3 and 4 (JD5) were the combination of the variable costs of of $142 million and the fixed costs of $91 million. The total system production cost ranged from $207 to $233 million.

**Table 17.**
**Summary of Increase in Total System Production Cost**
**Year 2020 Simulation - Medium Forecast Projection**
**Costs Compared to Without Project Condition**

| 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|
| **Study** | **Power** | **Increase in Variable Production Costs (1998 $ Million)** | **Increase in CC Capacity (aMW)** | **Increase in Annual Fixed Costs (1998 $ Million)** | **INCREASE IN TOTAL SYSTEM PRODUCTION COSTS (1998 $ Million)** |
| **Alternative** | **Scenario** | | | | |
| | | | | | |
| **Alternative 1&2** | JD 2 | 74 | 420 | 44 | 118 |
| | JD 3 | 234 | 1390 | 145 | 379 |
| | JD 4 | 233 | 1360 | 142 | 375 |
| **Alternative 3&4** | JD 5 (BPA) | 142 | 880 | 91 | 233 |
| | JD 5 (COE) 1/ | | 880 | | 207 |
| | JD 6 | 325 | 1670 | 175 | 500 |
| | JD 7 | 323 | 1340 | 140 | 463 |

1/ Includes all capacity additions up to and including this year. This is average MW. To determine total new capacity divide by the availability factor of 92%. For example, for JD5 the new capacity up to and including 2020 is approximately 960 MW.

2/ Variable and fixed costs were not separately identified for the COE analysis.

Note: For COE analysis, increase in capacity required to replace John Day capacity based on a combination of 70% CC and 30% Combustion Turbine (CT) capacity.

Table 18 shown below presents the increase in system production costs on a year-by-year basis for the medium forecast projection. This table also provides the total present worth values of these costs for each alternative and the average annual costs based on the FY-99 Federal Interest Rate of 6.875 percent. The year 2013 was considered to be the first year with hydropower impacts, and it was assumed that the increase in annual system production costs as defined for year 2020 would be constant until the end of the period of analysis in the year 2110.

| **Table 18.**<br>**Total System Production Costs Over Time**<br>**Differences From Without Project Condition**<br>**1998 Real Million Dollars, Starting at In-Service Date of 2013**<br>**Medium Forecast Projection** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | **BPA MODEL** | **PROSYM** | | |
| **Study Alternatives** | **Alternatives 1&2** | | | **Alternatives 3&4** | **Alternatives 3&4** | | |
| **Power Scenarios** | JD 2 | JD 3 | JD 4 | JD 5 | JD 5 | JD 6 | JD 7 |
| **YEAR:** | | | | | | | |
| 2013 | 112.5 | 361.5 | 357.3 | 222.9 | 223.4 | 477.1 | 442.3 |
| 2014 | 113.2 | 363.9 | 359.7 | 224.3 | 223.0 | 480.1 | 445.3 |
| 2015 | 114.0 | 366.3 | 362.1 | 225.8 | 222.6 | 483.4 | 448.6 |
| 2016 | 114.8 | 368.8 | 364.5 | 227.3 | 219.3 | 486.7 | 451.8 |
| 2017 | 115.6 | 371.3 | 367.0 | 228.8 | 216.1 | 489.8 | 454.8 |
| 2018 | 116.3 | 373.9 | 369.5 | 230.3 | 212.9 | 493.0 | 457.7 |
| 2019 | 117.1 | 376.5 | 372.0 | 231.7 | 209.7 | 496.3 | 460.5 |
| 2020 - 2110 | 118.0 | 379.0 | 374.6 | 233.1 | 206.5 | 499.5 | 463.4 |
| **RESULTS:** | | | | | | | |
| **NPV at 6.875%** | 1695 | 5448 | 5384 | 3353 | 3065 | 7182 | 6663 |
| **Avg Annual at 6.875%** | 117 | 375 | 371 | 231 | 211 | 494 | 459 |

### 5.7.2. Market Price Analysis

The electric industry is moving rapidly towards a more competitive market, but is currently in a transition period which mixes wholesale pricing at marginal costs with most retail pricing based on average costs, and established contracts that may or not reflect either of these approaches. For these reasons, this report provides results from the two approaches of system production costing discussed in the previous section and the market pricing discussed in this section.

In this market pricing analysis, the market prices from AURORA and PROSYM, as defined by the marginal costs, are applied to the differences in PNW hydropower generation between the study alternatives and the Without Project Condition (JD1). Since the marginal costs (market prices) vary by transmission area and by time period, the study team had to select which market prices would be most appropriate to evaluate impacts. Changes in PNW hydropower generation were multiplied by the AURORA market price developed for the states of Oregon and Washington, or PROSYM market prices developed for the Pacific Northwest, for the Without Project Condition. These prices most accurately reflect the value of PNW energy. These marginal costs vary by hour, by day, by month, and by year. To simplify the analysis, hourly prices were allocated to peak and non-peak periods and averaged for each month to obtain estimates of peak and off-peak prices. Table 19 shown below provides the monthly average on-peak and off-peak market prices determined by AURORA and PROSYM, for the medium forecast projection, for the two specific years of 2013 and 2020, in nominal prices and real 1998 dollars.

The average monthly prices for peak and non-peak were used to identify the economic effects associated with changes in hydropower generation for the various alternatives. This was done by computing the change in hydropower generation from the current conditions, by subtracting the PNW hydropower generation with each alternative from the Without Project Condition. Adjustments were also made to the monthly hydropower generation by separating it into peak and non-peak hours based on the historic distribution shaping of the monthly hydropower generation. Table 20 presented the hydropower generation changes for each alternative based on average monthly generation.   Table 20 multiplies the projected market price for each year by the changes in hydropower output from the base condition using the hydro-regulation model outputs. This table labels the economic effects as net economic costs to represent changes from the without condition. The last row of Table 20 provides the average annual net economic costs based on the FY-99 Federal Interest Rate of 6.875 percent, a 100-year period of analysis, and power impacts starting in year 2013. The lower section of this table presents a comparison of the results based on the AURORA and PROSYM models for the year 2020.

**Table 19.**
**Average Market-Clearing Prices From AURORA & PROSYM Prices for Two Years in 1998 $ (mills/kWh)**
**YEAR 2013**

| | AURORA MODEL | | PROSYM MODEL | |
|---|---|---|---|---|
| **Month** | **On-Peak** | **Off-Peak** | **On-Peak** | **Off-Peak** |
| SEP | 29.06 | 18.89 | 34.23 | 19.63 |
| OCT | 22.03 | 17.74 | 41.01 | 23.83 |
| NOV | 23.18 | 18.53 | 41.35 | 26.85 |
| DEC | 25.77 | 21.44 | 43.24 | 27.85 |
| JAN | 25.96 | 22.67 | 44.87 | 27.15 |
| FEB | 24.12 | 19.79 | 38.43 | 22.81 |
| MAR | 21.51 | 15.64 | 27.28 | 18.12 |
| APR | 18.22 | 12.10 | 24.31 | 15.26 |
| MAY | 11.44 | 11.42 | 23.54 | 13.38 |
| JUNE | 15.13 | 10.60 | 20.42 | 10.28 |
| | **AURORA MODEL** | | **PROSYM MODEL** | |
| **Month** | **On-Peak** | **Off-Peak** | **On-Peak** | **Off-Peak** |
| JULY | 14.91 | 16.53 | 26.70 | 14.62 |
| AUG | 28.10 | 23.47 | 35.95 | 20.70 |
| AVG. | 21.67 | 17.40 | 34.23 | 19.63 |

**YEAR 2020**

| | AURORA MODEL | | PROSYM MODEL | |
|---|---|---|---|---|
| **Month** | **On-Peak** | **Off-Peak** | **On-Peak** | **Off-Peak** |
| SEP | 31.16 | 21.49 | 29.17 | 16.05 |
| OCT | 24.20 | 17.79 | 33.07 | 20.51 |
| NOV | 26.49 | 18.66 | 37.81 | 23.03 |
| DEC | 33.01 | 23.60 | 41.21 | 24.77 |
| JAN | 31.74 | 23.35 | 40.05 | 22.77 |
| FEB | 25.35 | 20.83 | 27.04 | 17.67 |
| MAR | 23.69 | 18.55 | 23.91 | 15.50 |
| APR | 20.73 | 13.44 | 20.76 | 13.86 |
| MAY | 14.21 | 13.55 | 21.13 | 12.45 |
| JUNE | 17.49 | 12.78 | 19.01 | 10.85 |
| JULY | 25.20 | 19.96 | 23.20 | 13.12 |
| AUG | 30.56 | 24.74 | 27.34 | 16.43 |
| AVG. | 25.32 | 19.06 | 29.17 | 16.05 |

**Table 20.**
**Increase in Net Economic Costs Computed From AURORA Market Prices**
**(Market Clearing Price Multiplied By Change in Hydropower)**
**Differences from Without Project Condition**
**1998 Real Million Dollars, Starting at In-Service Date of 2013**
**Medium Forecast Projections**

| Study Alternative | Alternatives 1&2 | | | Alternatives 3&4 | | |
|---|---|---|---|---|---|---|
| **Power Scenario** | **JD 2** | **JD 3** | **JD 4** | **JD 5** | **JD 6** | **JD 7** |
| **YEAR** | | | | | | |
| 2013 | 103.9 | 324.9 | 319.1 | 208.4 | 433.3 | 398.9 |
| 2014 | 103.9 | 324.2 | 318.3 | 208.4 | 432.5 | 394.6 |
| 2015 | 102.2 | 318.7 | 312.5 | 205.1 | 425.4 | 385.3 |
| 2016 | 104.2 | 325.2 | 319.2 | 209.1 | 433.6 | 400.3 |
| 2017 | 101.6 | 316.9 | 310.9 | 203.9 | 422.6 | 387.9 |
| 2018 | 102.4 | 319.9 | 314.2 | 205.5 | 426.8 | 393.0 |
| 2019 | 99.1 | 309.5 | 304.0 | 198.5 | 412.5 | 377.9 |
| 2020 | 100.4 | 314.7 | 309.7 | 201.1 | 419.5 | 388.2 |
| 2021 - 2112 | 100.4 | 314.7 | 309.7 | 201.1 | 419.5 | 388.2 |
| | | | | | | |
| **RESULTS:** | | | | | | |
| | | | | | | |
| **NPV at 6.875%** | 1470.6 | 4602.7 | 4525.0 | 2947.2 | 6136.2 | 5658.4 |
| | | | | | | |
| **Avg Annual at 6.875%** | 101.2 | 316.8 | 311.5 | 202.9 | 422.4 | 389.5 |

**COMPARISON IN INCREASE OF NET ECONOMIC COSTS FOR AURORA AND PROSYM**
**ANNUAL COSTS COMPARED TO WITHOUT PROJECT CONDITION (1998 $ Millions)**
**Year 2020 Simulation**

| Study Alternative | Alternatives 1&2 | | | Alternatives 3&4 | | |
|---|---|---|---|---|---|---|
| **Power Scenario** | **JD2** | **JD3** | **JD4** | **JD5** | **JD6** | **JD7** |
| | | | | | | |
| **AURORA PRICES** | 100.4 | 314.7 | 309.7 | 201.1 | 419.5 | 388.2 |
| **PROSYM PRICES** | 110.9 | 346.6 | 339.5 | 222.3 | 462.9 | 410.0 |
| **Difference Between Models** | 10.5 | 31.8 | 29.8 | 21.2 | 43.4 | 21.8 |
| **Percentage Difference (%)** | 10 | 10 | 10 | 11 | 10 | 6 |

### 5.7.3. Reliability and Capacity Effects.

Of particular interest to this analysis is how the generation reliability in the PNW and WSCC will be affected by the hydropower capacity reductions resulting from the implementation of the study alternatives. To what extent additional thermal-based capacity will be needed to replace the lost hydropower capacity is of particular interest from an economic standpoint.

Several important elements of this generation reliability approach had to be considered by the study team. The principal points of consideration in this analysis were:

- The treatment of power load in periods in which existing resources were insufficient to meet load demand
- Consideration of system reserves requirements and dependable capacity
- Type and cost of new resources

These concerns relate to how the lost hydropower capacity will be replaced with replacement generating resources. In the Lower Snake River Juvenile Salmon Migration Feasibility Study (Lower Snake River Study) these issues were studied in detail. For a detailed description of what was done in this study, the interested reader is referred to Section 5.4, of the Lower Snake River Juvenile Salmon Migration Feasibility Study report, "*Technical Report on Hydropower Costs and Benefits, 31 March 1999"*. The following discussion provides an overview of how the reliability and capacity effects were addressed in the Lower Snake River Study, which provided the basis for the analysis used in the John Day Dam Drawdown Study.

**Conceptual Considerations.** Generation reliability can be evaluated in numerous ways, but all approaches are generally based on how well the available generating resources can meet the power load in all time periods. In the PNW, the generation reliability of the power system primarily depends on the availability of water for producing hydropower. In other systems throughout the nation, in which hydropower is a very small component of the total power generating resource mix, planned and forced outages of thermal-based power plants are more important determining factors for reliability. So, to determine the generation reliability in the Lower Snake River Study, the probable range of hydraulic conditions were examined using the system hydro-regulation models HYSSR and HYDROSIM (the BPA hydro-regulation model).

The scheduled (planned) and unscheduled (forced) outages of resources are a significant component of any generation reliability analysis. The power system models used in the analysis account for the forced outages by either including random outages or de-rating the units. For example, the BPA model de-rates the new CC units by three percent to account for the probability of planned outages and an additional five percent to account for the probability of unscheduled outages. The PROSYM model incorporates planned and forced outages on a unit-by-unit basis based on outage rates common to the different type of resources.

Traditionally, the PNW generation reliability has been defined considering the dependable capacity of the hydropower system based on critical-year water conditions and high power demand periods. This type of "firm planning" analysis has taken several forms over the years, all of which were geared towards assuring that power loads are met with available generation with a high level of probability. PNW hydropower dependable capacity has been defined in different ways in past studies. For example, the dependable capacity has been based on various extremely low streamflow conditions associated with, (1) the historic water conditions of the 42-month interval from September 1928 through February 1932, (2) the hydropower capability with January 1937 water, (3) sustainable capacity over 50 hours of operation per week based on January 1937 water and load conditions, and (4) instantaneous capacity with different water conditions. Under these traditional approaches, if study alternatives reduced the hydropower dependable capacity, it was assumed that new capacity would be built to replace the exact amount of lost dependable capacity. This approach was not used in this analysis, or in the Lower Snake River analysis, but it is discussed below in the section entitled "System Reserves and Dependable Capacity Examination" to examine how the study results could change with a more traditional study approach.

As with other issues addressed in this report, the nationwide movement to a competitive electricity market affects how the issue of reliability and replacement capacity are analyzed. With less regulation of the electrical industry and the emergence of more independent power producers, many experts feel that market conditions will be the driving force to determine when new generating resources will be built. For the Lower Snake River and John Day Dam Drawdown analyses, it was assumed that in a competitive market, the decision to build new resources would be based on economic return rather than some regulatory convention. This assumption provided the conceptual foundation for the reliability and replacement capacity discussion of both reports. Ultimately, as the deregulated power market develops, the decision to build new resources will probably be based on a combination of economic return with some regulation to ensure that a reasonable level of system reliability is maintained. Further discussion about market driven capacity addition decisions can be found in this section of this report under the sub-section titled "Fixed Production Costs".

**Unserved Load and Demand-Side Resources.** The model simulations of the PNW and WSCC systems identified time periods in which the projected power loads exceeded the amount of power available. When these situations occurred, the models reported this as unserved load, and the number of megawatt hours not served was tabulated. In general, unserved loads occurred in the model simulations during low streamflow periods of the year, in low streamflow years, and in periods of high power demand. The frequency and magnitude of these unserved loads are discussed below. A critical element of the generation reliability analysis is how these unserved loads are treated.

One approach considered for the treatment of unserved loads in this analysis was to assume that a curtailment in power generation will occur with electricity consumers suffering the economic losses. The appropriate economic value to assign to this curtailment is not known, but in some studies it has been assigned a relatively high value that exceeds the marginal costs of all thermal-based generating resources. This approach was used in the PROSYM model and was tested with the BPA model. This is discussed below in the sub-section titled "Test of Unserved Load Approach".

The approach that was used with the BPA and AURORA models recognized that changes in power market prices will affect power demand. The models included demand-side management measures as potential resources to address unserved loads. This approach was chosen because, with the movement from average embedded cost pricing in regulated markets to marginal cost pricing in competitive markets, power prices are likely to be more volatile than historical average prices.

