US Army Corps of Engineers®
Portland District

WILLAMETTE VALLEY SYSTEM OPERATIONS AND MAINTENANCE

FINAL ENVIRONMENTAL IMPACT STATEMENT

APPENDIX G: POWER GENERATION AND TRANSMISSION

APPENDIX PREPARED BY
BONNEVILLE POWER ADMINISTRATION,
COOPERATING AGENCY

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ACRONYMS

ALT	Alternative
aMW	Average **M**ega**w**atts
Bonneville	Bonneville Power Administration
CCS	Cross Cascades South
CFS	Cubic feet per second
CRS	Columbia River System
CRSO	Columbia River System Operations
CWY	Critical Water Year
PEIS	Draft Environmental Impact Statement
EIS	Environmental Impact Statement
FCRPS	Federal Columbia River Power System
GEN	Generation
GENESYS	GENeration Evaluation SYStem
HYDSIM	HYDro System SIMulation
IOU	Investor-Owned Utilities
IPR	Integrated Program Review
LCOG	Levelized Cost of Generation
LOLP	Loss of Load Probability
LT ATC	Long Term Available Transfer Capability
LTF	Long Term Firm
Mid-C	Mid-Columbia
MW	Megawatt
MWh	Megawatt hour
NAA	No Action Alternative
NPV	Net Present Value
NW Council	Northwest Power and Conservation Council
O&M	Operations and Maintenance
PA	Preferred Alternative
PF	Priority Firm Power
PNW	Pacific Northwest
PUD	Public utility districts
ResSim	Reservoir System Simulation
RME	Research, Monitoring, and Evaluation
SAMP	Strategic Asset Management Plan
SOA	South of Allston
USACE	U.S. Army Corps of Engineers
WVS	Willamette Valley System

THE POWER GENERATION AND TRANSMISSION APPENDIX
HAS BEEN REVISED FROM THE DEIS
INSERTION OF LARGE TEXT IS IDENTIFIED; MINOR EDITS ARE NOT DENOTED

Summary of changes from the DEIS:

- **DEIS Alternative 5 data have been updated.**
- **The term "Near-term Operations" has been changed to "Interim Operations" throughout the EIS. Additional information has been added to several sections of this appendix to further clarify anticipated effects under Interim Operations. Tables and figures have been formatted for consistency and for clarifications.**

1. INTRODUCTION

The Willamette Basin contains several Federal and non-Federal hydroelectric power-generating facilities used to generate electrical energy for local and regional consumption, as well as high-voltage transmission lines and other facilities that move this energy from the generating facilities to local and regional loads.

Regarding Federal hydropower generation, the Flood Control Act of 1948 (Pub. L. No. 80-858, 62 Stat. 1175) modified the Flood Control Act of 1938 to provide for the installation of hydroelectric power-generating facilities at eight U.S. Army Corps of Engineers (USACE) multipurpose projects throughout the Willamette Basin: Detroit, Green Peter, Lookout Point, Cougar, Hills Creek, Big Cliff, Foster, and Dexter dams. These are a subset of the Federal Columbia River Power System (FCRPS) projects. The USACE dictates the parameters for dam operations to meet their statutory requirements, and power generation is subsequently scheduled within these parameters. The Cougar, Hills Creek, Big Cliff, Foster, and Dexter projects run a flat generation schedule each day based on the water available, and the generation schedule is determined solely by USACE. For the Detroit, Green Peter, and Lookout Point projects, Bonneville is provided an opportunity to optimize the daily timing of power generation after USACE determines their statutory requirement needs for other project purposes, such as flood control, and fish and water quality operations; and identifies how many hours of generation would be available within a day, as well as any constraints (e.g., cannot be more than 10 continuous hours without generation).

Bonneville is a Federal power marketing administration designated by statute to sell power and transmission services throughout the Pacific Northwest region. Bonneville sells electric power from FCRPS projects, operated and maintained by other Federal agencies (i.e., USACE or the U.S. Bureau of Reclamation (Reclamation)), to its regional firm power customers (wholesale power customers) across the Pacific Northwest, including municipalities, public utility districts (PUDs), cooperatives, Federal agencies, investor-owned utilities (IOUs), and one direct service industry customer. These wholesale power customers, in turn, serve residential, commercial, and industrial retail customers (i.e., “end users”).

Bonneville also operates and maintains about 15,000 circuit miles of the high-voltage transmission system within the Pacific Northwest region (Bonneville 2024). This system integrates and transmits electric power within the Pacific Northwest region and interconnects with external transmission systems throughout the western United States and parts of Canada and Mexico. Separate from its power sales, Bonneville sells transmission services (for the delivery of electricity from generating resources to end users) and associated ancillary services (for maintaining transmission system reliability) to regional firm power customers, independent power producers, and power marketers.

1.1 Framework for the Power and Transmission Analysis

This appendix details Bonneville’s analysis, in coordination with USACE, of the effects of the Willamette Valley System (WVS) Operations and Maintenance (O&M) Final Environmental

Impact Statement Alternatives (Alternatives 1, 2A, 2B, 3A, 3B, 4, 5 and Preferred Alternative [PA]; hereinafter referred to collectively as Action Alternatives) on Federal power and transmission resources, including the models, methods, and data sources employed, and a stepwise presentation of the results for each alternative. An additional analysis for the Interim Operations was also included in this appendix and study.

While not modeled as part of the Action Alternatives, the Interim Operations were modeled as a stand-alone analysis and are included in subsequent sections for further context on the current operations in the Willamette Valley and in consideration of the ongoing impacts these operations have in parallel with the implementation of the Alternatives. Please refer to Chapter 2 of the EIS for additional detail on Interim Operations. Figure 1.1-1 presents the framework for the analysis.

The power and transmission analysis does not model the effects of implementing the Biological Opinion Reasonable and Prudent Alternative (RPA) because they would not substantially differ from those presented in the EIS for Interim Operations. RPA measures mirror expected impacts to interim generation, for example, through drawdowns below the power pool or seasonal fish-passage flows or spill patterns that similarly impact generation. Furthermore, the effects of RPA measures deviate most from interim operations in the driest water years when the ability to generate power is already reduced. Therefore, to address the currently defined RPA-associated effects, the EIS power and transmission analysis qualitatively addresses these effects where appropriate. As discussed in Appendix N, Implementation and Adaptive Management Plan, a long-term flow management plan would be developed through an adaptive management process, which could increase impact the scope of power and transmission impacts as RPA measures are implemented. Power and transmission effects will continue to be monitored during the implementation of the RPA and the need for additional effects analysis under NEPA and other environmental compliance processes will also be evaluated accordingly.

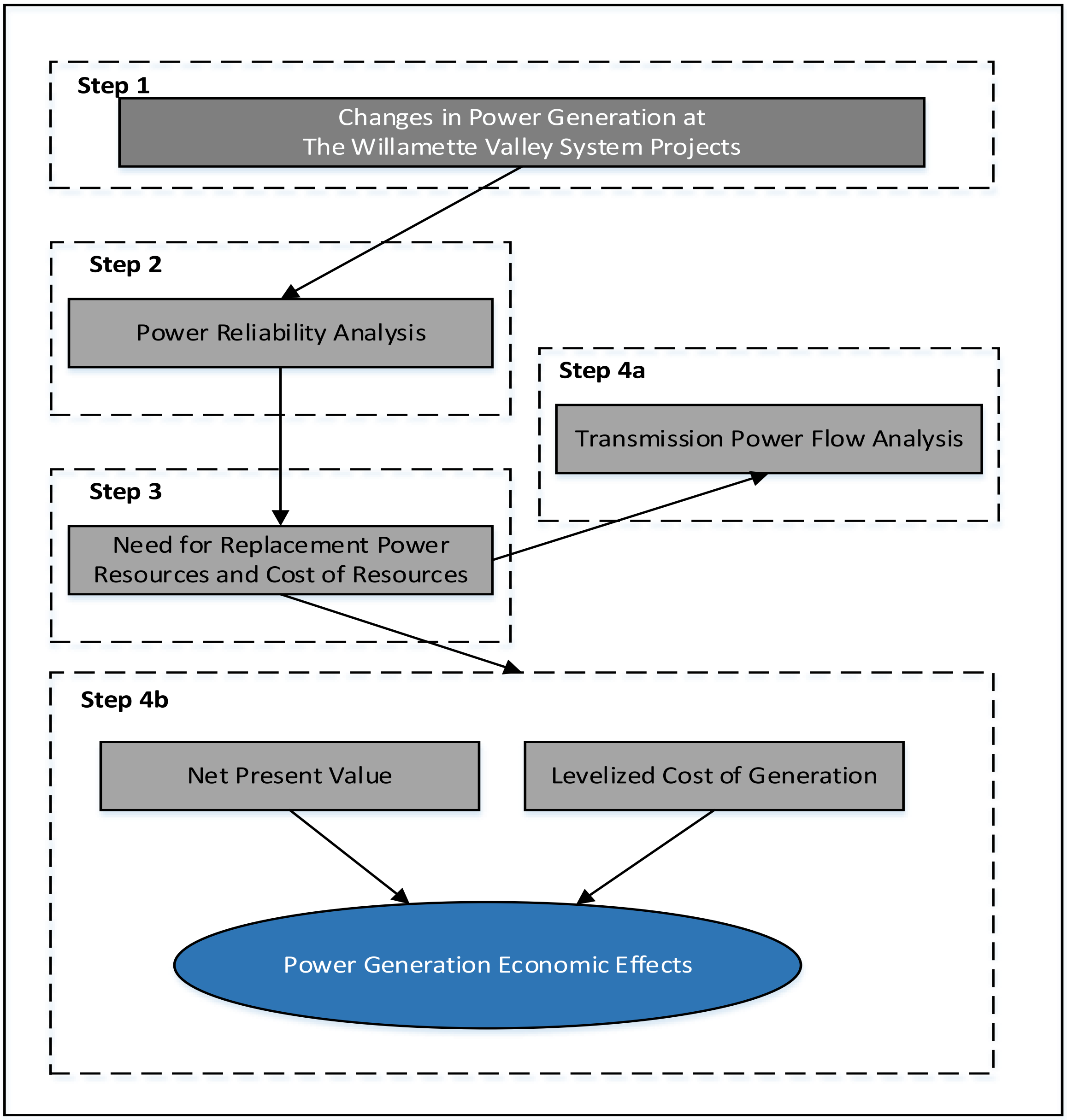

Figure 1.1-1. Analytical Approach for Evaluating Power and Transmission Effects.
Note: Additional power and transmission analysis occurs within each of the step boxes depicted.

Step 1 of the analysis assesses the effects of the alternatives on hydropower generation based on average historical water conditions and for critical water conditions.[1] The amount of power generated by the system under each of the alternatives determines whether additional changes to, or investments in, the system may be required to maintain Bonneville's ability to supply

[1] The "critical water year" or "critical water conditions" represent the historic water year when the capability of the hydro system produces the least amount of dependable generation to serve the least amount of load while considering power and non-power operating constraints.
[2] In the context of power acquired from new resources, "existing" refers to currently operating generating plants or renewables (e.g., wind, solar, etc.) located outside of the Pacific Northwest region.

adequate and reliable power (including energy, capacity, and reactive voltage support during normal generation or in synchronous condenser mode) to its firm power customers under 20-year contracts. Step 2 of the analysis evaluates the extent to which the alternatives would result in the need for Bonneville or other regional entities to acquire power from other resources (e.g., new or existing generating plants, wind, solar, etc.[2]) and construct new transmission infrastructure to replace the lost capability at Federal hydropower projects. To the extent Step 2 identifies a potential need to acquire resources or to build transmission infrastructure, Step 3 would identify potential replacement resources, transmission network upgrades for reactive voltage support, and associated costs.[3] Step 4a, the transmission analysis, estimates the incremental power flow change on Bonneville Transmission Network Paths between the No Action Alternative (NAA) and each of the Action Alternatives during multiple seasons as a result of generation output changes at the Federal WVS projects with hydropower facilities (Detroit, Big Cliff, Cougar, Green Peter, Foster, Hills Creek, Lookout Point, and Dexter dams).