With average cost pricing, most consumers are unaware of the variation in operating costs across seasons and times of day. With competitive pricing, consumers and their suppliers may see more price volatility in the form of time-of-use prices, which will vary with the operating cost of producing power. This may create confusion for consumers, but it will also offer them the opportunity to reduce their electricity bills by altering the timing of their electricity use. Technologies are likely to develop to allow consumers, or their suppliers, to schedule their appliance usage to avoid high price periods. This analysis attempts to account for these probable demand-side resources in computing the capacity needs, market prices, and system production costs.

Instead of assuming that power curtailments will occur, the BPA and AURORA analyses assumed that demand-side actions would be taken first to meet some of the peak demands. Demand-side resources were priced in blocks with each successive block being more costly. The demand-side resources were treated like any other resource in the dispatching routines. During periods of high demand when thermal and hydropower resources are nearing full dispatch, the models dispatch the blocks of demand-side resources as needed to meet load. The demand-side resources are considered in defining the marginal costs and production costs in the two models. Since the demand-side resources are priced at relatively high levels, the extent to which they are dispatched will influence the optimizing routines and consequently help determine how many new resources would be built. For further discussion of the demand-side resources, the reader is referred to Section 5.4.2 of the Lower Snake River Study.

The BPA and AURORA models utilized the demand-side resources in the dispatch routines and the optimizing routine for additional resources. Table 16 shown previously in this report shows the amount of new thermal resources that were added by the BPA model for specific years of simulations, by alternative, and by the regions of the PNW and PSW. As explained before, all of these thermal resources were assumed to be natural gas-fired combined-cycle plants. The resources shown for the years 2010 and 2018 represent the cumulative amount of resources added up to the respective years. The table shows results in terms of average megawatts (aMW) and total MW of capacity added to the PNW and PSW.

**Test of Unserved Load Approach.** In the Lower Snake River Study, it was decided to test the treatment of unserved load and the economic value assigned to it. Of interest was how pricing unserved load and demand-side resources influenced the construction of new capacity.

The unserved load was met in the BPA and AURORA models by demand-side resources that were valued in blocks. The range of values (marginal costs) were from 50 to 500 mills/kWh depending on the size of unserved load. If any unserved load still occurred after dispatching all demand-side resources, it was assigned a marginal cost of 1,000 mills/kWh. It was determined that with these pricing assumptions, the demand-side resources were used infrequently to meet load.

To determine how significant these assumed block sizes and prices were, a test analysis was undertaken. In this test, simulations were run using the BPA model, replacing all the costs of demand-side resources and unserved loads with a cost of 5,000 mills/kWh. The test was done only for the year 2010 Without Project Condition (alternative A1) and the alternative where the Lower Snake River projects were drawn down to natural river levels (alternative A3). As expected, with this higher cost for unserved load, more new resources were found to be economical and were added by the model. The increase in the amount of new resources in the test case reflected that new resources could capture the high values to a large enough extent to economically justify their construction. That is, new resources could be justified with lower plant factors than in the original analysis.

The amount of new resource additions is not the only significant factor to examine. The total system production costs in the test and the original cases were also compared. The total system production costs with the test case increased significantly over the original case. These higher total system production costs were due to the costs of adding the new CC capacity. However, the variable production costs, relative to the original case, dropped in the test case because the new CC resources are more efficient and have lower variable costs than many of the existing resources in the resource mix. With more of these relatively efficient resources available for the model to dispatch to meet the load, the use of older resources with higher variable costs was reduced.

The changes in total system production costs between alternatives A1 and A3 under both cases yielded some interesting results. Generally, it was found that losing the Lower Snake River powerplants in a system with lots of excess capacity is not as costly as losing the plants in the original case.

In conclusion, this test showed that the treatment of the value of the unserved load in the BPA model influences the amount of new thermal resources that are added to the system. Assigning a very high value to unserved load will result in more new CC capacity and substantial increases in the total system production costs (variable costs + fixed costs). However, the increase in fixed costs are partially offset by the decrease in variable costs. It was found in both the original and test cases that the total system production costs increased with the removal of the Lower Snake River Dams. However, the value assigned to unserved load did somewhat influence the magnitude of the total system production costs associated with removing the dams. The significance of this influence appeared to be relatively small when compared to the substantial increase in the value of unserved load used in the test case. The next section examines the significance of capacity additions to total system production costs.

**System Reserves and Dependable Capacity Examination.** With any assessment of system reliability, criteria of acceptable reliability need to be devised and defined. Various criteria have been used historically in California and elsewhere in the West. These criteria have been different depending on the type of study and the time period of the study. One measurement tool has been the planning reserve margin, which is expressed as a percentage of installed generation capability in excess of maximum peak demand. The "correct" level of planning reserves in a deregulated power market has yet to be established. Many argue that this level should be an economic decision made by market participants.

The type of reliability criteria that may be developed in the future is hard to determine at this time. The WSCC has operated under a number of voluntary criteria and they are currently under examination for revision. For example, the WSCC has a Minimum Operating Reliability Criteria (MORC) that defines the goals of operating the system with adequate levels of generating reserves to account for a multitude of possible conditions. This sets criteria for operating reserves, spinning reserves, voltage control, reactive power support, transmission path restrictions, and numerous other operational considerations.

Currently, there is no legal authority to require any entity in the WSCC to participate in a mandatory reliability program with sanctions, but alternative approaches such as contractual agreements are being considered. The WSCC is examining new criteria to be implemented in the current open access market. This process is called the Reliability Management System (RMS) and is being implemented in three phases. In addition, at the national level, legislation is being developed for the North American Electric Reliability Council (NERC) to act as a policing authority similar to the Securities and Exchange Commission (SEC). Based on direction by FERC, there currently exist several Area Security Coordinators throughout the nation to assure system stability over all transmission areas.

Based on these proposals and their uncertainty, any attempt at this time to specifically define a set of reliability criteria would be subject to wide ranging criticism and would be likely to change before any of the Lower Snake River or John Day Dam Drawdown alternatives could be implemented. For this reason, the effects of the different reliability criteria on the net economic effects were examined. Specific details on the results of this examination can be found in Section 5.4.4 of the Lower Snake River Study.

The amount of additional CC generating capacity assumed to be built by the year 2010 under alternative A3 was computed by the BPA model to be 890 MW. The determination of alternative levels of new capacity additions to consider in this test was based on the more traditional dependable capacity approaches. The approaches used were: (1) To define a dependable capacity level of the existing Lower Snake River plants based on a recent study done by USACE. This study examined numerous criteria to define dependable capacity and recommended adding 2,640 MW to replace the four Lower Snake River dams. (2) The PROSYM model was used to identify the level of new CC capacity that would need to be in place by the year 2010 to maintain the PNW planning reserve margin at 12 percent for both alternatives A1 and A3. To achieve this level of reserve margin, A3 required an additional 3,250 MW of new capacity. The three different levels of new capacity were modeled with the BPA model to see how total system production costs (variable costs + fixed costs) would change. In addition, a scenario in which no additional resources were added above those assumed to occur with alternative A1 was also tested. The installed capacity additions discussed above were defined in terms of aMW for utilization in the BPA model. For example, the installed capacity for the scenarios of 0, 890, 2640, and 3250 in MW, were 0, 820, 2430, and 2990, respectively, in terms of aMW to account the 92 percent average availability rate of the new CC plants.

It can be concluded from this analysis that the addition of 890 MW of new capacity is at or near the point of optimum economic efficiency (point of minimal net economic costs). This was expected because the BPA model utilized an optimization routine to define the 890 MW level. The analysis suggests that the selection of the most appropriate level of new capacity may not be an extremely sensitive element of the hydropower study. For example, if the traditional dependable capacity approach was used the total system production costs would increase from $248 million to $273 million annually which is only a 10 percent increase. This increase in annual costs could be construed as the costs of improving system reliability.

This same type of analysis was done with the PROSYM model for alternative A3 with the new capacity additions of 890 MW, 2640 MW, and 3250 MW in the year 2010. The PROSYM model provides the planning reserve margin for each of the transmission areas in the model. The planning reserve margins for all regions except the PNW were the same for alternatives A1 and A3. The different levels of new capacity had planning reserves in the year 2010 of 4 percent, 10 percent, and 12 percent for the additions of 890 MW, 2,640 MW, and 3,250 MW, respectively. The total system production costs predicted with this model are higher than with the BPA model, but the same basic conclusion can be reached from the results of the PROSYM model. Selection of the capacity replacement level does not appear to be critical relative to the magnitude of the change in total system production costs.

**Reliability and Capacity Conclusions.** This section presented the basic elements of the analysis dealing with the addition of new generating capacity to replace the lost capacity associated with the breaching of the four Lower Snake River dams. The same procedures were used in the John Day Dam Drawdown Study. The replacement of the lost capacity relates to the general reliability of the power system over time, and to what extent the market might pay for additional reliability. One complicating element of these hydropower analyses was the projection of what society might pick as the most appropriate reliability criteria in the study period of 2005 and beyond. The approach used in these studies to estimate what level of new capacity would be built was to do an economic optimization to determine what level of new resources could be economically justified for construction. In addition, testing of the study results against other possible levels of new capacity and related generation reliability was completed.

There was concern whether different levels of replacement capacity and different approaches to the treatment of unserved loads would significantly change the estimates of increased system production costs. These two factors were tested with different approaches that lead to different levels on new capacity and planning reserve margins. With the higher levels of new generating capacity, the planning reserves were higher but so were the system production costs. However, it was found that the total system production costs did not vary significantly with the different levels of assumed new generating capacity. Therefore, the capacity addition approach used in this analysis represented a reasonable estimate of the economic effects associated with the study alternatives.

## 5.8. System Transmission Effects

The analysis of power system impacts up to this point assumed that transmission reliability and service would remain the same under all study alternatives. The purpose of this section is to estimate the costs associated with maintaining transmission reliability with the different power analysis scenarios.

No new transmission system impact study was done for this Phase I report to address the four specific alternatives being examined. The transmission analysis done for the ongoing study, *The Lower Snake River Juvenile Salmon Migration Feasibility Report*, by the Walla Walla District of the Corps of Engineers, is summarized here to estimate the transmission effects associated with John Day drawdown. The primary source of information for the Snake River transmission analysis is the January 1999 report, “Transmission Impacts of Breaching the Lower Snake and John Day Dams.” This report was prepared by the Transmission Business

Line (TBL) organization of BPA, and is available at the website address: http://www.transmission.bpa.gov/orgs/opi/system_news/lsd_sum.doc.

Unfortunately, the BPA transmission study did not estimate the transmission effects associated with only the drawdown of John Day Dam to the spillway or natural river levels. All the alternatives studied included the breaching of the four Lower Snake Dams, either by themselves or in combination with the drawdown of John Day Dam to spillway and natural river levels. Hence, transmission impacts are not available for Alternatives 1 & 2 (JD2) and Alternatives 3 & 4 (JD5). In other words, for this analysis it was not possible to isolate the transmission costs associated only with the John Day drawdown. However, the incremental transmission-related costs associated with drawing down John Day Dam subsequent to the breaching of the four Lower Snake River dams can be estimated. If the four Lower Snake Dams are breached before the drawdown of John Day Dam, then several transmission system reinforcement measures would have already been instituted, and the marginal requirements due to the John Day Dam drawdown would be less. It must be recognized that these incremental costs significantly understate the probable transmission costs associated with the John Day drawdown if the Lower Snake River dams are not also breached. It should be noted that USACE studies with PROSYM estimated that 2,400 MW of replacement thermal capacity would be added to replace the John Day capacity under Alternative JD5. However, the transmission impacts were not analyzed for USACE analysis. It is expected that the transmission impacts might be much different for this analysis given the larger amount of replacement capacity assumed.

To compute the incremental costs associated with transmission impacts of John Day Dam drawdown combined with the breaching of the Lower Snake River projects, we must first determine the transmission cost impacts associated only with the breaching of the Lower Snake River projects. From the Lower Snake River study, the average annual transmission impacts costs for breaching the four Snake River dams were $21.9 million to $28.1 million at the 6.875 percent discount rate.

The analysis of power system effects up to this point assumed that transmission reliability and service would remain the same under all alternatives. The purpose of this section is to estimate the costs associated with maintaining transmission reliability with the different power scenarios.

The breaching of John Day Dam and/or the four Lower Snake dams renders the powerhouses inoperable, thereby altering the configuration of power generation facilities in the PNW transmission grid that feeds into the Northwest transmission grid. Since the transmission grid was originally constructed in combination with the generation system, and since they interact electrically, loss of generation will affect the transmission system’s ability to move bulk power and serve regional loads.

The transmission analysis looked at transmission system impacts with and without replacement generation. Both transmission system reinforcements and generation additions were evaluated to mitigate the transmission system impacts caused by breaching the dams. The initial phase of this transmission study assumed no replacement generation for the dams that are breached. The transmission improvements needed to maintain reliable service were then identified and costs estimates were prepared. However, it was recognized that the construction and location of replacement generating resources would have a profound effect on the transmission system impacts and reinforcement needs and may provide a most cost-effective solution. This phase of the study was done separately from the energy supply additions shown in Table 16. The energy supply studies indicated that Alternatives 1 & 2 (JD2) required 460 MW of new CC generation in 2020 to replace lost hydropower capacity. Alternatives 3 & 4 (JD5) required 960 MW of new CC plants. This transmission study evaluated transmission system requirements if replacement generation were constructed in a location where it would provide the maximum transmission system benefits to mitigate the loss of hydropower capacity. To the extent that more than 960 MW of new CC generation will be required for greater transmission reliability, the additional costs are added to the transmission impacts. It should be noted that the PROSYM analysis identified a capacity replacement need of 2,400 MW in Alternatives 3 and 4, however, for comparison purposes the PROSYM results presented in this report were based upon the assumption of 960 MW of replacement capacity used in the other models. No transmission studies were done using the 2,400 MW replacement capacity assumption from PROSYM, but it is expected that using this assumption of additional replacement capacity would change the results of the transmission studies.

Preliminary cost estimates for capital additions are included in this summary. These costs are based on preliminary studies using typical costs for facilities. A range of costs is given since there is much uncertainty about the scope of the projects, routes, etc which could affect project cost.

Transmission impacts were examined for two seasonal conditions, the summer and the winter peak periods. The following defines the expected impacts and the possible solutions. The study approach was to first identify the impact to the transmission system; then the possible solutions were examined. The final step of the analysis was to select the most cost-effective measure to address the identified transmission impact.

**Summer Impacts.** The summertime peaks are the largest in the PSW and transmission from the PNW over the California-Oregon Intertie/Pacific Direct Current Intertie (COI/PDCI) is important to meeting the PSW demands.

***Pacific Northwest to California Transfers.*** If the Lower Snake River and John Day dams are breached, and no other generating capacity is added, the COI/PDCI transfers limits decrease by 1800 MW (from 7200 to 5400 MW). This would limit the ability to sell and transfer PNW generation to the PSW to meet peak demands. If the John Day Dam is drawn down to spillway level and the Lower Snake River dams are breached, the COI/PDCI transfer capability would be reduced by approximately 1000 MW. Three possible solutions were examined and are shown in Tables 21 and 22 . Summer solutions to the NW to California impacts were not studied because it was discovered that the solutions to the winter problems could also correct the summer problems.

***Summer Load Service.*** The Tri-Cities area, south of Spokane and central Washington load areas are negatively affected by the various pool drawdown and dam removal scenarios. Specific transmission impacts are different depending on the location of replacement generation. Regardless, possible remedies include constructing the new Schultz-Hanford line at a cost of $50 to $75 million and re-conducting or rebuilding other lower voltage lines at an estimated cost of $10 to 20 million. Additional voltage support is also needed in the Tri-Cities area if the four Lower Snake River dams are breached. Converting the generators at a hydropower plant to synchronous condensers is an effective way to produce reactive support required to fix this voltage support problem for Tri-Cities area loads. This could be accomplished with converting the generators at Ice Harbor Dam. Preliminary cost estimates for this conversion were $2 to $6 million. A similar voltage stability problem would occur if the John Day Dam is breached.

### Winter Impacts

The impacts to the transmission system under extreme winter load conditions in the PNW were examined. An extreme cold winter load condition was examined since stress on the system is high under extreme weather. The extreme cold winter load level is defined as an abnormally cold condition (arctic express) with minimum temperatures that have a 5 percent probability of occurring. The extreme cold winter load level is approximately 12 percent higher than the expected normal winter peak that has a 50 percent probability of occurring. BPA customers have agreed on these criteria in the past.