Based on the inclusion of any new capital investments under each of the Action Alternatives, Step 4b of the analysis considers the Net Present Value (NPV) and Levelized Cost of Generation (LCOG) resulting from the increased costs of providing power. The NPV analysis compares the expected revenue produced by each WVS Project with hydropower facilities against its expected costs over a 30-year[4] study period for each of the Action Alternatives. A positive NPV indicates that power generation is economically justified while a negative NPV indicates that the costs of power production outweigh the benefits. The LCOG analysis evaluates the incremental cost of producing power, in $/MWh, for each project over the 30-year study period. This value provides a relative measure of cost-competitiveness when compared to other generating resources or market purchases.

The areas of analysis for the power and transmission resources differ as a function of Bonneville's products and services. Both the power and transmission studies focus on Bonneville's service area (Figure 1.1-2). The Bonneville service area is defined by the Northwest Power Act as the Pacific Northwest, which includes Oregon, Washington, Idaho, the portion of Montana west of the Continental Divide, and the portions of Nevada, Utah, and Wyoming within the Columbia River drainage basin. However, because Bonneville regularly markets its surplus power both within and outside the Pacific Northwest, the power evaluation additionally considers potential effects on power markets within the larger U.S. portion of the Western Interconnection (Figure 1.1-2). The transmission analysis considers potential effects on multiple

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[3] To the extent Step 2 identifies potential needs to acquire power from new resources or construct transmission infrastructure, and if Bonneville proposes to take such action in the future, Bonneville would do so consistent with the Northwest Power Act and would complete additional site-specific planning and analysis in compliance with environmental laws, including the National Environmental Policy Act (NEPA).

[4] Bonneville's standard power generation economic analysis timeframe is 50 years. For consistency with other analyses in the EIS, a 30-year timeframe was used instead.

"paths," or routes, over which power flowing from one point to another is monitored and managed (Figure 1.1-3).

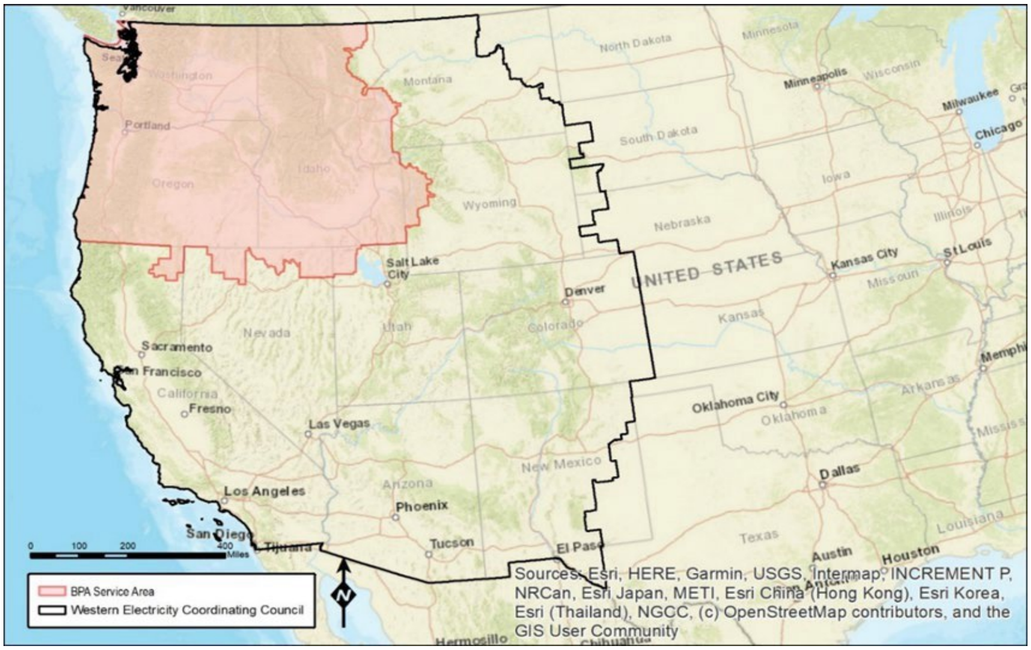

Figure 1.1-2. Bonneville Service Area and U.S. Portion of the Western Interconnection.

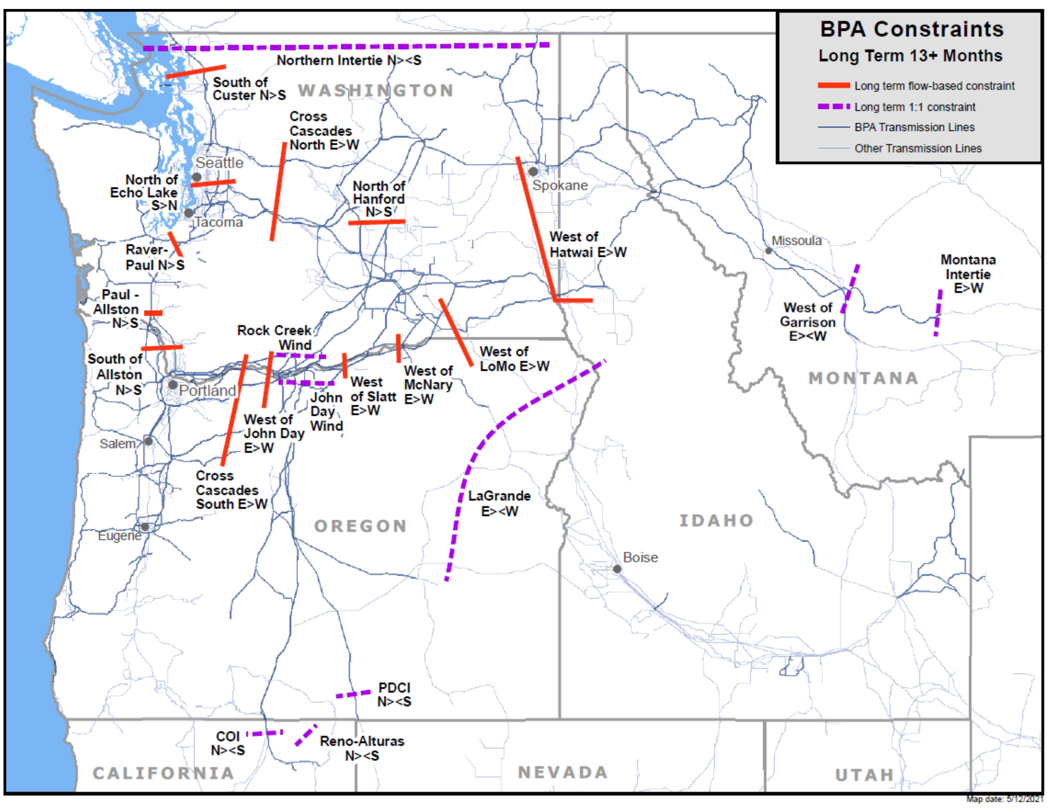

Figure 1.1-3. Northwest Transmission Paths.

Note: Red and purple dashed lines denote defined paths and interties (locations where power flows are monitored and analyzed).
Source: Bonneville (2021).

1.2 Organization of the Appendix

This appendix is organized as follows:

Section 2 – Changes in Hydropower Generation (in aMW[5]). Section 2 focuses on Step 1 (Figure 1.1-1), describing the approach to modeling changes in power generation at the eight WVS projects with hydropower facilities.[6]

Section 3 – Regional Power Supply and Replacement Resources. Section 3 focuses on Steps 2 and 3 (Figure 1.1-1), describing the approach to modeling the impacts of changes in power generation at the WVS projects on power supply (expressed in terms of LOLP), and, if needed, identifying any replacement resources and associated costs for maintaining an adequate and reliable supply of electricity.[7]

Section 4 – Transmission Paths Incremental Analysis. Section 4 describes Step 4a (Figure 1.1-1), linking changes in how and where power is generated to effects on the transmission system reliability.

Section 5 – Economic Viability of Power Generation. Section 5 describes Step 4b (Figure 1.1-1), evaluating how changes in power generation and costs affect the economic viability of WVS projects.

1.3 Summary of Results for Power and Transmission Analysis

Table 1.3-1 on pages G-10 and G-11 presents the summary of results for all Action Alternatives as well as for Interim Operations. The following paragraphs describe results by topic for the Action Alternatives relative to the NAA.

1.3.1 Hydropower Generation

Under the NAA, annual average hydropower generation from the WVS projects was calculated to be 171 aMW[8] (roughly the amount of power used by 136,416 Northwest homes or used by residential customers in a city slightly more populated than Gresham, Oregon). Under Alternative 1 and 4, annual average hydropower generation from the WVS projects increased by 8 and 1.0 aMW, respectively, which reflect slight to indistinguishable increases

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[5] The average electric power created from an energy source in megawatts (MW).
[6] The eight WVS projects with hydropower facilities are Cougar, Detroit, Big Cliff, Lookout Point, Dexter, Hills Creek, Green Peter, and Foster.
[7] Loss of Load Probability under the No Action Alternative is 6.5 percent. The NW Council target for LOLP is 5 percent. *See NW* Council Document Number 2011-14, Page 4, available at: https://www.nwcouncil.org/sites/default/files/2011_14_1.pdf.
[8] An average megawatt is 1 million watts delivered continuously 24 hours a day for 1 year.

(approximately 4.7 and 0.6 percent, respectively) relative to the NAA.. Under Alternative 2A, annual average hydropower generation from the WVS projects decreased by approximately 4 aMW (-2.3 percent) relative to the NAA. Under Alternative 2B, annual average hydropower generation from the WVS projects decreased by approximately 18 aMW, or an approximate 10.6 percent decrease relative to the NAA. This annual average reduction reflects monthly reductions from November through May counterbalanced by increases in power from June through October.

The annual average hydropower generation from the WVS projects under Alternative 3A and Alternative 3B decreased by 87 and 79 aMW, respectively, which are approximately 47.9 and 45.8 percent decreases relative to the NAA. These reductions reflect the numerous operational changes included in Alternative 3A and Alternative 3B resulting in reservoir elevations frequently being below the power pool; thereby, precluding hydropower generation for extended periods. Under Interim Operations, annual average hydropower generation from the WVS projects would decrease by approximately 52 aMW, an approximate 29.8 percent decrease relative to the NAA.

1.3.2 Regional Power Supply – Loss of Load Probability (LOLP)[9] and Replacement Resources

The best available regional hydroregulation data was used for this analysis, which includes Interim Operations hydroregulation data for the Willamette Valley System (WVS) projects generated by the USACE (see Appendix B), combined with hydroregulation data for all other FCRPS projects sourced from the Columbia River System Operations (CRSO) EIS Preferred Alternative (USACE et al. 2020). Given the WVS projects represent a small subset of the FCRPS projects, the resulting NAA LOLP of 6.5 percent was indistinguishable from the CRSO EIS Preferred Alternative LOLP of 6.4 percent (i.e., within the +/- 1 percent range of modeling accuracy).

Without replacement resources, regional LOLP would negligibly increase under Alternatives 2B, 3A and 3B, and 5 (+0.1 to +0.5 percentage points for each); would negligibly decrease under Alternative 1 (-0.1 percentage points), and would not change under Alternative 2A and Alternative 4 relative to the NAA. Since the LOLPs for each of the Action Alternatives are not materially different than the NAA (i.e., differences are within the +/- 1 percent range of modeling accuracy), the Action Alternatives would maintain essentially the same level of regional power system reliability as the NAA; therefore, replacement resources to return the LOLP to the NAA level would not be needed for any of the Action Alternatives.

[9] LOLP is expressed as a percentage that reflects the probability that the system will not be able to meet the demand for electricity in a particular year. Higher LOLPs reflect the increased likelihood that the power system would be unable to meet demand, and therefore, will result in power shortages or blackouts. A high LOLP is an indication of a less reliable power system. A low LOLP reflects a low likelihood that the power system will experience a power shortage. The LOLP is a measure of the frequency of outages but not a measure of their duration or magnitude.

1.3.3 Transmission Paths Incremental Analysis

The transmission flowgate incremental analysis identifies the potential changes in power flows that may occur under each Action Alternative. Overall, results indicate that a reduction of the Willamette Valley System power generation and the location of replacement power generation either at Upper Columbia or Lower Snake generation facilities can decrease the transmission inventory available for commercial sales on one or more constrained network flowgates. Constrained network flowgates for commercial planning have historically included South of Allston, Raver-Paul, North of Echo Lake, Cross Cascades South, and Cross Cascades North. Constraint definitions and total transfer capabilities can be subjected to change based on the future state of the transmission system and the evolving external market landscape.