It was found that power imports from the California interties transmitted over the COI/PDCI could not meet the power shortfall created by the loss of the Lower Snake River projects and/or the John Day dam. The existing import capability on the COI/PDCI with the dams operating normally is around 2,400 MW during extreme winter load conditions. This 2,400 MW capability is currently needed to augment the available power generation and spinning reserve requirements in the PNW. Without the four Lower Snake River and John Day dams, either more intertie capability, and/or more local generation is required to meet system loads and maintain transmission system reliability. The possible solutions examined were to increase the capability of the COI/PDCI and/or develop adequate replacement generation capacity.

***PNW Replacement Generation.*** With the removal of the Lower Snake River and John Day dams, it was determined that approximately 1,000 MW of new generating resources (replacement generation), strategically located in the PNW, would be required over and above the new CC resources projected for the without project condition (JD1) shown in Table 25. In addition to the new 1,000 MW of generation, the COI/PDCI transmission system reinforcements discussed below will also be required.

The 1000 MW of new capacity assumed to be built in the future to maintain the system transmission reliability will need to be constructed at about the same time the dams are breached. It was found in the power system studies presented earlier in this document, that between 960 MW and 1,820 MW of additional CC capacity was assumed to be built by the year 2020 for the power Alternatives JD3, JD4, JD5, and JD6. Consequently, if these new CC plants are strategically located no additional generating resources will need to be built to mitigate the transmission system impacts for these study alternatives, if, and only if the improvements to COI/PDCI are also made.

***Improvements to COI/PDCI.*** The concurrent solution to building new replacement capacity is reinforce the intertie transmission system. The improvements needed to meet load service requirements for extreme winter conditions include: a second Captain Jack-Meridian 500-kV line (a cross cascades line from Klamath Falls to Medford) and a second Big Eddy-Ostrander 500-kV line (a cross cascades line from The Dalles to Portland). Both of these new transmission line additions need to be on separate right–of-way from the existing lines due to reliability considerations. The construction costs for a second Captain Jack-Meridian line were estimated at $80 to $130 million. The addition of a second Big Eddy-Ostrander line would cost from $70 to $120 million. The average annual costs of these two lines considering O&M, replacements, and repair, were computed at $5.6 to $9.0 million for Captain Jack Meridian and $4.9 to $8.3 million for Big Eddy-Ostrander, using the FY-99 Federal Interest Rate of 6.875 percent.

### 5.8.1. Summary of Transmission Impacts

Table 21 provides the possible solutions and related annual costs for power scenarios JD3 and JD4 based on the FY-99 Federal Interest Rate of 6.875 percent. Table 22 provides this same data for power scenarios JD6 and JD7. These tables are broken into the impact areas and possible solutions. For each impact, the lowest cost solution is recommended and included in the net economic effects presented in the last column. As can be seen, the only difference in transmission system impacts between these alternatives is the extent of impact to the COI/PDCI. Since it is assumed that the COI/PDCI would be improved with any of these alternatives, the transmission-related net economic effects are the same for scenarios JD3, JD4, JD6, and JD7. The annual costs are $23.5 to $36.5 million. The incremental costs of John Day drawdown combined with the breaching of the Lower Snake River dams was computed by subtracting the transmission costs estimated in the Lower Snake River study which were $21.9 million to $28.1 million at the FY-99 Federal Interest Rate of 6.875 percent discount rate. Hence, the incremental costs associated with adding John Day drawdown to the Lower Snake River dam breaching is $1.6 to $8.4 million.

The question that has not been answered is “What are the transmission system economic impact costs related to just the drawdown of John Day without the breaching of the Snake River dams (the effects of Alternatives 1, 2, 3 and 4).” This question was not answered for this Phase I Report due to the limited scope of the analysis. As an absolute minimum, the incremental costs discussed above could be used to estimate an extreme lower bound of the transmission-related impacts. However, it is the opinion of system operators that the impacts to the transmission system of drawing down John Day to the natural river level would be similar to the impacts associated with breaching the Lower Snake River dams. Many of the same type of transmission facility improvements would be necessary with the removal of John Day as with the removal of the four Lower Snake River dams. However, no studies have been completed to confirm this hypothesis. For this reason, the transmission impacts for Alternatives 3 & 4 (JD5), the two alternatives that lower John Day to the natural river level, were assumed to be the same as those estimated for the breaching of the Lower Snake River projects. The range of impacts would be between $21.9 million and $28.1 million. No studies were done to estimate the economic costs of transmission system impacts for Alternatives 1 & 2 (JD2). However, to account for the likely costs that would occur, it was assumed that the costs would range between the lowest incremental costs discussed in the last paragraph, and the lowest of the costs for the Lower Snake River breaching transmission impacts. That is, it was assumed that drawing down the John Day Dam to the spillway level would have economic costs associated with transmission impacts of between $1.6 million and $21.9 million. It is recognized that there is a great deal of uncertainty in these estimates. To improve the estimate, additional studies will be needed. Nevertheless, these conservative estimates discussed above are provided to represent a reasonable "place-holder" in the economic analysis. Table 23 summarizes the average annual costs of the transmission system impacts for each of the alternatives and scenarios.

**Table 21.**
**Transmission Impacts with John Day at Spillway & 4 Snake Dams Breached**
**Power Alternatives JD3 & JD4**
**Annual Values Based on 6.875%**

| Timing/Location of Impacts | Impact Description | Possible Solutions | Estimated Construction Costs ($millions) | Incremental O&M Costs ($millions) | Total Annual Costs ($millions) | Selected Solution Aver Annual Costs ($millions) |
|---|---|---|---|---|---|---|
| Summer: NW to California | Transfer limit is reduced (a cutplane problem) | Limit COI/PDCI transfer capability from 7200 MW to 6200 MW | Not quantified | | | |
| | | Upgrade the COI/PDCI | 65 to 85 | 0.3 | 5.1 to 5.9 | Included in Winter solutions below |
| | | Site thermal replacement plants to reduce impact | Not quantified | | | Not needed if winter problem is solved |
| Summer: Upper/Mid Columbia Load Service | Thermal overloads | New Schultz-Hanford transmission line | 50 to 75 | 0.17 | 3.6 to 5.2 | 3.6 to 5.2 |
| Summer: Tri-Cities Service | Voltage support to the Tri-Cities | Ice Harbor generators converted to synchronous condensers | 2 to 6 | 0.2 | 0.4 to 0.6 | 0.4 to 0.6 |
| | Load service impacted | Local line transmission improvements | 10 to 20 | 0 | 0.7 to 1.4 | 0.7 to 1.4 |
| Summer: Montana transfer to Northwest | Transfer limit is reduced by 500 MW | New Bell-Ashe transmission line | 100 to 150 | 0.38 | 7.2 to 10.5 | 7.2 to 10.5 |
| Summer: Canada Transfer to Northwest | Increased congestion on I-5 transmission corridor | No solution offered | Not quantified | | | |
| Winter: Meeting extreme winter loads | Import capability is reduced and results in inability to meet extreme loads | Site <1000 MW of replacement generation | Not needed because assumed built for power system needs | | | |
| | | And - Big Eddy - Ostander | 70 to 120 | 0.2 | 4.9 to 8.3 | 4.9 to 8.3 |
| Winter: Tri-Cities Load Service | Load Service Limitations | Local transmission improvements McNary - Franklin | 15 to 20 | 0.1 | 1.1 to 1.5 | 1.1 to 1.5 |
| **Totals 1/** | | | **$327 to $521** | | | **$23.5 to $36.5** |

1/ Includes only costs for selected solutions

**Table 22.**
**Transmission Impacts with John Day at Nat. River & 4 Snake Dams Breached Power Alternatives JD6 & JD7**
**Annual Values Based on 6.875%**

| Timing/Location of Impacts | Impact Description | Possible Solutions | Estimated Construction Costs ($millions) | Incremental O&M Costs ($millions) | Total Annual Costs ($millions) | Selected Solution Aver Annual Costs ($millions) |
|---|---|---|---|---|---|---|
| Summer: NW to California | Transfer limit is reduced (a cutplane problem) | Limit COI/PDCI transfer capability from 7200 MW to 5400 MW | Not quantified | | | |
| | | Upgrade the COI/PDCI | 65 to 85 | 0.3 | 5.1 to 5.9 | Included in Winter solutions below |
| | | Site thermal replacement plants to reduce impact | Not quantified | | | Not needed if winter problem is solved |
| Summer: Upper/Mid Columbia Load Service | Thermal overloads | New Schultz-Hanford transmission line | 50 to 75 | 0.17 | 3.6 to 5.2 | 3.6 to 5.2 |
| Summer: Tri-Cities Service | Voltage support to the Tri-Cities | Ice Harbor generators converted to synchronous condensers | 2 to 6 | 0.2 | 0.4 to 0.6 | 0.4 to 0.6 |
| | Load service impacted | Local line transmission improvements | 10 to 20 | 0 | 0.7 to 1.4 | 0.7 to 1.4 |
| Summer: Montana transfer to Northwest | Transfer limit is reduced by 500 MW | New Bell-Ashe transmission line | 100 to 150 | 0.38 | 7.2 to 10.5 | 7.2 to 10.5 |
| Summer: Canada Transfer to Northwest | Increased congestion on I-5 transmission corridor | No solution offered | Not quantified | | | |
| Winter: Meeting extreme winter loads | Import capability is reduced and results in inability to meet extreme loads | Site 1000 MW of replacement generation | Not needed because assumed built for power system needs | | | |
| | | And New transmission lines - Capt Jack - Meridian | 80 to 130 | 0.2 | 5.6 to 9.0 | 5.6 to 9.0 |
| | | and - Big Eddy - Ostander | 70 to 120 | 0.2 | 4.9 to 8.3 | 4.9 to 8.3 |
| Winter: Tri-Cities Load Service | Load Service Limitations | Local transmission improvements McNary - Franklin | 15 to 20 | 0.1 | 1.1 to 1.5 | 1.1 to 1.5 |
| **Totals 1/** | | | **$327 to $521** | | | **$23.5 to $36.5** |

1/ Includes only costs for selected solutions

| Table 23. Summary of Transmission System Impacts Average Annual Costs at 6.875%, ($ 1998 Million) | | | |
|---|---|---|---|
| **Study Alternative** | **Power Scenario** | **Low Side Transmission Costs** | **High Side Transmission Costs** |
| **Without Project Condition** | JD 1 | -- | -- |
| **Alternatives 1&2** | JD 2 | 1.6 | 21.9 |
| | JD 3 | 23.5 | 36.5 |
| | JD 4 | 23.5 | 36.5 |
| **Alternatives 3&4** | JD 5 | 21.9 | 28.1 |
| | JD 6 | 23.5 | 36.5 |
| | JD 7 | 23.5 | 36.5 |

## 5.9. Ancillary Services Effects

This section discusses the ancillary services and the estimated economic values of these services provided by John Day Dam. These ancillary services are in addition to the energy, capacity, and transmission support benefits discussed elsewhere in this report. With the open access transmission ruling of the FERC, power suppliers are now charging for many of the ancillary services that in the past were generally provided without charge by the entities owning the transmission facilities. Starting in 1998 BPA has begun to sell these ancillary services. Since these services are a necessary element of a safe and reliable power system, the loss of these services represents economic costs that must be accounted for in this analysis.

The John Day hydropower plant is used for Automatic Generation Control (AGC). Small, but very frequent changes in generation are necessary to perform this function. Hydroelectric projects, with stored water as their fuel, are extremely flexible and very useful for this purpose. If John Day dam were removed, its contribution to this system would have to be spread over the remaining projects or replaced from other sources. To value the AGC the BPA staff that deals with market sales of ancillary services were consulted. The economic value of AGC that will be lost with the removal of the John Day dam was based on the percent of time that AGC is utilized, the MW magnitude, and the market value. Table 24 shows the computation of lost value for AGC with John Day at natural river level and the spillway level. John Day could not continue to provide AGC at the spillway level because of restrictions on the changes in generation. At the spillway level the generation flexibility of the project would be severely limited. The control of the amount of generation at the spillway level will be provided by operation of the spillway gates. This would provide inadequate flexibility to the point that AGC could not be provided to the system. BPA relies on AGC from John Day about 100 percent of the time at a level of about 100 MW. The market value of the AGC on a monthly basis was used to compute the monthly losses. The average annual value was estimated to be $ 7.7 million.

John Day dam is also used to provide part of the required reserves for the Federal power system. The WSCC has established reserve requirements for all utilities. These contingency reserves are expected to be “on-call” in the event of emergency loss of generating resources in the system. Utilities are required to have both operating and spinning reserves. The spinning reserve units must be synchronized with the power system and provide immediate response, while the operating reserves must be available within 10 minutes. BPA estimates that the John Day plant is used for reserves throughout the year during the heavy load hours. BPA relies on about 300 MW of reserves from this plant. The market values of these reserve services vary throughout the year. In the high demand winter months it was assumed that BPA would have to purchase power from the market at a value of $31/MW-month to create reserve margin on the system. During the rest of the year it was assumed BPA would sell this reserve at the average monthly market prices. The annual net economic cost associated with the loss of these reserves with John Day at the natural river level or the spillway level was estimated to be $ 15.3 million (see Table 25).

To compute the total ancillary service losses of all the power scenarios, the results of the Snake River study for the scenarios with dam breaching were added to the AGC and reserve values are computed in Table 26.

**Table 24.**
**Automatic Generation Control Losses**
**John Day Dam at Natural River & Spillway**

| Month | Hours Per Month | MW Provided | Percent of Time | Value (1998 Real $) | Monthly Value |
|---|---|---|---|---|---|
| Jan | 744 | 100 | 100% | 9.50 | 706,800 |
| Feb | 672 | 100 | 100% | 9.50 | 638,400 |
| Mar | 744 | 100 | 100% | 8.50 | 632,400 |
| Apr | 720 | 100 | 100% | 5.00 | 360,000 |
| May | 744 | 100 | 100% | 5.00 | 372,000 |
| Jun | 720 | 100 | 100% | 6.50 | 468,000 |
| Jul | 744 | 100 | 100% | 9.50 | 706,800 |
| Aug | 744 | 100 | 100% | 16.50 | 1,227,600 |
| Sep | 720 | 100 | 100% | 11.50 | 828,000 |
| Oct | 744 | 100 | 100% | 6.50 | 483,600 |
| Nov | 720 | 100 | 100% | 8.50 | 612,000 |
| Dec | 744 | 100 | 100% | 9.50 | 706,800 |
| Annual | 8760 | 100 | 100% | | $7,742,000 |

| Table 25.<br>Lost Annual Reserve Values<br>John Day Dam At Natural River & Spillway | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Month** | **Heavy Load Hours** | **MW Provided** | **Purchase % of time** | **Market Sale % of time** | **Purchase Cost (1998 Real $)** | **Market Value (1998 Real $)** | **Monthly Value** |
| **Jan** | 496 | 300 | 25% | 75% | 31.00 | 8.00 | 2,046,001 |
| **Feb** | 448 | 300 | 25% | 75% | 31.00 | 8.00 | 1,848,001 |
| **Mar** | 496 | 300 | 0% | 100% | 31.00 | 7.00 | 1,041,601 |
| **Apr** | 480 | 300 | 0% | 100% | 31.00 | 3.50 | 504,000 |
| **May** | 496 | 300 | 0% | 100% | 31.00 | 3.50 | 520,800 |
| **Jun** | 480 | 300 | 0% | 100% | 31.00 | 5.00 | 720,000 |
| **Jul** | 496 | 300 | 0% | 100% | 31.00 | 8.00 | 1,190,401 |
| **Aug** | 496 | 300 | 0% | 100% | 31.00 | 15.00 | 2,232,001 |
| **Sep** | 480 | 300 | 0% | 100% | 31.00 | 10.00 | 1,440,001 |
| **Oct** | 496 | 300 | 0% | 100% | 31.00 | 5.00 | 744,000 |
| **Nov** | 480 | 300 | 0% | 100% | 31.00 | 7.00 | 1,008,001 |
| **Dec** | 496 | 300 | 25% | 75% | 31.00 | 8.00 | 2,046,001 |
| | | | | | | | |
| **Annual (Rounded)** | | | | | | | **$ 15,340,800** |

| Table 26.<br>John Day Ancillary Service Losses<br>Annual Economic Effects (Millions '98 Dollars)<br>Differences From Without Project Condition | | | | | | |
|---|---|---|---|---|---|---|
| **Study Alternative** | **Alternatives 1&2** | | | **Alternatives 3&4** | | |
| **Power Scenario** | JD 2 | JD 3 | JD 4 | JD 5 | JD 6 | JD 7 |
| John Day AGC | 7.7 | 7.7 | 7.7 | 7.7 | 7.7 | 7.7 |
| John Day Reserve | 15.3 | 15.3 | 15.3 | 15.3 | 15.3 | 15.3 |
| Snake River Ancillary | 0.0 | 8.0 | 8.0 | 0.0 | 8.0 | 8.0 |
| **Total Ancillary Losses** | **23.0** | **31.0** | **31.0** | **23.0** | **31.0** | **31.0** |

## 5.10. Summary of Hydropower Net Economic Effects

This section combines the net economic effects as defined by the medium projection conditions. These represent the most likely point estimates of economic effects and are the most comparable to economic impacts identified elsewhere in the analysis.