1.3.4 Economic Viability of Power Generation

This analysis identifies the potential changes in the WVS projects' NPV and LCOG that may occur under each of the Action Alternatives. Overall, results indicate that power generation reductions and costs of structural measures under the Action Alternatives would result in large reductions in NPV and increases in the LCOG compared to the NAA. The NAA has a positive NPV of $356 million. All of the Action Alternatives result in a negative median NPV for all WVS projects combined ranging from approximately -$771 million (Alternative 3B) to -$1.4 billion (Alternative 1),[10] which represent -$1.13 billion and -$1.76 billion in reductions relative to the NAA, respectively. Under the Action Alternatives, LCOG is expected to increase from $30.03/MWh in the NAA to between $65.74/MWh (Alternative 2A) to $91.48/MWh (Alternative 3A). Interim Operations also result in a negative NPV of -$213 million, representing a -$569 million change in NPV relative to the NAA and a $11.65/MWh increase in LCOG from $30.03/MWh to $48.95/MWh.

[10] Bonneville's share of basin-wide costs (e.g., RME) were not included in this analysis. With inclusion of those costs, the Net Present Value would be incrementally lower, and the Levelized Costs of Generation would be incrementally higher. Additionally, structural cost estimates used in the analysis of Action Alternatives were at a conceptual design level with a 50 percent contingency. For other projects of similar size and complexity, the conceptual design cost estimates increased by 137 percent to 215 percent upon completion of the detailed design report. Post-construction, the complexity of these systems has typically resulted in further costs to improve performance. Higher implementation costs than currently estimated would result in additional reductions of the Net Present Value and increases in the levelized costs of generation.

Table 1.3-1. Summary of Hydropower and Transmission Effects for All WVS PEIS Alternatives[6/]

Effect[1/]	No Action Alternative (NAA)[1/]	ALT 1 Relative to NAA	ALT 2A Relative to NAA	ALT 2B Relative to NAA	ALT 3A Relative to NAA	ALT 3B Relative to NAA	ALT 4 Relative to NAA	Interim Operations Relative to NAA	Alternative 5 Relative to NAA
WVS Hydropower Generation (aMW)	171.3	+8	-4	-18	-87	-79	+1.0	-52	-18
Loss of Load Probability (LOLP; percent)	6.5	-0.1	0	+0.1	+0.5	+0.5	0	+0.3	+0.1
Replacement Resources/Costs to return LOLP to NAA level	——[2/]	NA[3/]	NA[3/]	NA[3/]	NA[3/]	NA[3/]	NA[3/]	NA[3/]	NA[3/]
Transmission Flow Paths (seasonal MW changes on currently congested paths Cross Cascades South [CCS] and South of Allston [SOA])	Winter:6475.5 CCS; 1183 SOA Spring:4100.5 CCS;732.1 SOA Summer: 5862.9 CCS;2525.1 SOA	All seasons: <+10 CCS & SOA	Winter:+18.4 CCS; +6.9 SOA Spring:+61.3 CCS; +11.8 SOA Summer: <+10 CCS & SOA	Winter:+21.9 CCS; +8.3 SOA Spring:+25.1 CCS; 5.1 SOA Summer: <+10 CCS & SOA	Winter:+37.2 CCS; +13.6 SOA Spring:+113.7 CCS;+22.3 SOA Summer:+28.3 CCS	Winter:+41.4 CCS;+15.2 SOA Spring:+94.8 CCS; +18.7 SOA Summer:+25.6 CCS	Winter/Su: <+10 CCS & SOA Spring: +15 CCS; +3.2 SOA	Winter:+47.0 CCS; +17.0 SOA Spring: +59.8 CCS; +11.4 SOA Summer: <+10 CCS & SOA	Winter:+21.9 CCS; +8.3 SOA Spring:+25.1 CCS; 5.1 SOA Summer: <+10 CCS & SOA
Transmission Reliability	Same/similar to affected environment	No change	No change	No regional change/locally comprised Blue River[4/]	No regional change/locally comprised Oakridge & Blue River[4/]	No regional change/locally comprised Oakridge & Blue River[4/]	No change	No regional change/locally comprised Blue River[4/]	No regional change/locally comprised Blue River[4/]
Net Present Value[5/]	$356M	-$1.76B	-$1.25B	-$1.33B	-$1.15B	-$1.13B	-$1.61B	-$569M	-$1.34B
Levelized Cost of Generation ($/MWh)[5/]	$30.03	+$48.63	+$35.71	+$40.67	+$61.45	+$53.81	+$46.31	+$18.92	+$41.19
WVS Hydropower Generation – Including Transition[†] from Interim Operations (aMW)	119 to 171	119 to 179	119 to 167	119 to 153	119 to 84	119 to 92	119 to 172	119	119 to 153

Notes: The estimated Loss of Load Probability (LOLP) effects rely on the best available information regarding planned coal plant retirements as of 2017.
1/ The analysis of the NAA for these effect categories provides a baseline against which the Action Alternatives (labeled ALTs" in the table above) are compared. Thus, the NAA results presented in this table describe the baseline magnitude of hydropower and transmission values and the Alternative 1 through Alternative 5 describe the change relative to No Action.

2/ A "——" indicates an effect category that is not relevant to the No Action Alternative because it only occurs as a result of implementing the Action Alternatives (e.g., the need for new generation and transmission infrastructure and associated costs).

3/ The LOLP determined to be essentially the same as the NAA (within the +/- 1 percent range of modeling accuracy), so no replacement resources needed to return LOLP to the NAA level.
4/ Deep fall and spring drawdowns would compromise Hills Creek and/or Cougar dams' abilities to operate islanded and serve Oakridge and Blue River communities, respectively, under temporary storm or fire related outage conditions.