The total net economic effects are shown in Table 27 for the medium economic forecast condition. This table combines the system costs computed with the two study approaches of system production costs (Table 18) and market price estimates (Table 20) with the transmission reliability effects presented in Table 23 and the ancillary services in Table 26.

As shown in this table the range of annual net economic costs for hydropower effects of alternatives 1 & 2 range from about $125.8 million to $161.6 million.  The range of annual net economic costs for hydropower effects of alternatives 3 & 4 range from about $247.8

million to $281.9 million. For comparison purposes a point estimate of the most likely economic cost for hydropower was needed to compare to and combine with other economic impacts. The study team decided that the average between the minimum and maximum would represent a reasonable point estimate for this study. The point estimate of net economic costs is provided in the last row of Table 27.

**Table 27.**
**Hydropower Analysis: Summary of Annual Net Economic Effects**
**Differences From the Without Project Condition**
**Medium Forecast Projections, 1998 $ Million, 6-7/8% Discount**

| Category: | Alternatives 1&2 | | | Alternatives 3&4 | | |
|---|---|---|---|---|---|---|
| | JD 2 | JD 3 | JD 4 | JD 5 | JD 6 | JD 7 |
| **System Costs 1/:** | | | | | | |
| BPA Production Costs | 118.0 | 379.0 | 374.6 | 233.1 | 499.5 | 463.4 |
| PROSYM Production Costs | | | | 211.0 | | |
| **Transmission Reliability Costs** | | | | | | |
| Low | 1.6 | 23.5 | 23.5 | 21.9 | 23.5 | 23.5 |
| High | 21.9 | 36.5 | 36.5 | 28.1 | 36.5 | 36.5 |
| **Ancillary Services Costs** | 23.0 | 31.0 | 31.0 | 23.0 | 31.0 | 31.0 |
| **SUMMARY:** | | | | | | |
| **Minimum Cost** | 125.8 | 371.3 | 366.0 | 247.8 | 476.9 | 444.0 |
| **Maximum Cost** | 162.9 | 446.5 | 442.1 | 284.2 | 567.0 | 530.9 |
| **Point Estimate 2/** | **144** | **409** | **404** | **266** | **522** | **487** |

1/ Results are presented for the two different study approaches.
2/ For comparison purposes a point estimate was computed as the mid - point of the range of estimated net economic costs

# Section 6. AIR POLLUTANT EMISSIONS FROM REDUCED HYDROPOWER

This air pollutant portion of the power analysis is intended to identify, on a cursory level, increases or decreases in different types of emissions resulting from changes in the amount of hydropower production from the John Day Dam. This is not intended to be a full examination of the air quality aspects associated with other aspects of the drawdown such as reduced barging and construction-related air pollution.

The Clean Air Act and concerns over greenhouse gasses are geared towards limiting emissions of pollutants into the air. One obvious advantage of hydropower generation is that it emits no pollutants into the air. With the reduction of hydropower production, alternative generation sources will be used to replace lost electricity. These alternatives will be thermal based and fueled by fossil fuels, and consequently will release increased levels of several harmful emissions.

The PROSYM power system model, which was used in the hydropower economic analysis, provided a convenient tool for identifying potential air pollutant emissions from thermal generating plants in the WSCC region. USACE utilized the model under contract with HESI to evaluate the John Day Dam natural river drawdown alternatives and this air emission analysis. The PROSYM model has an extensive database, which includes operating characteristics of all WSCC power plants, current fuel prices, plant efficiencies, and inter-regional marketing conditions. The model dispatches thermal and hydropower generating resources on an hourly basis to meet energy demand. For more information on this model the reader should refer to Section 1.1.6 of this report, or Section 4.2.2 of the Lower Snake River Juvenile Salmon Migration Feasibility Study report, "*Technical Report On Hydropower Costs and Benefits, 31 March 1999.*"

The approach used to estimate increased air emissions with the drawdown of John Day Dam to natural river level, was as follows. The PROSYM model meets hourly loads in the most economic manner possible and identifies which power plants will generate at which time to serve power demands. The amount of hours the thermal power plants operate changes when the amount of PNW hydropower changes. Emission factors for each of the thermal plants were multiplied by the number of hours each plant operated to estimate pollutant releases. The emission factors were obtained from actual emissions reported to EPA in annual power plant emission reports. The model is limited to emission estimates for carbon dioxide ($CO_2$), nitrogen oxide (NOx), and sulfur dioxide ($SO_2$). The change in air emissions were then estimated by comparing the amount of tons of air emissions from power plants in the Pacific Northwest (PNW) in the without project condition (power alternative JD1) and the natural river drawdown of John Dam (power alternative JD5).

This analysis was limited to only the natural river drawdown plans of alternatives 3 and 4, and one year in the future (2020). The results could be considered a reasonable estimate of the increased amount of annual air emissions that would occur within the PNW. The analysis is based on the assumption that the lost energy and capacity from John Day Dam will be replaced with increased generation from existing power plants and with construction of 960 MW of new combined cycle combustion turbines (CC) fueled by natural gas. It must be emphasized that the results of the analysis are hypothetical and are based on the least cost approach. The real world response to increasing power demand and reduced hydropower production may be different. Other less polluting alternatives could be implemented, such as conservation, but these would be more costly ways to replace the lost hydropower generation.

The siting of the replacement CC plants may be a critical factor. The modeling done for the air emissions analysis did not consider air-shed limitations. It is assumed that new power plants added to the regions will meet all applicable Federal, state, and local air quality regulations.

Table 28 presents the results of the air emission analysis. The left of the table provides the total estimation air emissions for the three pollutants that were estimated to occur in year 2020 in the without project condition. The last three columns of the table provide the estimated increase in emissions with the removal of the John Day generation and the building of 960 MW of replacement CC plants.

As can be seen from Table 28 the percentage increase in emissions of the pollutants of $SO_2$ and NOx is well below one percent. The increase in $CO_2$ in the PNW is estimated to be about four percent due to the loss of hydropower generation from John Day Dam.

| Table 28. Air Emission Increases Due To Lost Hydropower Emission Totals for the Pacific Northwest (000 tons) Year 2020 Estimates With Alternatives 3 & 4 | | | | | | |
|---|---|---|---|---|---|---|
| | Without Project Condition | | | Increases From Without Project Condition With Alternatives 3 & 4 | | |
| **Month** | **SO2 (000 tons)** | **NOx (000 tons)** | **CO2 (000 tons)** | **SO2 (000 tons)** | **NOx (000 tons)** | **CO2 (000 tons)** |
| **Jan** | 11.5 | 6.7 | 6,209.2 | (0.005) | 0.004 | 171.8 |
| **Feb** | 10.4 | 5.9 | 5,057.5 | (0.002) | 0.020 | 174.9 |
| **Mar** | 10.6 | 6.1 | 5,282.3 | 0.001 | 0.033 | 221.5 |
| **Apr** | 7.9 | 4.6 | 4,060.4 | 0.006 | 0.065 | 280.8 |
| **May** | 6.5 | 3.9 | 3,635.3 | 0.002 | 0.046 | 226.1 |
| **Jun** | 9.3 | 5.3 | 4,133.1 | 0.006 | 0.051 | 206.9 |
| **Jul** | 9.4 | 5.5 | 4,974.0 | 0.001 | 0.041 | 231.6 |
| **Aug** | 8.7 | 5.3 | 5,268.7 | (0.002) | 0.024 | 223.8 |
| **Sep** | 11.1 | 6.4 | 5,938.0 | (0.002) | 0.019 | 176.2 |
| **Oct** | 10.6 | 6.2 | 5,798.1 | 0.006 | 0.052 | 196.7 |
| **Nov** | 11.1 | 6.5 | 5,966.4 | 0.001 | 0.034 | 194.0 |
| **Dec** | 11.5 | 6.7 | 6,431.9 | (0.002) | 0.048 | 260.1 |
| **Annual** | 118.8 | 69.1 | 62,754.9 | 0.009 | 0.437 | 2,564.3 |
| | | **Percentage Increase =** | | 0.01% | 0.63% | 4.09% |

* Based on PROSYM simulations for year 2020 with 960 MW of replacement generation from natural gas-fired plants. A negative number implies a reduction in emissions in that month.

# Section 7. Hydroregulation.

## 7.1. Introduction

### 7.1.1. General.

Hydroregulation studies are used to simulate the multi-purpose characteristics of a river basin system of water control projects under varying conditions of loads and flows over an extended period of time. Most recently, the hydroregulation studies have been used to determine impacts to the system as non-power requirements are imposed. USACE of Engineers uses a Fortran program called HYSSR, which stands for Hydro System Seasonal Regulation, to run the hydroregulations. HYSSR was developed to model any river basin, but over the years, the Corps of Engineers, Northwestern Division has developed the program to simulate the reservoir and dam system in the Pacific Northwest, which include dams in Oregon, Washington, Idaho, Montana and the Canadian portion of the Columbia River Basin.

### 7.1.2. Purpose.

The main purpose of the Hydroregulation studies for John Day Drawdown Phase I Study is to provide data regarding power generation values to be used in the economic evaluation of seven John Day Drawdown alternatives. The Hydroregulations also provide data regarding regulated flow, spill volumes and end of month elevations that can be used to aid in determining the ability of the system to meet the Biological Opinion (BiOp) fisheries objectives to assist in the biological evaluation of alternatives.

### 7.1.3. Scope.

The scope of work for the Hydroregulation portion of the study involved preparing specifications for each of the seven alternatives, coordinating the specifications with fisheries agencies and other federal agencies, modeling the alternatives by utilizing the Corps of Engineer's Hydro System Seasonal Regulation (HYSSR) model, and preparing a report of the results of the model runs with an emphasis on impacts to system generation.

### 7.1.4. Related Study.

A related study underway is the Lower Snake River Juvenile Mitigation Feasibility Study being prepared by the Walla Walla District of the Corps of Engineers. There are four alternatives from this study that have the same scenarios as four alternatives in the John Day Drawdown Study, but they were required to be modified due to new data and new fisheries objectives. The new data consists of updated loads, rule curves, and flood control. The new fisheries objectives includes adding Priest Rapids steelhead objectives from the 1998 Steelhead Supplemental BiOP, revised sturgeon objectives from USACE' 1999 Bull Trout and Sturgeon Biological Assessment, new fish spill requirements, revised Lower Granite objectives, bull trout objectives, and new reservoir draft limits.

### 7.1.5. Coordination.

Draft specifications for the hydroregulations of each alternative were sent to the following agencies for review: the National Marine Fisheries Service (NMFS), the Columbia River Intertribal Fish Commission, the U.S. Fish and Wildlife Service, Northwest Power Planning Council (NWPPC), Bonneville Power Administration (BPA), the Bureau of Reclamation, Oregon Department of Fish and Wildlife, Umatilla Electric Cooperative, and the Plan for Analysis and Testing Hypothesis (PATH) Group. Agencies were invited to a meeting held on February 16$^{th}$, 1999 to discuss review comments on the specifications. Review comments were received from the NMFS, BPA and NWPPC. Those comments were incorporated into the final specifications where applicable.

## 7.2. Description of Hydroregulation Study Alternatives.

The alternatives consist of a Base Case, Alternative JD1, and 6 drawdown alternatives, JD2 through JD7. The Base Case represents existing conditions and the project operating constraints that have been agreed to for use in planning studies. Six drawdown alternatives consist of combinations of John Day operating 5 ft to 10 feet above spillway crest or operating at natural river, the Lower Snake Projects operating at minimum operating pool (MOP) or at natural river, and flow augmentation or no flow augmentation for the Lower Snake and /or the Columbia River. It should be noted that there were four alternatives considered in the John Day Drawdown Phase I Study, Structural Alternatives Report. The four alternatives are: John Day Drawdown to Spillway Crest with and without flood control, and John Day Drawdown to Natural River with and without flood control. The hydroregulations reflect conditions with or without flood control. For all hydroregulation study alternatives, it is assumed that the John Day Project would be operated for flood control by raising the pool and storing water until the risk of flooding downstream has subsided. This would only last for a few days to a week, and therefore is not considered to have an effect in the hydroregulation's monthly model. It was deemed necessary to study the hydro system with and without the Lower Snake projects operated at natural river level and at MOP because these are options that are being considered through other studies. Flow augmentation on the Snake rivers was removed in 2 of the options and on the Columbia in one option to determine the magnitude of the gain in energy capability of the system without flow augmentation. Table 29 shows the alternative identification number and its attributes.

## 7.3. Specifications.

Specifications were prepared for each alternative that identify the operation for each project. The projects will operate to meet power and non-power requirements. Non-power requirements consist of flood control and fisheries objectives. The fisheries objectives are based on the NMFS 1995 Biological Opinion (BiOp), the 1998 Steelhead Supplemental BiOp, and the forth coming Corps of Engineers 1999 Bull Trout and Sturgeon Biological Assessment (BA). The non-power requirements consist of flow objectives and draft limits for anadromous fish and resident fish. The detailed specification for the Base Case, Alternative JD1 is provided in Section 8.0. Detailed specifications for each of the other alternatives will be available upon request.

## 7.4. The HYSSR Model.

Elements of a hydroregulation study consist of the main HYSSR program, the input files, and the output files.

### 7.4.1. Main HYSSR Program.

The HYSSR model is a personal computer based Fortran program that models approximately 80 dams and reservoirs in a coordinated river system in the Pacific Northwest. The model is used to analyze alternatives by optimizing the operation of the 80 projects to meet various water resource needs. The program simulates the power generating and flood control characteristics of a river basin system of dams and reservoirs under varying conditions of loads, natural stream flows, and non-power constraints. The model can be specified to cover a period of up to 60 years. The model may be run in continuous mode or refill mode. In the continuous mode, the project initial elevations start at preset elevations and runs sequentially from month to month with the beginning of the next year starting at the end of the previous year. In the refill mode, the model runs the same way except the next year starting elevation is reset to the preset elevations.

### 7.4.2. Input Data.

Input data consist of three levels. The first level is the basic data that does not change over very long periods of time, such as project configurations and characteristics. Project configurations identify the relation of one project to another (which projects are upstream and downstream of each other). Project characteristics is data pertinent to each project, such as plant generating capacity, turbine efficiency, storage/elevation relationships, and tailwater vs. discharge relationships. The second level of input data consists of data that will not change during the course of the studies. Natural stream flows and project forebay flood control elevations are this type of data. The third level of input consist of data that changes with each alternative. This data consist of forebay draft limits (the lowest elevation the project forebay is to operate to), target forebay elevations, flow objectives, and special operations.

### 7.4.3. Output Data.

Model output consist of tables of data for each project, for each year of the study (up to 60 years) and for each period. Each period consists of a month, except for April and August for which there are 2 periods in each of these months. Examples of project output data consists of regulated flow, end of month elevations, regulated power generation, and spill. Other useful data output consists of system data. System data provides information such as system generation, surplus energy, plant capability, and firm hydro load. The system tables sum data from each project to arrive at total values for the system. Projects to be included in the system tables may be specified in the input files.

**Table 29.**
**John Day Phase I - Alternatives for HYSSR Analysis**

| | John Day Level | | | Snake R. Dams | | JDA Flood Control | | JDA Power | | U. Snake Flow Augmentation | 1995 BiOp Flow Augmentation | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Alternative | Exis-ting | Spillway | Nat. River | Nat. River | MOP | None (1) | 537 kaf | None | Existing | kaf | Columbia | Snake |
| **Base Condition** | | | | | | | | | | | | |
| JD 1 | X | | | | X | | X | | X | 427 | X | X |
| **John Day at Spillway** | | | | | | | | | | | | |
| JD 2 | | X | | | X | | X | | X | 427 | X | X |
| JD 3 | | X | | X | | | X | | X | 427 | X | X |
| JD 4 | | X | | X | | | X | | X | 0 | X | |
| **John Day at Natural River** | | | | | | | | | | | | |
| JD 5 | | | X | | X | | X | X | | 427 | X | X |
| JD 6 | | | X | X | | | X | X | | 427 | X | X |
| JD 7 | | | X | X | | | X | X | | 0 | | |
| | | | | | | | | | | | | |

Note: (1) See paragraph 1.6.

## 7.5. HYSSR Modeling for the John Day Drawdown Alternatives.

The HYSSR model was run in continuous mode for a period of 60 years. The study began on 1 August, 1928 and ended on 31 July, 1988. The model was run for each of the 7 alternatives. An initial model run was made for each alternative and then adjusted to best meet the fisheries objectives without exceeding project operating requirements, such as minimum and maximum flows, and draft limits. Input files for each alternative are built from a previous set of input files starting with the Base Case. The following paragraphs describe the input data used for each alternative.

### 7.5.1. Base Case JD1.

The Base Case, JD1, consists of the most current project operations with some minor adjustments as agreed to during the coordination of the specifications. Much of the data is as submitted to the Northwest Power Pool (NWPP) for Pacific Northwest Coordination Agreement (PNCA) planning for operating year (OY) 1998-1999, except as noted. For additional details, see Section 8.0.

- The base case alternative used load and rule curves as developed by the NWPP for the OY 98-99.
- John Day is operated Pool El. 262.5 during the fish passage season. The fish passage season is the second half of April through August. The rest of the year it is operated at Pool El. 265.0.
- The Lower Snake River projects were on MOP operation.
- Brownlee is on a fixed operation. The Upper Snake River projects were operated to provide flow augmentation of 427 KAF in the summer for the Lower Snake. The flow augmentation data used was provided from the Bureau of Reclamation to the Corps of Engineers in June of 1998.
- The Canadian projects are on a fixed operation using the Arrow Total Method from the 1998 AOP.
- Projects on the Lower Columbia, and the Lower Snake Rivers spill for juvenile fish passage in accordance with the 1998 PNCA data submittal. Projects on the mid-Columbia spill up to the spill cap that produces 110 percent Total Dissolved Gas (TDG).
- Grand Coulee and Hungry Horse augments for steelhead at Priest Rapids Dam according to the 1998 Supplemental BiOP. The objectives are to pass 135,000 cfs from April 10 through June 30. For monthly modeling purposes, 90,000 cfs was used for the month of April.
- Grand Coulee and Hungry Horse augments for McNary according to the 1995 BiOP. Libby augments for McNary and Bonners Ferry flow objectives in July and August by releasing the volume of water above El. 2439 at the end of June on a straightline basis to Pool El. 2439 feet at the end of August to avoid double peaking for protection of bull trout. The July and August Libby augmentation is based on the 1999 Bull Trout and Sturgeon BA.

- Dworshak augments for Lower Granite flow objectives. The flow objectives used were based on the flow objectives as used in the Lower Snake River Juvenile Mitigation Feasibility Study, Alternative A6a currently being prepared by the Walla Walla District, Corps of Engineers. These flow objectives were used instead of those in the 1995 BiOp at the request of the National Marine Fisheries Service (NMFS). The purpose of these flow objectives is to help Dworshak refill in low water years at the end of June to help summer flow augmentation.
- Libby augments for sturgeon flow objectives in May and June according to the forth coming Corps of Engineers 1999 Bull Trout and Sturgeon (BA).
- Grand Coulee will operate to meet Vernita Bar objectives in December through May and may draft to the storage lower bounds of Pool El. 1208 feet for Vernita Bar. The objectives are the higher of 68 percent of Wanapum's October or November regulated flow rounded to the nearest 5,000 cfs, but no higher than 70,000 cfs, and not less than 50,000 cfs.
- Grand Coulee may not go below resident fish limits of pool El. 1260, 1250, and 1240 ft in January through March, respectively (these draft limits may be exceeded to meet Vernita Bar objectives).
- Variable Draft Limits (VDL's) are used at Grand Coulee and Hungry Horse in January through March to provide 85 percent and 75 percent confidence, respectively, of reaching flood control on April 10$^{th}$, according to the requirements set by the Bureau of Reclamation. The purpose of having the projects on flood control by April 10$^{th}$ is to aid in ensuring that the maximum amount of water is available for flow augmentation for the McNary and Priest Rapids flow objectives. The final draft limits for January through March will be the higher of the resident fish draft limits and the VDL's.
- Flood Control elevations developed by USACE were as submitted for the PNCA for operating year 1999-2000. The operating year starts August 1$^{st}$ and ends July 31$^{st}$. Flood control space was shifted from Dworshak and Brownlee to Grand Coulee to help ensure these projects will store as much water as possible for fish flow augmentation in the spring and summer.

### 7.5.2. Alternative JD2.

This alternative contains the same input data as Alternative JD1 except that John Day pool is operated at 5 feet to 10 feet above the spillway crest. During the fish passage season, 20 April through 31 August, John Day is operated at El. 215 ft and the remainder of the time the pool is operated at El. 220 feet The McNary tailwater curve was adjusted from Alternative JD1 to reflect the lowered John Day pool. The generation at McNary will increase due to the removal of the encroaching pool of John Day Dam. The John Day project is capable of generating power, but will result in a lesser amount than when operated at full pool.

### 7.5.3. Alternative JD3.

This alternative contains the same input data as Alternative JD2 but the Lower Snake projects, Lower Granite, Little Goose, Lower Monumental, and Ice Harbor are operated at natural river elevations of El. 638, El. 540 ft, El. 440 ft, and El. 340 feet instead of at MOP. There will be no power generation or spill at the Lower Snake projects.

### 7.5.4. Alternative JD4.

This alternative contains the same input data as Alternative JD3 except that there is no flow augmentation from the Upper Snake projects and Dworshak. The flow objectives for Lower Granite are removed, therefore Dworshak does not augment for Lower Granite. Flood control was not shifted from Dworshak and Brownlee to Grand Coulee. Dworshak will operate to meet the load within the flood control constraints. Dworshak also has a summer recreation draft limit of El. 1595 feet

### 7.5.5. Alternative JD5.

This alternative contains the same input data as Alternative JD2, but John Day is operated year round at natural river elevation, or pool El. 165 feet There is no spill or power generation at John Day.

### 7.5.6. Alternative JD6.

This alternative contains the same input data as Alternative JD5, but Lower Snake projects are at natural river elevations. There will be no spill or power generation at the Lower Snake projects.

### 7.5.7. Alternative JD7.

This alternative contains the same input data as Alternative JD6, but there is no flow augmentation on the Columbia or Upper Snake Rivers. This alternative would represent the system requirements as it operated before the BiOp requirements and water budget. The following are the changes to the input file:

- Loads and rule curves from OY 82, except the Canadian projects will continue to be on the OY 99 fixed operation.
- Flood Control is non-shifted.
- McNary flow objectives are removed.
- Lower Granite flow objectives are removed.
- Priest Rapids flow objectives are removed.
- Variable Draft Limits for Grand Coulee and Hungry Horse are removed.
- Libby no longer auguments for McNary in July through August by trout straight line operation. Libby auguments for sturgeon May through July. In August, Libby will operate to meet the load subject to the recreation draft limits of Pool El. 2454 feet
- Grand Coulee will operate to meet the load year around subject to resident fish draft limits in January through March and September through October, the pumping draft limit in May, and the recreation draft limit in June through August. The Vernita Bar requirements remain the same. A ferry draft limit of 1220 ft is imposed year around,

except the project may draft to El. 1208 ft to meet Vernita Bar requirements in December through May.

- Hungry Horse will operate to meet the load year around.
- Brownlee is on a fixed operation and meets flood control.
- Dworshak will operate to meet load year around subject to the recreation draft limit of Pool El. 1595 in June through August. The maximum flow for October through November is the natural streamflow plus 1300 cfs for steelhead.
- The non-federal projects are on a fixed operation which is the same operation resulting from the base case JD1 alternative.

## 7.6. Comparison of Results.

The following paragraphs provide a summary of the results for comparison between the Base Case JD1 and Alternatives JD2 through JD7. Comparison tables are also provided.

### 7.6.1. Alternative JD1 vs. JD2.

The main difference between JD1 and JD2 is that John Day is operated near spillway crest instead of at Pool El. 262.5 during the fish passage season and Pool El. 265.0 the rest of the year. The John Day project lost 607 aMW due to this operation. The system lost 557 aMW. This means that the system recovered 50 aMW by drafting other projects as needed to meet the load. Libby drafted .8 ft more than in JD1 in September through October, and less than 0.3 ft more in April through July. Hungry Horse drafted from 0.5 ft to 3.1 feet more throughout the year. Grand Coulee drafted .2 ft to 2.4 feet more in October through March, and Dworshak drafted 0.9 ft to 2.1 feet more from September through May.

### 7.6.2. Alternative JD1 vs. JD3.

The main difference between JD1 and JD3 is that John Day is operated near spillway crest instead of at Pool El. 262.5 during the fish passage season and Pool El. 265.0 the rest of the year, and the four Lower Snake projects are operated at natural river elevation. John Day project lost 606 aMW, and the Lower Snake river projects lost 1200 MW for a total of 1806 aMW. The system lost 1763 aMW. This means that the system recovered 44 aMW by drafting other projects as needed to meet the load. Libby drafted 3.4 ft to 3.7 feet more than in JD1 in September through November and 0.4 to 0.5 feet more in March through April. Hungry Horse drafted 4.6 ft to 15.5 feet more throughout the year with the greatest draft of about 12 ft to 15.8 feet more in January through April. Grand Coulee drafted September through May from 0.4 to 6.3 feet more in September through May with the greatest draft in December through February of about 5 ft to 6 feet more. Dworshak drafted September through June from 0.9 ft to 12.4 feet more with the greatest draft from September through April 15 of 7.0 ft to 12.4 feet.

### 7.6.3. Alternative JD1 vs. JD4.

The main difference between JD1 and JD4 is that John Day is operated near spillway crest instead of at Pool El. 262.5 during the fish passage season and Pool El. 265.0 the rest of the year, the four Lower Snake projects are operated at natural river elevation, and there is no flow augmentation from the Upper Snake. John Day project lost 605 aMW, the Lower Snake river projects lost 1200 aMW for a total of 1805 aMW. The system lost 1741 aMW. This means that the system recovered 64 aMW by drafting other projects as needed to meet the load. Libby, Hungry Horse, and Grand Coulee drafted similarly as in JD3. Since there was no flow augmentation from Dworshak for Lower Granite flow objectives, Dworshak operated in proportional draft mode to meet the load throughout the year. Dworshak drafted 7.8 feet to 42 feet more than in JD1 in November through March and held back the pool from 3.6 to 18.9 feet more in July through October.

### 7.6.4. Alternative JD1 vs. JD5.

The main difference between JD1 and JD5 is that John Day is operated at natural river level. John Day lost 1146 aMW while the system lost 1087 aMW. This means that the system recovered 59 aMW by drafting other projects as needed to meet the load. Libby drafted about 1.7 feet more than in JD1 in September through November. Hungry Horse drafted 2.3 feet to 8.8 feet more throughout the year with the maximum draft of 6.4 to 8.8 feet more occurring in January through April. Grand Coulee drafted 0.6 to 1.5 feet more in October through March. Dworshak drafted 0.5 to 6.4 feet more in September through June.

### 7.6.5. Alternative JD1 vs. JD6.

The main difference between JD1 and JD6 is that John Day and the 4 Lower Snake Projects are operated at natural river levels. John Day lost 1146 aMW and the four Lower Snake River projects lost 1200 aMW for a total of 2346 aMW lost. The system lost 2321 aMW. This means that the system recovered 25 aMW by drafting other projects as needed to meet the load. Libby drafted an additional 4.3 to 5.2 feet in September through November and 0.7 ft in March through April. Hungry Horse drafted an additional 6.5 to 22.8 feet throughout the year, with the greatest occurring in January through April of 17.1 to 22.8 feet Grand Coulee drafted 0.5 feet to 9.4 feet more than JD1 in September through May. Dworshak drafted 0.7 feet to 21.7 feet more September through June with the greatest in September through March of 10 feet to 21.7 feet.

### 7.6.6. Alternative JD1 vs. JD7.

The main difference between JD1 and JD7 is that John Day and the four Lower Snake Projects are operated at natural river levels, and there is no flow augmentation for the Columbia and Lower Snake Rivers. John Day lost 1146 aMW and the Lower Snake River Projects lost 1200 aMW for a total of 2346 aMW. The System lost 2224 aMW. This means the system recovered 122 aMW by drafting other projects to meet the load. In general, Libby held back and additional 8.7 to 20.8 feet of pool from JD1 in July through November, while drafting about .8 feet more in March through April. Hungry Horse Held back the pool from 1.2 ft to 4.1 feet more in July through September while drafting in October through June from 1.6 ft to 23.6 feet more. Grand Coulee held back from 2.5 to 7.8 feet more of pool from June through September, November, and December while drafting from 0.8 to 9.7 feet more the remaining months. Dworshak held back the pool in May through December from 4.9 feet to 63.9 feet more while drafting from 8.7 ft to 31.5 feet more in January through April.

### 7.6.7. Summary Tables.

The following tables give a summary of the results for comparison between the base case JD1 and alternatives JD2-JD7. Table 30 provides the system generation for each alternative for each period, the average annual generation. Table 31 provides the difference in system generation between JD1 and each alternative. Table 32 provides the generation for each alternative for John Day for each period. Table 33 provides the difference in John Day Generation from the base case to each alternative. Tables 34 and 35 provides the generation at McNary and the difference in the generation at McNary between the base case and each alternative. Table 36 provides the generation for each alternative for each of Lower Snake River projects, and the totals for these projects for each period. Table 37 shows the generation for Libby, Hungry Horse, Grand Coulee, and Dworshak for each alternative for each period. Table 38 shows the average end of month elevations for Libby, Hungry Horse, Grand Coulee, and Dworshak. Tables 39, 40 and 41 show Lower Granite's regulated flow for each alternative, the difference in the Lower Granite regulated flow for each alternative from the JD1, and the number of years the Lower Granite flow objectives were met out of the 60 year study. Tables 42, 43, and 44, show the McNary regulated flow for each alternative, the difference in the McNary regulated flow for each alternative from JD1, and the number of years the Lower Granite flow objectives were met out of the 60 year study**.** It should be noted, that for tables 31, 33, 35, and 40, a negative value indicates that the subject alternative has a greater value than the base case.