5/ Bonneville's share of basin-wide costs (e.g., RME) were not included in this analysis. With inclusion of those costs, the Net Present Value would be incrementally lower and the Levelized Costs of Generation would be incrementally higher. Additionally, structural cost estimates used in the analysis of Action Alternatives were at a conceptual design level with a 50% contingency. For other projects of similar size and complexity, the conceptual design cost estimates increased by 137 percent to 215 percent upon completion of the detailed design report. Post-construction, the complexity of these systems has typically resulted in further costs to improve performance. Higher implementation costs than currently estimated would result in additional reductions of the Net Present Value and increases in the levelized costs of generation. NPV was calculated by BPA and does not use USACE methodologies.

6/ Alternative 5 effects are only inclusive of interim operational measures and do not account for structural measures that have been proposed under the court order (e.g., Dexter Hatchery improvements), nor do they account for operational changes that could occur as a result of structural measure implementation.

[†] Generation ranges reflect Interim Operations transitioning to longer-term operations under the alternatives over time, and as the structural measures under the alternatives would be completed. 119aMW represents generation anticipated under Interim Operations until the completion of structural measures. Duration of the Interim Operations depends on several factors such as funding availability, construction schedules, and achievement of biological objectives.

2. HYDROPOWER GENERATION

This section provides the modeling analysis used to estimate the hydropower generation values (in aMW) resulting from the NAA and several alternatives with comparisons to the NAA. Hydropower generation results were calculated using HYDSIM (**HYD**ro System **SIM**ulator) for the eight WVS projects with hydropower facilities, including: Cougar, Detroit, Big Cliff, Lookout Point, Dexter, Hills Creek, Green Peter, and Foster dams. Two metrics were evaluated specifically for hydropower generation: average generation and critical water year (1937) average generation.

2.1 Hydropower Generation Methodology

Bonneville and USACE collaborated on modeling hydropower generation for the WVS PEIS alternatives. USACE first used ResSim to model reservoir operations for the WVS PEIS alternatives (Appendix B). The resulting ResSim values for reservoir elevations, stream flows, and project spills were used as inputs for many different analyses performed for the WVS PEIS. Because ResSim does not include power drivers in operations and ResSim outputs did not provide hydropower production values for the alternatives, Bonneville produced the hydropower generation results using HYDSIM as described in Section 2.1.1 below. The reservoir and streamflow conditions for each alternative over the 73-year study period in HYDSIM (Water Years 1935/36 through 2007/08) and the corresponding period in ResSim studies were closely coordinated with USACE to minimize differences.

2.1.1 HYDSIM

HYDSIM has been in use at Bonneville for decades and is a well-calibrated hydropower generation model. HYDSIM is a monthly model, where April and August are split into half-months (e.g., April I and April II) giving 14 HYDSIM periods in each water year. The model has been used for years for hydropower planning at Bonneville and for Treaty coordination with Canada and regional utilities. Project inflows, outflows, powerhouse flows, and spills calculated by HYDSIM are period averages. Reservoir elevations and storage contents calculated by HYDSIM are end-of-period. Key study inputs include the measures listed in the Final EIS, Chapter 2. Water Years 1935/36 through 2007/08 from the 2010 modified flows dataset (BPA 2011) described in Appendix B were used as the baseline hydrology. Attachment 1 provides additional information regarding the HYDSIM model.

Bonneville used the HYDSIM generation output to estimate and assess the impacts on two metrics, the average generation and critical water year generation, for each of the alternatives. These are standard metrics Bonneville uses in several types of studies involving the FCRPS, including Bonneville rate cases, system reliability studies, CRT planning studies, and planning studies such as the WVS EIS, and are as follows:

Average generation (aMW): The average electric power created from an energy source in megawatts (MW). In this appendix, the average generation is reported either by year or by 14-

period averages wherein April and August are split into two periods. It is calculated by HYDSIM as the annual average or the 14-period average for the 73 water-years studied.

Critical water-year average generation: The generation for water year 1937 (October 1, 1936 – September 30, 1937) is calculated in HYDSIM. This dry water year is one of the lowest average Columbia River System (CRS) power generation of all years in the 73-year study period and the least amount of load can be served by the hydro system during this period. Production of this amount of hydropower could reasonably be expected if the 1937 conditions repeated under modern system conditions. It is an important metric in determining the need for additional resources (power) to meet the Administrator's load supply obligations or replace aging and retired generating resources. Bonneville's long-term firm power sales to its regional power customers are tied to this metric.

2.2 Energy Generation Results

Energy generation results for each of the Action Alternatives were produced for the WVS projects with hydropower facilities and the remainder of the FCRPS system was held constant since the operations of the U.S., CRS (Federal), Mid-Columbia, and Canadian systems are not influenced by WVS operations. Generation results for each alternative are driven primarily by storage reservoir objectives for downstream flow measures and specified project operational measures for fish passage. Chapter 2 of the EIS provides details about the measures in the Action Alternatives. This section also compares the energy generation results between the NAA and each Action Alternative and provides explanations for generation changes from the NAA.

2.2.1 WVS Projects Energy Generation Summaries

Energy generation from results of HYDSIM outputs for combined WVS projects are provided for 73-Year Average Generation in Table 2.2-1 and Figure 2.2-1, and for Critical Water Year (1937) Average Generation in Table 2.2-2 and Figure 2.2-2.

Table 2.2-1. WVS Projects 73-Year Average Generation: Differences in Generation (aMW) compared to the NAA1/

	NAA	ALT1	ALT2A	ALT2B	ALT3A	ALT3B	ALT4	Int. Ops	ALT5
Oct	134	39	38	13	-83	-77	26	-5	15.5
Nov	230	46	-13	-41	-182	-187	20	-118	-49.2
Dec	231	-4	-53	-67	-148	-159	-8	-124	-69.5
Jan	235	-5	-30	-36	-60	-68	-7	-76	-37.8
Feb	147	-1	-7	-6	17	38	0	-20	-5.0
Mar	143	-11	-12	-22	-28	-11	-11	-43	-23.3
Apr I	177	-27	-26	-39	-81	-59	-26	-96	-33.8
Apr II	182	-29	-36	-50	-111	-100	-37	-110	-46.2
May	222	-9	-21	-39	-177	-154	-22	-89	-37.8
Jun	162	21	27	7	-119	-106	27	-10	7.3
Jul	106	30	20	9	-53	-44	19	5	8.1
Aug I	114	20	14	5	-56	-54	15	-16	4.7
Aug II	118	17	12	3	-52	-43	13	-18	2.9
Sep	151	-9	15	6	-59	-39	-14	-19	6.3
Annual Average	**171**	**8**	**-4**	**-18**	**-87**	**-79**	**1**	**-52**	**-18.6**