**Table 30.**
**System Generation –aMW Average Over 60 Water Years (1928-1988)**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **JD1** | 13374 | 10610 | 9186 | 9347 | 11111 | 13117 | 16858 | 15015 | 13597 | 14954 | 17185 | 18202 | 18361 | 143089 | 13930 |
| **JD2** | 12802 | 10136 | 8866 | 9052 | 10795 | 12630 | 16379 | 14425 | 12995 | 14026 | 16388 | 17299 | 17617 | 13749 | 13373 |
| **JD3** | 11754 | 9604 | 8396 | 8372 | 10203 | 11669 | 15182 | 13297 | 11459 | 12040 | 14245 | 15239 | 15754 | 12617 | 12167 |
| **JD4** | 11742 | 9475 | 8464 | 8428 | 10303 | 11641 | 15329 | 13439 | 11482 | 11742 | 14334 | 15284 | 15777 | 12481 | 12189 |
| **JD5** | 12395 | 9984 | 8663 | 8696 | 10411 | 12096 | 15683 | 13758 | 12305 | 13112 | 15568 | 16602 | 17022 | 13360 | 12843 |
| **JD6** | 11249 | 9300 | 8210 | 8155 | 9804 | 11186 | 14336 | 12554 | 10753 | 11174 | 13420 | 14583 | 15101 | 12059 | 11609 |
| **JD7** | 9945 | 8495 | 8241 | 8964 | 10518 | 12150 | 15555 | 13134 | 11223 | 11892 | 12679 | 14054 | 13731 | 11406 | 11706 |

**Table 31.**
**Difference in System Generation from Alternative JD1 –aMW Average Over 60 Water Years (1928-1988)**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| JD1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| JD2 | 572 | 474 | 320 | 295 | 316 | 487 | 479 | 590 | 602 | 928 | 797 | 903 | 744 | 559 | 557 |
| JD3 | 1620 | 1006 | 790 | 975 | 908 | 1448 | 1676 | 1718 | 2138 | 2914 | 2940 | 2963 | 2607 | 1691 | 1763 |
| JD4 | 1632 | 1135 | 722 | 919 | 808 | 1476 | 1529 | 1576 | 2115 | 3212 | 2851 | 2918 | 2584 | 1827 | 1741 |
| JD5 | 979 | 626 | 523 | 651 | 700 | 1021 | 1175 | 1257 | 1292 | 1842 | 1617 | 1600 | 1339 | 948 | 1087 |
| JD6 | 2125 | 1310 | 976 | 1192 | 1307 | 1931 | 2522 | 2461 | 2844 | 3780 | 3765 | 3619 | 3260 | 2249 | 2321 |
| JD7 | 3429 | 2115 | 945 | 383 | 593 | 967 | 1303 | 1881 | 2374 | 3062 | 4506 | 4148 | 4630 | 2902 | 2224 |

**Table 32.**
**John Day Generation –aMW Average Over 60 Water Years (1928-1988)**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| JD1 | 897 | 651 | 715 | 747 | 860 | 1061 | 1478 | 1320 | 1242 | 1492 | 1514 | 1544 | 1494 | 1005 | 1146 |
| JD2 | 400 | 291 | 341 | 384 | 430 | 522 | 720 | 640 | 606 | 707 | 693 | 674 | 650 | 447 | 539 |
| JD3 | 401 | 300 | 358 | 389 | 435 | 525 | 713 | 640 | 599 | 681 | 688 | 674 | 651 | 453 | 540 |
| JD4 | 392 | 288 | 370 | 397 | 442 | 517 | 725 | 646 | 602 | 664 | 686 | 676 | 650 | 443 | 541 |
| JD5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| JD6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| JD7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Table 33.**
**Difference in John Day Generation from Alternative JD1-- aMW Average Over 60 Water Years ( 1929-1988)**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **JD1** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **JD2** | 497 | 360 | 374 | 363 | 430 | 539 | 758 | 680 | 636 | 785 | 821 | 870 | 844 | 558 | 607 |
| **JD3** | 496 | 351 | 357 | 358 | 425 | 536 | 765 | 680 | 643 | 811 | 826 | 870 | 843 | 552 | 606 |
| **JD4** | 505 | 363 | 345 | 350 | 418 | 544 | 753 | 674 | 640 | 828 | 828 | 868 | 844 | 562 | 605 |
| **JD5** | 897 | 651 | 715 | 747 | 860 | 1061 | 1478 | 1320 | 1242 | 1492 | 1514 | 1544 | 1494 | 1005 | 1146 |
| **JD6** | 897 | 651 | 715 | 747 | 860 | 1061 | 1478 | 1320 | 1242 | 1492 | 1514 | 1544 | 1494 | 1005 | 1146 |
| **JD7** | 897 | 651 | 715 | 747 | 860 | 1061 | 1478 | 1320 | 1242 | 1492 | 1514 | 1544 | 1494 | 1005 | 1146 |

**Table 34.**
**McNary Generation --aMW Average Over 60 Water Years ( 1929-1988)**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| JD1 | 843 | 654 | 490 | 514 | 572 | 705 | 963 | 865 | 801 | 913 | 938 | 952 | 877 | 904 | 777 |
| JD2 | 936 | 738 | 564 | 589 | 655 | 790 | 1011 | 943 | 878 | 968 | 997 | 1013 | 947 | 973 | 849 |
| JD3 | 927 | 741 | 591 | 597 | 667 | 798 | 993 | 934 | 872 | 953 | 990 | 1016 | 951 | 973 | 850 |
| JD4 | 908 | 712 | 611 | 609 | 677 | 785 | 999 | 941 | 875 | 939 | 986 | 1019 | 947 | 957 | 850 |
| JD5 | 932 | 739 | 572 | 592 | 660 | 793 | 1004 | 938 | 873 | 965 | 993 | 1014 | 948 | 972 | 849 |
| JD6 | 926 | 743 | 603 | 609 | 672 | 806 | 985 | 928 | 870 | 939 | 985 | 1015 | 950 | 972 | 851 |
| JD7 | 778 | 657 | 598 | 644 | 729 | 851 | 1029 | 984 | 914 | 968 | 925 | 972 | 873 | 900 | 847 |

**Table 35.**
**Difference in McNary Generation from Alternative JD1 --aMW Average over 60 Water Years (1928-1988)**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| JD1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| JD2 | -93 | -84 | -74 | -75 | -83 | -85 | -48 | -78 | -77 | -55 | -59 | -61 | -70 | -69 | -72 |
| JD3 | -84 | -87 | -101 | -83 | -95 | -93 | -30 | -69 | -71 | -40 | -52 | -64 | -74 | -69 | -73 |
| JD4 | -65 | -58 | -121 | -95 | -105 | -80 | -36 | -76 | -74 | -26 | -48 | -67 | -70 | -53 | -73 |
| JD5 | -89 | -85 | -82 | -78 | -88 | -88 | -41 | -73 | -72 | -52 | -55 | -62 | -71 | -68 | -72 |
| JD6 | -83 | -89 | -113 | -95 | -100 | -101 | -22 | -63 | -69 | -26 | -47 | -63 | -73 | -68 | -74 |
| JD7 | 65 | -3 | -108 | -130 | -157 | -146 | -66 | -119 | -113 | -55 | 13 | -20 | 4 | 4 | -70 |

**Table 36.**
**Alternative JD1 Generation at Lower Granite, Little Goose, Lower Monumental, and Ice Harbor --aMW Average Over 60 Water Years (1928-1988)**

| Project | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **L. Granite** | 244 | 195 | 182 | 178 | 146 | 242 | 252 | 284 | 358 | 466 | 559 | 610 | 605 | 347 | 329 |
| **L. Goose** | 238 | 190 | 178 | 185 | 148 | 237 | 247 | 278 | 350 | 451 | 518 | 561 | 573 | 339 | 317 |
| **L. Monumental** | 245 | 196 | 177 | 188 | 151 | 245 | 258 | 300 | 366 | 490 | 573 | 618 | 610 | 353 | 335 |
| **Ice Harbor** | 49 | 49 | 172 | 186 | 150 | 240 | 252 | 292 | 350 | 205 | 281 | 325 | 295 | 70 | 219 |
| **Total Generation** | 776 | 630 | 709 | 737 | 595 | 964 | 1009 | 1154 | 1424 | 1612 | 1931 | 2114 | 2083 | 1109 | 1200 |

**Table 37.**
**Generation at Libby, Hungry Horse, Grand Coulee, and Dworshak- aMW Average Over 60 Water Years (1928-1988)**

**Libby**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **JD1** | 338 | 278 | 234 | 142 | 160 | 303 | 300 | 206 | 96 | 92 | 129 | 132 | 263 | 451 | 226 |
| **JD2** | 337 | 275 | 246 | 141 | 158 | 292 | 299 | 207 | 98 | 92 | 129 | 131 | 263 | 450 | 226 |
| **JD3** | 335 | 272 | 282 | 143 | 155 | 254 | 298 | 208 | 107 | 91 | 126 | 122 | 264 | 453 | 225 |
| **JD4** | 336 | 273 | 280 | 146 | 154 | 254 | 297 | 209 | 107 | 91 | 126 | 123 | 263 | 452 | 225 |
| **JD5** | 337 | 275 | 259 | 141 | 160 | 278 | 299 | 207 | 103 | 93 | 126 | 125 | 263 | 450 | 226 |
| **JD6** | 336 | 273 | 296 | 151 | 156 | 231 | 295 | 210 | 110 | 91 | 125 | 123 | 263 | 452 | 225 |
| **JD7** | 229 | 203 | 162 | 234 | 289 | 424 | 300 | 206 | 109 | 91 | 125 | 121 | 263 | 304 | 228 |

**Hungry Horse**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **JD1** | 175 | 207 | 73 | 70 | 55 | 91 | 145 | 129 | 109 | 121 | 227 | 92 | 79 | 127 | 112 |
| **JD2** | 172 | 204 | 72 | 69 | 55 | 89 | 171 | 129 | 96 | 112 | 220 | 91 | 79 | 126 | 111 |
| **JD3** | 165 | 198 | 71 | 68 | 54 | 88 | 212 | 133 | 98 | 91 | 201 | 78 | 74 | 114 | 110 |
| **JD4** | 174 | 188 | 70 | 68 | 54 | 88 | 204 | 138 | 98 | 93 | 207 | 80 | 74 | 118 | 111 |
| **JD5** | 166 | 200 | 72 | 69 | 54 | 88 | 191 | 132 | 95 | 100 | 218 | 86 | 75 | 122 | 111 |
| **JD6** | 162 | 194 | 71 | 68 | 54 | 88 | 238 | 140 | 90 | 88 | 187 | 69 | 72 | 104 | 110 |
| **JD7** | 115 | 177 | 94 | 113 | 68 | 137 | 234 | 173 | 94 | 77 | 115 | 65 | 66 | 45 | 111 |

**Table 37 (cont.).**
**Generation at Libby, Hungry Horse, Grand Coulee, and Dworshak- aMW Average Over 60 Water Years (1928-1988)**

**Grand Coulee**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **JD1** | 2790 | 2133 | 1502 | 1586 | 1916 | 2175 | 3365 | 2616 | 2068 | 2178 | 2805 | 3128 | 3139 | 2742 | 2433 |
| **JD2** | 2787 | 2134 | 1508 | 1587 | 1922 | 2165 | 3408 | 2599 | 2037 | 2105 | 2801 | 3115 | 3144 | 2749 | 2429 |
| **JD3** | 2749 | 2142 | 1552 | 1613 | 1936 | 2170 | 3330 | 2579 | 2010 | 2013 | 2770 | 3103 | 3158 | 2765 | 2422 |
| **JD4** | 2771 | 2136 | 1534 | 1615 | 1929 | 2171 | 3320 | 2598 | 2015 | 1942 | 2869 | 3117 | 3140 | 2771 | 2423 |
| **JD5** | 2772 | 2135 | 1527 | 1596 | 1934 | 2168 | 3403 | 2574 | 2018 | 2055 | 2782 | 3106 | 3144 | 2753 | 2425 |
| **JD6** | 2745 | 2152 | 1582 | 1653 | 1942 | 2184 | 3284 | 2541 | 1991 | 1963 | 2728 | 3087 | 3161 | 2754 | 2415 |
| **JD7** | 2400 | 2013 | 1618 | 1820 | 1999 | 2299 | 3572 | 2651 | 2119 | 2161 | 2556 | 2983 | 2869 | 2657 | 2430 |

**Dworshak**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **JD1** | 333 | 276 | 245 | 90 | 112 | 129 | 72 | 185 | 198 | 271 | 349 | 252 | 268 | 312 | 207 |
| **JD2** | 332 | 276 | 255 | 91 | 116 | 128 | 71 | 184 | 197 | 270 | 351 | 249 | 260 | 312 | 207 |
| **JD3** | 334 | 276 | 296 | 93 | 124 | 143 | 69 | 172 | 188 | 279 | 316 | 235 | 260 | 304 | 208 |
| **JD4** | 287 | 203 | 386 | 106 | 225 | 158 | 233 | 223 | 183 | 200 | 193 | 251 | 311 | 188 | 226 |
| **JD5** | 332 | 276 | 271 | 92 | 120 | 135 | 69 | 180 | 192 | 246 | 339 | 249 | 260 | 307 | 206 |
| **JD6** | 335 | 277 | 318 | 105 | 132 | 158 | 67 | 153 | 175 | 223 | 318 | 242 | 249 | 306 | 207 |
| **JD7** | 149 | 96 | 312 | 134 | 312 | 380 | 365 | 283 | 213 | 196 | 210 | 145 | 153 | 157 | 232 |

**Table 38.**
**Average End of Month Elevations -- ft. Average Over 60 Water Years (1928-1988)**

**Libby**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **JD1** | 2442.2 | 2439.1 | 2433.0 | 2431.7 | 2427.9 | 2411.0 | 2384.9 | 2365.3 | 2361.3 | 2361.3 | 2363.6 | 2403.4 | 2443.9 | 2445.2 | 2409.2 |
| **JD2** | 2442.1 | 2439.1 | 2432.2 | 2430.9 | 2427.1 | 2411.0 | 2385.0 | 2365.3 | 2361.3 | 2361.3 | 2363.5 | 2403.1 | 2443.7 | 2445.1 | 2409.0 |
| **JD3** | 2442.1 | 2439.1 | 2429.6 | 2428.0 | 2424.3 | 2411.0 | 2385.3 | 2365.4 | 2360.8 | 2360.9 | 2363.2 | 2403.5 | 2443.8 | 2444.9 | 2408.3 |
| **JD4** | 2442.1 | 2439.1 | 2429.8 | 2428.0 | 2424.4 | 2411.0 | 2385.4 | 2365.4 | 2360.9 | 2360.9 | 2363.2 | 2403.5 | 2443.8 | 2445.0 | 2408.3 |
| **JD5** | 2442.2 | 2439.1 | 2431.3 | 2430.0 | 2426.1 | 2411.0 | 2385.1 | 2365.3 | 2361.3 | 2361.2 | 2363.5 | 2403.2 | 2443.7 | 2445.1 | 2408.8 |
| **JD6** | 2442.1 | 2439.1 | 2428.7 | 2426.6 | 2422.7 | 2411.0 | 2385.8 | 2365.6 | 2360.6 | 2360.6 | 2362.9 | 2403.2 | 2443.8 | 2445.0 | 2407.9 |
| **JD7** | 2454.8 | 2454.4 | 2453.8 | 2448.0 | 2436.6 | 2411.0 | 2384.9 | 2365.3 | 2360.4 | 2360.5 | 2362.7 | 2403.1 | 2443.7 | 2454.1 | 2414.8 |

**Hungry Horse**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **JD1** | 3548.3 | 3541.0 | 3537.4 | 3534.4 | 3533.2 | 3528.6 | 3517.4 | 3508.1 | 3499.7 | 3497.7 | 3492.9 | 3525.4 | 3552.4 | 3552.6 | 3527.4 |
| **JD2** | 3547.4 | 3540.3 | 3536.7 | 3533.8 | 3532.6 | 3528.1 | 3514.3 | 3504.6 | 3497.6 | 3496.1 | 3491.6 | 3524.5 | 3551.6 | 3551.9 | 3526.1 |
| **JD3** | 3543.2 | 3536.2 | 3532.6 | 3529.7 | 3528.5 | 3524.0 | 3505.3 | 3493.7 | 3483.9 | 3483.7 | 3481.1 | 3517.4 | 3545.7 | 3547.0 | 3519.2 |
| **JD4** | 3543.1 | 3536.5 | 3533.1 | 3530.2 | 3529.0 | 3524.5 | 3506.7 | 3494.8 | 3485.6 | 3485.3 | 3482.2 | 3518.0 | 3546.2 | 3547.2 | 3519.9 |
| **JD5** | 3545.5 | 3538.4 | 3534.8 | 3532.0 | 3530.8 | 3526.3 | 3510.2 | 3499.3 | 3491.4 | 3490.6 | 3486.5 | 3520.9 | 3548.6 | 3549.3 | 3522.8 |
| **JD6** | 3541.4 | 3534.5 | 3530.9 | 3527.9 | 3526.7 | 3522.2 | 3500.2 | 3486.6 | 3476.9 | 3477.1 | 3475.8 | 3514.1 | 3542.9 | 3545.0 | 3515.7 |
| **JD7** | 3551.7 | 3545.1 | 3539.5 | 3532.8 | 3530.3 | 3521.3 | 3500.2 | 3484.5 | 3476.9 | 3477.4 | 3480.9 | 3518.5 | 3547.3 | 3553.8 | 3519.4 |

**Table 38 (cont.).**
**Average End of Month Elevations -- ft. Average Over 60 Water Years (1928-1988)**

**Grand Coulee**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **JD1** | 1282.0 | 1280.2 | 1285.2 | 1288.2 | 1285.1 | 1283.4 | 1268.4 | 1257.9 | 1245.4 | 1239.3 | 1233.5 | 1250.6 | 1282.3 | 1287.0 | 1270.9 |
| **JD2** | 1282.0 | 1280.1 | 1285.2 | 1288.0 | 1284.8 | 1282.7 | 1266.0 | 1255.8 | 1244.6 | 1239.3 | 1233.4 | 1250.5 | 1282.3 | 1287.0 | 1270.3 |
| **JD3** | 1281.9 | 1280.1 | 1284.7 | 1286.8 | 1282.8 | 1278.3 | 1262.1 | 1252.9 | 1243.3 | 1238.9 | 1233.0 | 1250.2 | 1282.9 | 1286.9 | 1269.0 |
| **JD4** | 1281.6 | 1280.1 | 1284.7 | 1287.0 | 1283.2 | 1278.8 | 1262.9 | 1253.1 | 1243.5 | 1241.4 | 1233.1 | 1249.4 | 1282.9 | 1286.8 | 1269.2 |
| **JD5** | 1282.0 | 1280.1 | 1284.9 | 1287.6 | 1284.0 | 1280.9 | 1263.3 | 1254.0 | 1243.9 | 1239.1 | 1233.3 | 1250.2 | 1282.3 | 1286.9 | 1269.6 |
| **JD6** | 1281.9 | 1280.1 | 1284.5 | 1286.0 | 1281.8 | 1275.5 | 1259.0 | 1250.8 | 1240.9 | 1237.7 | 1232.2 | 1250.1 | 1283.0 | 1286.9 | 1267.9 |
| **JD7** | 1288.9 | 1288.0 | 1287.7 | 1287.4 | 1285.6 | 1285.8 | 1265.0 | 1253.2 | 1239.0 | 1229.6 | 1226.1 | 1246.9 | 1287.3 | 1290.0 | 1270.4 |

**Dworshak**

| Alternative | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **JD1** | 1546.1 | 1532.1 | 1510.2 | 1507.0 | 1505.2 | 1506.0 | 1512.7 | 1507.6 | 1502.4 | 1507.2 | 1507.7 | 1558.1 | 1577.9 | 1560.8 | 1524.5 |
| **JD2** | 1546.1 | 1532.1 | 1508.9 | 1505.5 | 1503.1 | 1504.0 | 1510.9 | 1505.8 | 1500.9 | 1505.9 | 1506.5 | 1557.2 | 1577.9 | 1560.7 | 1523.3 |
| **JD3** | 1546.1 | 1532.0 | 1503.2 | 1499.1 | 1495.1 | 1493.6 | 1501.2 | 1498.1 | 1494.8 | 1499.7 | 1504.1 | 1556.4 | 1577.0 | 1560.8 | 1518.4 |
| **JD4** | 1557.2 | 1551.0 | 1516.4 | 1512.1 | 1497.4 | 1493.8 | 1477.1 | 1465.1 | 1466.2 | 1476.0 | 1495.6 | 1548.5 | 1568.3 | 1564.4 | 1512.4 |
| **JD5** | 1546.1 | 1532.1 | 1506.8 | 1503.0 | 1499.8 | 1499.6 | 1506.8 | 1502.3 | 1498.1 | 1504.4 | 1506.0 | 1556.8 | 1577.4 | 1560.7 | 1521.3 |
| **JD6** | 1546.1 | 1532.0 | 1500.2 | 1494.0 | 1488.6 | 1484.3 | 1492.4 | 1492.2 | 1491.3 | 1499.4 | 1503.5 | 1555.2 | 1577.2 | 1560.9 | 1514.7 |
| **JD7** | 1594.8 | 1593.9 | 1575.6 | 1570.9 | 1553.3 | 1528.2 | 1496.9 | 1476.4 | 1470.9 | 1480.7 | 1499.0 | 1563.0 | 1595.3 | 1596.7 | 1542.6 |

**Table 39.**
**Lower Granite Regulated Flow -- cfs. Average Over 60 Water Years (1928-1988)**

| | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Natural** | 22992 | 20701 | 22548 | 25293 | 28950 | 33461 | 34604 | 39665 | 49829 | 73196 | 91287 | 121483 | 110485 | 40559 | 50914 |
| **JD1** | 35943 | 28877 | 27025 | 26394 | 21217 | 33607 | 35078 | 39486 | 49839 | 73135 | 96830 | 108063 | 101756 | 51118 | 50915 |
| **JD2** | 35923 | 28877 | 27267 | 26432 | 21404 | 33500 | 35058 | 39472 | 49812 | 73127 | 96820 | 107985 | 101561 | 51118 | 50916 |
| **JD3** | 35958 | 28878 | 28333 | 26507 | 22490 | 33800 | 34971 | 39131 | 49604 | 71962 | 95241 | 107680 | 101523 | 50918 | 50915 |
| **JD4** | 30769 | 23805 | 32619 | 28586 | 24726 | 31533 | 39582 | 40370 | 50353 | 70963 | 90250 | 107572 | 101754 | 46198 | 50933 |
| **JD5** | 35902 | 28875 | 27680 | 26464 | 21631 | 33621 | 35029 | 39373 | 49709 | 72571 | 96454 | 107992 | 101570 | 51011 | 50915 |
| **JD6** | 35995 | 28898 | 28894 | 26851 | 22825 | 34140 | 34952 | 38594 | 49208 | 70627 | 95487 | 107824 | 101207 | 50928 | 50911 |
| **JD7** | 24522 | 21452 | 28315 | 26675 | 31618 | 39725 | 41731 | 47515 | 51331 | 70213 | 84730 | 104636 | 98408 | 40998 | 50951 |

**Table 40.**
**Difference in Lower Granite Regulated Flow from Base Case -- cfs. Average Over 60 Water Years (1928-1988)**

| | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **JD1-JD2** | 20 | 0 | -242 | -38 | -187 | 107 | 20 | 14 | 27 | 8 | 10 | 78 | 195 | 0 |
| **JD1-JD3** | -15 | -1 | -1308 | -113 | -1273 | -193 | 107 | 355 | 235 | 1173 | 1589 | 383 | 233 | 200 |
| **JD1-JD4** | 5174 | 5072 | -5594 | -2192 | -3509 | 2074 | -4504 | -884 | -514 | 2172 | 6580 | 491 | 2 | 4920 |
| **JD1-JD5** | 41 | 2 | -655 | -70 | -414 | -14 | 49 | 113 | 130 | 564 | 376 | 71 | 186 | 107 |
| **JD1-JD6** | -52 | -21 | -1869 | -457 | -1608 | -533 | 126 | 892 | 631 | 2508 | 1343 | 239 | 549 | 190 |
| **JD1-JD7** | 11421 | 7425 | -1290 | -281 | -10401 | -6118 | -6653 | -8029 | -1492 | 2922 | 12100 | 3427 | 3348 | 10120 |

**Table 41.**
**Number of years Lower Granite Flow Objectives Were Met-- Number of years out of sixty.**

| | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Natural** | 0 | 0 | | | | | | | | 27 | 38 | 52 | 57 | 11 |
| **JD1** | 0 | 0 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 27 | 44 | 54 | 57 | 33 |
| **JD2** | 0 | 0 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 27 | 44 | 53 | 57 | 33 |
| **JD3** | 0 | 0 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 27 | 44 | 52 | 57 | 33 |
| **JD4** | 0 | 0 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| **JD5** | 0 | 0 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 27 | 44 | 52 | 57 | 32 |
| **JD6** | 0 | 0 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 27 | 43 | 52 | 57 | 32 |
| **JD7** | 0 | 0 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

**Table 42.**
**McNary Regulated Flow -- cfs. Average Over 60 Water Years (1928-1988)**

| | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL | Ave. Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Natural** | 150664 | 117495 | 93184 | 82595 | 84681 | 87559 | 84906 | 95759 | 116335 | 175051 | 251184 | 415532 | 463462 | 251428 | 176887 |
| **JD1** | 165564 | 127953 | 95582 | 100150 | 111520 | 137610 | 194804 | 171842 | 159844 | 195270 | 249338 | 281472 | 273771 | 185525 | 173432 |
| **JD2** | 165918 | 128175 | 96076 | 100240 | 112043 | 137142 | 197041 | 171997 | 159032 | 191028 | 248996 | 280743 | 273621 | 185916 | 173410 |
| **JD3** | 163819 | 128531 | 100814 | 101619 | 114187 | 138657 | 195432 | 171731 | 158184 | 183707 | 246271 | 279853 | 273847 | 186035 | 173461 |
| **JD4** | 159802 | 123269 | 104322 | 103737 | 115997 | 136280 | 199299 | 173682 | 159085 | 178593 | 245817 | 280625 | 273374 | 181627 | 173481 |
| **JD5** | 165242 | 128324 | 97370 | 100747 | 112968 | 137782 | 197652 | 171525 | 158529 | 187946 | 247540 | 280124 | 273374 | 185992 | 173383 |
| **JD6** | 163705 | 129009 | 102775 | 103827 | 115025 | 140210 | 194323 | 170211 | 157415 | 180364 | 245033 | 279480 | 273525 | 185540 | 173449 |
| **JD7** | 134897 | 112671 | 101959 | 110044 | 125457 | 148385 | 211350 | 182984 | 165331 | 191387 | 228586 | 274389 | 257814 | 170246 | 173478 |

**Table 43.**
**Difference in McNary Regulated Flow from the Base Case -- cfs. Average Over 60 Water Years (1928-1988)**

| | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **JD1-JD2** | -354 | -222 | -494 | -90 | -523 | 468 | -2237 | -155 | 812 | 4242 | 342 | 729 | 150 | -391 |
| **JD1-JD3** | 1745 | -578 | -5232 | -1469 | -2667 | -1047 | -628 | 111 | 1660 | 11563 | 3067 | 1619 | -76 | -510 |
| **JD1-JD4** | 5762 | 4684 | -8740 | -3587 | -4477 | 1330 | -4495 | -1840 | 759 | 16677 | 3521 | 847 | 397 | 3898 |
| **JD1-JD5** | 322 | -371 | -1788 | -597 | -1448 | -172 | -2848 | 317 | 1315 | 7324 | 1798 | 1348 | 397 | -467 |
| **JD1-JD6** | 1859 | -1056 | -7193 | -3677 | -3505 | -2600 | 481 | 1631 | 2429 | 14906 | 4305 | 1992 | 246 | -15 |
| **JD1-JD7** | 30667 | 15282 | -6377 | -9894 | -13937 | -10775 | -16546 | -11142 | -5487 | 3883 | 20752 | 7083 | 15957 | 15279 |

**Table 44.**
**Years McNary Flow Objectives were Met - Number of Years out of sixty**

| | AG1 | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | APR | MAY | JUN | JUL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Natural** | 5 | 2 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 34 | 59 | 60 | 40 |
| **JD1** | 19 | 3 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 42 | 49 | 32 | 25 |
| **JD2** | 19 | 4 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 42 | 48 | 32 | 25 |
| **JD3** | 19 | 3 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 42 | 50 | 35 | 23 |
| **JD4** | 15 | 2 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 42 | 48 | 37 | 22 |
| **JD5** | 19 | 4 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 42 | 49 | 33 | 25 |
| **JD6** | 19 | 3 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 41 | 49 | 37 | 23 |
| **JD7** | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

## 7.7. Future Studies.

If the John Day Drawdown Phase II Study were to be implemented, additional details to refine the hydroregulation studies would be required. The following items have been identified as information needed for a more detailed hydroregulation study or possible additional studies of the John Day Drawdown alternatives.

### 7.7.1. Turbine Data.

A better estimate of turbine efficiencies and flow for the John Day turbines for the Drawdown to Spillway alternative will be required. Currently, the estimated error is 10 to 20 percent, according to the John Day Drawdown Phase I Study, Structural Alternatives 60 percent Submittal, page 3-7. The HYSSR input data would need to be revised to reflect the new turbine data.

### 7.7.2. Tailwater vs. Discharge Curve for McNary.

The Tailwater vs. Discharge Curve used for the hydroregulations for the spillway and natural river options were based on data in the "McNary Dam Columbia River, Oregon & Washington Hydraulic Model Investigation, Report 20-1 by the Bonneville, Hydraulic Laboratory. A hydrologic study conducted for the John Day Drawdown Phase I Study developed new curves for the McNary tailwater when John Day Dam is operated at spillway and natural river conditions. These curves were not available during the hydroregulation studies. The new curves are approximately one to two feet lower than that used in the hydroregulations. The hydroregulations may need to be adjusted to reflect the new data.

### 7.7.3. Future Base Conditions.

Base Case conditions may change between the Phase I and Phase II studies. These conditions may include updates to flood control, fisheries flow objectives, draft limits, fish spill criteria, resident fish criteria, loads, and other non-power requirements. The Phase II hydroregulations should include the new requirements.

### 7.7.4. New Alternatives.

New alternatives may be identified as viable alternatives during, public review of the Phase I report. Hydroregulations for these alternatives may be prepared.

## 7.8. Base Case Alternative JD1 Specifications.

The Base Case Alternative JD1 specifications can be found in attachment 1 of this document.

# Attachment 1

**Date:** April 30, 1999 **Alternative No.: JD1**

Revision No.:1

**Purpose of Study**: A Continuous Study of the system operations under the 1995 NMFS Biological Opinion, the 1998 Supplemental Biological Opinion (steelhead), and the forthcoming 1999 Supplemental Biological Opinion (sturgeon, bull trout, and anadromous fish) is needed to serve as the base case (JD1) for the John Day Drawdown reconnaissance study. All alternatives under the John Day Drawdown study will be compared to the base case.

**AER Step:**

- USACE will perform **one regulation** for the base condition and each alternative. The regulation will include all the requirements within this Actual Energy Regulation(AER) Step specification.
- This is a **CONTINUOUS** study based on OY99 PNCA data submittal. The study will begin on 1 Aug 1928 and end on 31 July 1988, a 60-year study.
- All **FELCC** is taken from the OY99 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 objective flows at McNary and Lower Granite. FELCC will be created by adding Hydro-Independent generation 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.
- This AER study has a **secondary market limit** of 9,000 aMW.
- The **Regulated Hydro** projects are attached.
- The **Hydro-Independent** projects are based upon PNCA and are attached.
- The 60 years of **Modified Stream flows** used are from "Modified Streamflows 1990 Level of Irrigation", dated July 1993. They contain 1990 level irrigation depletion's. Adjustments to these 1990 level modified stream flows are due to the Bureau of Reclamation's updated Grand Coulee pumping schedule for the Columbia Basin Project. This pumping schedule is included in the BOR's February 1, 1998 preliminary PNCA data submittal.
- 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, 1999 PNCA Data Submittal byUSACE. 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 IJC 1938 Order at Kootenay Lake.

- **VECC's** are calculated using OY99 Power Discharge Requirements (PDR's), distribution factors and forecast errors, which are used in PNCA planning. Canadian Treaty projects are calculated using AOP99 PDR's. The volume forecast for all projects are based on actual runoff.
- **The Critical Rule Curve** (CRC) used is the CRC1 taken from the 1998-99 Final Regulation – Water Year 1936-37. Only one rule curve is used for this study because the preceding Final Regulations for 1995-95, 1996-97, and 1997-98 had critical periods less than one year.
- **Storage reservoirs are initialized** to full on 1 August 1928, with the following exceptions: Mica is initialized to July Mica target; Grand Coulee is initialized to 1285.0 feet (2417.1 ksfd); Brownlee is initialized to 2052.0 feet (331.5 ksfd); Libby is initialized to 2449 feet (2281.3 ksfd); John Day is initialized to 262.5 feet (127.7 ksfd), Corra Linn is initialized to 1743.32 feet(226.7 ksfd), Hungry Horse is initialized to 3550 feet (1427.7 ksfd) and Dworshak is initialized to 1560.0 feet (676.2 ksfd).
- All **project non-power requirements** will follow those from PNCA plant data book updated 30 Sept 1996 or which were submitted for OY99 PNCA planning process on the February 1, 1998, except as noted within this specification.
- **Mica, Duncan and Arrow** will be on their AOP99 operations including changes agreed to by the Entities as described in the DOP99 except that this regulation incorporates the Arrow Total method of computing VECC. The Canadian Treaty 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.
- **Libby** is operated in proportional draft mode September through December to meet December URC (2411.0 feet, 1502.2 ksfd). From January 1st through April 15th, Libby is operated on minimum flow or flood control objectives as defined in the BiOP. It should be noted that Libby does violate URC for Corra Linn's IJC operation. Libby's maximum outflow from May 1st through August 31st is powerhouse hydraulic capacity without spill. From May 1$^{st}$ through June 30th, Libby is operated for protection of sturgeon in all years by supporting Bonners Ferry minimum flows. The 1996 Draft Sturgeon Recovery plan objectives reflect the May 1, April-August forecast. The following table describes the objectives:

WHITE STURGEON FLOW OBJECTIVES AT BONNERS FERRY - KCFS

| | 0 ≤ FC<4.8 | 4.8 ≤ FC <6.0 MAF | 6.0≤ FC <6.7 MAF | 6.7≤ FC <8.1 MAF | 8.1≤ FC <8.9 MAF | 8.9< FC MAF |
|---|---|---|---|---|---|---|
| May | 4.000 | 7.87 | 9.807 | 14.159 | 21.420 | 26.256 |
| June | 4.000 | 12.000 | 16.000 | 25.000 | 40.000 | 50.000 |

FC = April – August Volume Forecast at Libby

* = Release from Libby which may be increased in May if required for flood control and July for salmon

From July 1st through August 31st, Libby is operated on a straightline basis for bull trout and salmon objectives. If the June 30 elevation is greater than 2439 ft, the July 31, August 15, and August 31 elevations will be targeted so that the August 31 elevation is at El. 2439 feet The water volume on June 30th above El 2439 will be released over the next two months at a constant rate in addition to the release of the natural inflows. When the June 30 elevation is less than El. 2439, Libby will target 2439 ft on July 31, August 15, and August 31.