1/ HYDSIM (Hydro System Simulation) uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves. Source: HYDSIM modeling results

Table 2.2-2. WVS Projects Critical Water Year (1937) Average Generation: Differences in Generation (aMW) compared to the NAA1/

	NAA	ALT1	ALT2A	ALT2B	ALT3A	ALT3B	ALT4	Int. Ops.	ALT5
Oct	119	8	17	-6	-83	-74	10	-11	32
Nov	156	52	7	-30	-144	-142	18	-82	-49
Dec	80	-9	-16	-14	-58	-63	-21	-45	-42
Jan	47	-6	-8	-14	-26	-32	-11	-27	-20
Feb	67	-10	-10	-17	-29	-37	-8	-40	-20
Mar	121	-7	-43	-54	-65	-52	-6	-43	-54
Apr I	188	-3	-6	-25	-63	-82	-12	-82	-30
Apr II	227	24	0	-43	-89	-124	0	-140	-44
May	356	5	-26	-50	-289	-251	-31	-145	-53
Jun	264	50	27	8	-197	-180	21	-14	8
Jul	111	20	25	12	-31	-23	23	20	14
Aug I	115	17	7	8	-46	-39	8	-8	1
Aug II	124	10	5	3	-58	-33	2	-22	2
Sep	155	-12	22	24	-30	-3	-18	4	18
Annual Average	**150**	**10**	**0**	**-14**	**-90**	**-83**	**-2**	**-42**	**-17**

1/ HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves. Source: HYDSIM modeling results.

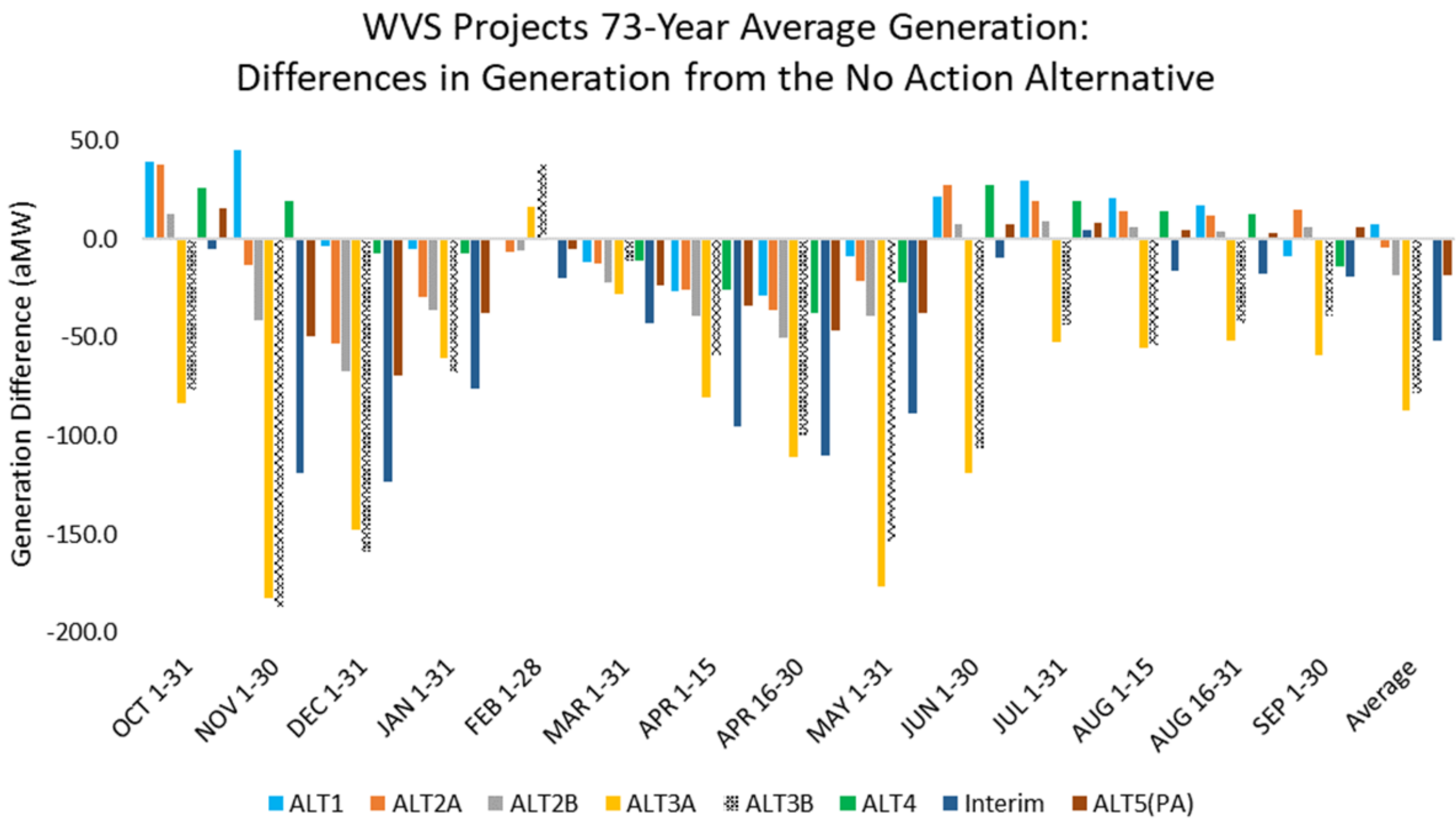

Figure 2.2-1. WVS Projects 73-Year Average Generation: Differences in Generation (aMW) from the No Action Alternative

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.

Source: HYDSIM modeling results.