- **Hungry Horse** is operated in proportional draft mode September through December subject to draft limits of 3539, 3537, 3535 and 3533.0 feet (1301.6, 1280.1, 1258.6, and 1237.2 ksfd), respectively, as provided by the Bureau of Reclamation on February 25th, 1999. The reservoir storage-elevation relationship will reflect 3 percent bank storage. From January through March, Hungry Horse is free to operate above its Variable Draft Limits (VDL's) as defined in the BiOP (Calculated according to instructions in the 1998-99 PNCA Operating Procedures), but no higher than flood control. The VDL's were provided by the Bureau of Reclamation in February, 1999. For the first half of April, Hungry Horse drafts for Priest Rapids to El. 3540 ft (1312.3 ksfd). For the second half of April through May 31st, Hungry Horse drafts for Priest Rapids and McNary flow objectives down to El. 3540. The project will attempt to refill by June 30th to El. 3560 feet (1548.5 ksfd). On July 31, August 15 and August 31, Hungry Horse will draft to 3550, 3545 and 3540.0 feet (1427.7, 1370.0, and 1312.3 ksfd) respectively, 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** drafts for power in September through November to 2060.0, 2054, and 2051 feet (465.7, 384.4, and 251.6 ksfd) and stays at 2051 in December. In January through March, the draft limit is 2055 (428.7 ksfd). For the first and second half of April, Albeni Falls is operated to 2056.0 feet (473.0 ksfd). From May through August Albeni Falls is operated to 2062.0 (753.1 ksfd).
- **Grand Coulee** is operated to meet FELCC September through December subject to draft limits of 1283, 1280, 1275 and 1265 (4315.4, 4197.0, 3999.7, 3644.5 ksfd) respectively. Grand Coulee augments for Vernita Bar during December through May, and may draft to the storage lower bounds of 1208 feet (1977.3 ksfd) if needed for Vernita Bar objectives. In January through March, VDL's are used for Grand Coulee which reflect the expected April 10th URC and storage needed for the appropriate Vernita Bar minimum flow

requirement. Resident fish draft limits for January, February, and March are 1260 ft, 1250 ft, and 1240 ft (3468.1, 3137.2, and 2820.9 ksfd), respectively. The higher of the resident fish draft limits and VDL's will be used. Grand Coulee may draft to 1250 by April 15th for Priest Rapids flow augmentation for the first half of April. For April 30th, May 31st, and June 30th, Grand Coulee may draft to 1250, 1240, and 1280 ft, for McNary and Priest Rapids flow augmentation. For July 31st, August 15th, and August 31st, Grand Coulee may draft to 1285, 1280, and 1280 feet (2417.1, 2216.4 and 2216.4 ksfd) for McNary flow augmentation. During all periods, when flood control is less than the draft limits, the project will draft to the flood control elevation. At-site minimum flow is equal to 30,000 cfs. Grand Coulee is subject to a drawdown limit of 1.5 feet per day (ft/day) when the pool is above El. 1260 ft, 1.3 ft/day at or below El. 1260 and above 1240, and 1.0 ft/day when the pool is at or below 1240 feet.

- **Vernita Bar** minimum flows for December through May vary by water condition, with minimum flows established as the lesser of a) 68 percent of the Wanapum's October or November flows, whichever is larger, 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. Grand Coulee will augment for Vernita Bar.
- Flow objectives for **Priest Rapids** are 135 kcfs, April 10-June 30 based on the 1998 Supplemental Biological Opinion for steelhead. The April 1-15 objective is 90 kcfs, assuming 60 kcfs at Vernita Bar minimum flow for 9 days and 135 kcfs for 6 days. Grand Coulee and Hungry Horse may augment for Priest Rapids.
- The **Upper Snake** reservoir operations adjustments to Brownlee inflows came from the Bureau of Reclamation in June 1998. 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 during February through April. In May, Brownlee will operate to flood control or 2069 ft, and in June it will fill to 2077 feet In July, the first half and second half of August, it will operate to 2052, 2043, and 2043 ft, 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 BiOP, with the exception of the first half of April through August when it operates to meet Lower Granite flow objectives. Dworshak may draft to elevation 1520, in the first half of April through May. For June, July, the first half and the second half of August, the project may draft to 1523, 1524, 1522, and 1520 feet to support Lower Granite flow objectives. In all periods, if flood control is less than the draft limits, then the project will draft for flood control. 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, 1998 PNCA data submittal.

- 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 **1percent of peak efficiency** during the period of March through November. This requirement is reflected in a hydro availability file, which limits the maximum generation capability of each project in each of the fourteen periods. The minimum powerhouse flow for McNary, John Day and The Dalles is 50 kcfs, for Bonneville is 30 kcfs, for Lower Granite, Little Goose, and Lower Monumental is 11.5 kcfs, and for Ice Harbor is 7.5 kcfs. No other hydro outages assumed.
- 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 May 20, 1998 Modified Data Submittal. The spill for fish program was developed previously using spill for fish as a percentage of the regulated flow. The Lower Snake projects will no longer use this operation. For modeling of this hydroregulation, the Lower Snake projects will spill up to their spill caps when spill occurs. Lower Granite, Little Goose, and Lower Monumental projects will spill when Lower Granite's regulated flow is greater than 85,000 cfs. The Lower Columbia projects will spill after reaching their minimum powerhouse flows. Bonneville and McNary will spill up to their spill cap and John Day and The Dalles will spill based on a percentage of their regulated flow. Spill caps and percentages are as shown below.

**1998-99 PNCA**
**Spill Caps**

| PROJECT | Daily Average Spill Cap (cfs) | Instantaneous Spill Cap (cfs) |
|---|---|---|
| Lower Granite | 22,500 | 45,000 |
| Little Goose | 30,000 | 60,000 |
| Lower Monumental | 20,000 | 40,000 |
| Ice Harbor | 58,750 | 75,000 (night)/45,000 (day) |
| McNary | 75,000 | 150,000 |
| John Day * | 82,500 / 97,500 | 180,000 |
| The Dalles | 230,000 | 230,000 |
| Bonneville | 97,500 | 120,000 (night)/75,000 (day) |

* 82,500 for April-July and 97,500 for August

**1998-99 PNCA**

**PROJECT FISHSPILL for MODELING**

Percent of Regulated Flow (%):

| PROJECT | 15Apr | 30Apr | May | Jun | Jul | 15Aug | 30Aug |
|---|---|---|---|---|---|---|---|
| John Day | 0.0 | 22.0 | 27.5 | 27.5 | 27.5 | 27.5 | 32.5 |
| The Dalles | 0.0 | 46.9 | 64.0 | 64.0 | 64.0 | 64.0 | 64.0 |

- Use a **sliding scale flow objective** of from 220,000 to 260,000 cfs **at McNary** based on The Dalles April 1, January through July volume runoff. A straight-line interpolation will be 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. Grand Coulee will augment for McNary in all periods. Libby will augment in July and August, and Hungry Horse will augment in all periods but June. In June, Hungry Horse attempts to refill.
- **Lower Granite** also has sliding scale **flow augmentation objectives**. For spring flow objectives (3 April – 20 June), when the April 1, April through July runoff forecast is less than 10 Maf, the project will run on minimum flow or URC except in May where the project will run at 60,000 cfs. For spring flows when the forecast is 10 to 16 Maf, April and June operation will be on minimum flow or URC and May flow objectives will range on a sliding scale from 60,000 to 85,000 cfs. For spring flows when the forecast is 16 to 20 Maf, objectives range on a sliding scale from 85,000 to 100,000 cfs. When forecast is greater than 20 Maf, then the mid-April through June 20 objective is 100,000 cfs. For summer flow objectives (21 June through August), when the forecast is less than 16 Maf, the flow target is 50,000 cfs. For summer, when the forecast is 16 to 28 Maf, objectives range from 50,000 to 55,000 cfs. For summer when the forecast is greater than 28 Maf, flow objectives are 55,000 cfs.
- **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 (191.0 ksfd).
- Lower Snake projects will be **operated at MOP** in accordance with the COE data submittal and the 1995 BiOp. As identified in the BiOp, USACE 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 at 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 PNCA OY99 planning.

**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 | 10 kcfs |
| **Wanapum** | 4.0 | 60.0 | 60.0 | 47.5 | 35.0 | 25.0 | 25.0 | 10 kcfs |
| **Priest Rapids** | 4.7 | 70.0 | 70.0 | 52.5 | 35.0 | 35.0 | 35.0 | 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 |

- **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 USACE. 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.

## Regulated Hydroelectric Projects and Control Points

WHITE RIVER

TIMOTHY

CLACKAMAS [3]

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

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

# 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

# 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 |

## VARIABLE DRAFT LIMITS (BiOp) IN ELEVATION

| | HUNGRY HORSE | | | | GRAND COULEE | | |
|---|---|---|---|---|---|---|---|
| | JAN | FEB | MAR | | JAN | FEB | MAR |
| | -------------- feet elevation ---------------- | | | | -------------- feet elevation ---------------- | | |
| 1929 | 3533.1 | 3528.8 | 3525.3 | | 1273.2 | 1276.6 | 1285.2 |
| 1930 | 3543.9 | 3540.0 | 3536.2 | | 1290.0 | 1285.0 | 1290.0 |
| 1931 | 3540.5 | 3537.0 | 3534.1 | | 1288.6 | 1283.8 | 1289.3 |
| 1932 | 3508.9 | 3505.1 | 3507.8 | | 1225.0 | 1225.6 | 1243.8 |
| 1933 | 3485.0 | 3478.8 | 3473.7 | | 1225.0 | 1225.0 | 1236.6 |
| 1934 | 3519.9 | 3520.8 | 3523.3 | | 1225.0 | 1248.6 | 1260.6 |
| 1935 | 3520.5 | 3519.4 | 3516.4 | | 1225.0 | 1254.6 | 1268.7 |
| 1936 | 3529.6 | 3524.3 | 3520.2 | | 1244.0 | 1249.1 | 1253.7 |
| 1937 | 3539.3 | 3533.9 | 3528.6 | | 1264.7 | 1281.4 | 1287.0 |
| 1938 | 3528.9 | 3524.9 | 3522.0 | | 1225.0 | 1225.0 | 1239.2 |
| 1939 | 3525.6 | 3520.3 | 3518.4 | | 1240.9 | 1272.3 | 1288.5 |
| 1940 | 3544.3 | 3539.9 | 3537.5 | | 1285.9 | 1289.5 | 1290.0 |
| 1941 | 3560.0 | 3559.7 | 3556.4 | | 1275.9 | 1290.0 | 1290.0 |
| 1942 | 3534.1 | 3531.0 | 3527.0 | | 1252.8 | 1273.7 | 1272.9 |
| 1943 | 3497.4 | 3494.3 | 3491.4 | | 1225.0 | 1250.7 | 1252.3 |
| 1944 | 3554.8 | 3550.0 | 3545.4 | | 1276.2 | 1272.9 | 1287.8 |
| 1945 | 3529.1 | 3524.7 | 3520.5 | | 1270.4 | 1266.9 | 1275.9 |
| 1946 | 3518.2 | 3514.2 | 3512.6 | | 1225.0 | 1225.0 | 1240.0 |
| 1947 | 3502.5 | 3499.2 | 3498.5 | | 1225.0 | 1225.0 | 1235.0 |
| 1948 | 3501.7 | 3496.7 | 3492.0 | | 1225.0 | 1225.0 | 1225.4 |
| 1949 | 3528.8 | 3524.0 | 3519.8 | | 1225.0 | 1231.5 | 1249.9 |
| 1950 | 3474.4 | 3470.0 | 3468.0 | | 1225.0 | 1225.0 | 1243.1 |
| 1951 | 3498.1 | 3500.0 | 3498.8 | | 1225.0 | 1225.0 | 1239.8 |
| 1952 | 3527.8 | 3524.1 | 3520.3 | | 1225.0 | 1225.0 | 1241.4 |
| 1953 | 3508.8 | 3507.0 | 3503.6 | | 1225.0 | 1225.0 | 1241.7 |
| 1954 | 3483.1 | 3477.9 | 3473.7 | | 1225.0 | 1225.0 | 1231.1 |
| 1955 | 3516.3 | 3512.1 | 3507.8 | | 1238.0 | 1245.9 | 1236.6 |
| 1956 | 3503.3 | 3498.5 | 3494.5 | | 1225.0 | 1225.0 | 1227.5 |
| 1957 | 3522.5 | 3518.3 | 3515.1 | | 1225.0 | 1225.0 | 1236.6 |
| 1958 | 3523.3 | 3518.8 | 3515.6 | | 1225.0 | 1225.0 | 1243.5 |
| 1959 | 3470.1 | 3466.9 | 3463.5 | | 1225.0 | 1225.0 | 1230.7 |
| 1960 | 3515.0 | 3512.2 | 3513.8 | | 1225.0 | 1250.0 | 1259.8 |
| 1961 | 3508.5 | 3506.0 | 3504.8 | | 1225.0 | 1225.0 | 1239.8 |
| 1962 | 3514.4 | 3510.9 | 3506.7 | | 1225.0 | 1240.5 | 1250.5 |
| 1963 | 3527.5 | 3527.8 | 3526.6 | | 1230.6 | 1261.8 | 1280.1 |
| 1964 | 3496.3 | 3490.0 | 3483.7 | | 1225.0 | 1231.9 | 1246.4 |
| 1965 | 3491.4 | 3487.9 | 3482.9 | | 1225.0 | 1225.0 | 1242.4 |
| 1966 | 3524.5 | 3520.2 | 3517.0 | | 1225.0 | 1271.3 | 1284.4 |
| 1967 | 3490.0 | 3487.4 | 3483.4 | | 1225.0 | 1225.0 | 1230.7 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1968 | 3509.9 | 3507.0 | 3508.6 | | 1236.5 | 1265.1 | 1276.7 |
| 1969 | 3525.2 | 3521.6 | 3518.0 | | 1225.0 | 1236.2 | 1250.1 |
| 1970 | 3509.9 | 3505.0 | 3500.0 | | 1243.8 | 1255.3 | 1262.5 |
| 1971 | 3480.4 | 3482.5 | 3479.7 | | 1225.0 | 1225.0 | 1229.4 |
| 1972 | 3476.5 | 3470.2 | 3473.6 | | 1225.0 | 1225.0 | 1225.0 |
| 1973 | 3538.9 | 3535.5 | 3531.8 | | 1259.9 | 1282.9 | 1288.5 |
| 1974 | 3468.6 | 3468.1 | 3467.0 | | 1225.0 | 1225.0 | 1225.0 |
| 1975 | 3497.1 | 3491.4 | 3485.7 | | 1225.0 | 1225.0 | 1244.3 |
| 1976 | 3504.2 | 3500.7 | 3496.5 | | 1225.0 | 1230.7 | 1251.3 |
| 1977 | 3558.0 | 3553.9 | 3549.6 | | 1262.0 | 1278.6 | 1288.7 |
| 1978 | 3511.0 | 3506.0 | 3503.7 | | 1225.0 | 1226.4 | 1252.8 |
| 1979 | 3519.9 | 3515.2 | 3512.9 | | 1243.7 | 1270.6 | 1282.4 |
| 1980 | 3533.6 | 3528.4 | 3524.0 | | 1225.0 | 1245.3 | 1262.9 |
| 1981 | 3508.7 | 3507.9 | 3508.4 | | 1225.0 | 1226.5 | 1251.7 |
| 1982 | 3491.2 | 3489.1 | 3487.8 | | 1225.0 | 1225.0 | 1237.7 |
| 1983 | 3523.8 | 3520.6 | 3520.4 | | 1225.0 | 1225.0 | 1237.9 |
| 1984 | 3525.9 | 3524.1 | 3522.5 | | 1225.0 | 1225.0 | 1236.8 |
| 1985 | 3518.7 | 3514.4 | 3510.3 | | 1225.0 | 1260.3 | 1272.9 |
| 1986 | 3526.7 | 3524.8 | 3527.3 | | 1225.0 | 1251.6 | 1261.2 |
| 1987 | 3549.7 | 3545.6 | 3545.8 | | 1246.3 | 1275.7 | 1290.0 |
| 1988 | 3547.3 | 3542.1 | 3538.3 | | 1266.5 | 1281.1 | 1290.0 |