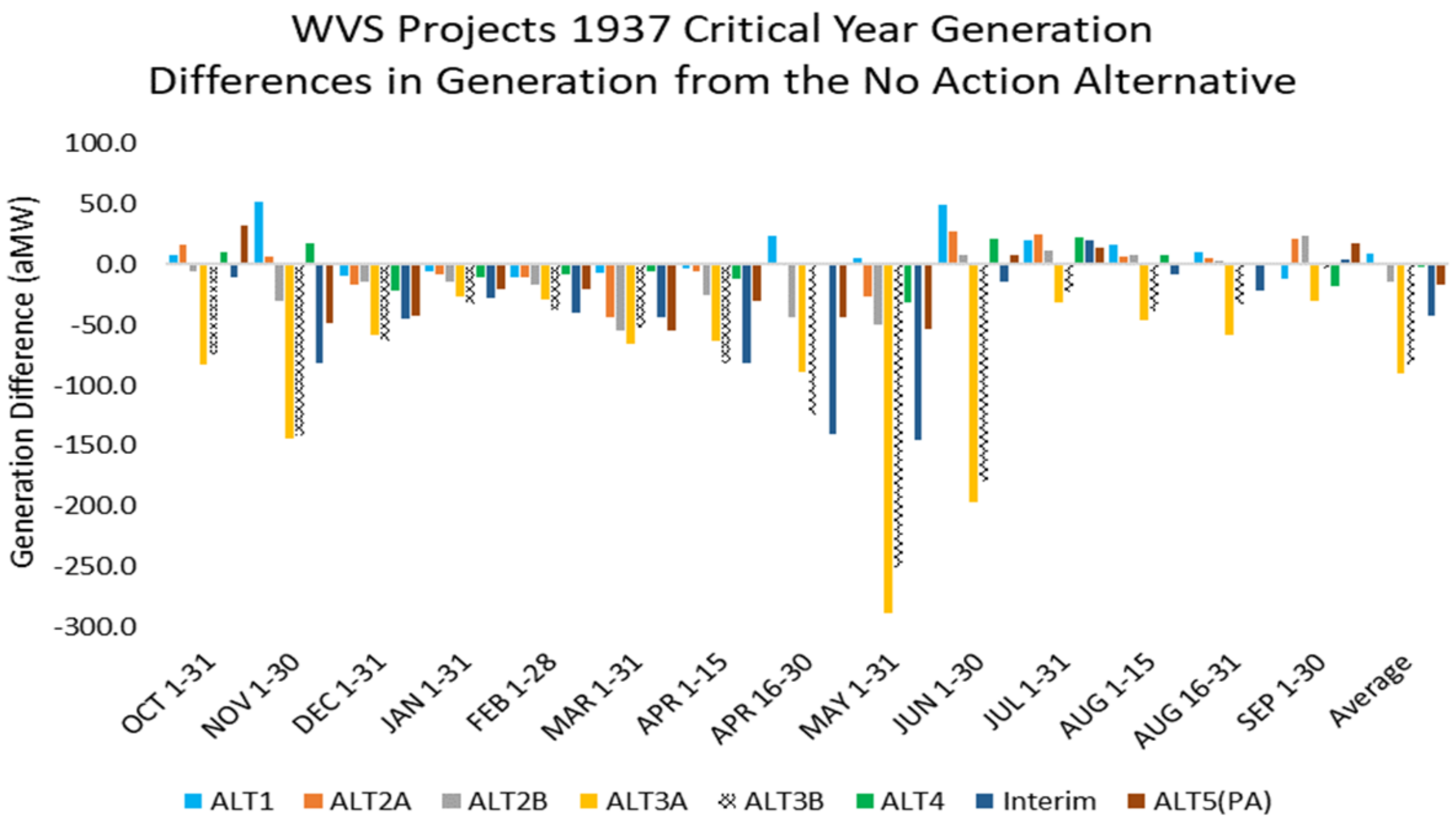

Figure 2.2-2. WVS Projects Critical Water Year (1937) Average Generation: Differences in Generation (aMW) from the No Action Alternative

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.

Source: HYDSIM modeling results.

2.2.2 WVS Projects Energy Generation (aMW): Alternative Comparisons to NAA

The following energy generation comparisons of Action Alternatives with the NAA are provided for the WVS projects with hydropower facilities (i.e., Dexter, Lookout Point, Hills Creek, Foster, Green Peter, Cougar, Big Cliff, and Detroit dams). Detailed information for individual project differences is provided in Attachment 2.

Energy: No Action Alternative

As noted above, Table 2.2-1 and Table 2.2-2 depict the 73-Year Average Generation and Critical Water Year (1937) Average Generation of the combined WVS projects under the NAA, respectively. The annual average generation for the 73-year period is approximately 21 aMW higher than the critical water year (171 aMW versus 150 aMW). Generation varies seasonally with the lowest occurring in the months of July and August (106 to 118 aMW) over the 73-year period, and in December through February (47 to 80 aMW) during the critical water year. Highest generation occurs in November through January and again in May (222 to 235 aMW) over the 73-year period and from the latter half of April through June (227 to 356 aMW) during the critical water year.

Energy: Alternative 1 compared to NAA

Table 2.2-3 depicts the differences between Alternative 1 and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation of the combined WVS projects. Positive differences indicate an increase, and negative differences indicate a decrease in average generation (aMW) from the NAA.

Figure 2.2-3 and Figure 2.2-4 illustrate the differences in generation of individual WVS projects between Alternative 1 and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation, respectively. Individual project blocks indicate the amount of change in each project's monthly average generation (aMW) from the NAA. Project blocks above the zero line indicate a project under Alternative 1 measures generated more than the NAA; blocks below the zero line indicate less generation under Alternative 1 measures than the NAA. The total line indicates the difference in monthly average generation (aMW) for all WVS projects combined from the NAA.

Alternative 1: 73-YEAR AVERAGE GENERATION

Table 2.2-3 indicates an average annual increase of 8 aMW for the WVS projects combined under Alternative 1 compared to the NAA. Differences in the 73-year Average Generation of the WVS projects between Alternative 1 and the NAA primarily resulted from the following:

OCT - NOV: Higher average generation under Alternative 1 during this period was largely driven by increases in outflows through turbines at Detroit and Green Peter dams. In Alternative 1, temperature control towers at Detroit and Green Peter dams replace operational spills for temperature management, which allows for increased flows through the turbines. Increased generation at these locations was somewhat offset by decreased generation at Lookout Point Dam.

Table 2.2-3. WVS Projects 73-Year Average Generation and Critical Water Year (CWY, 1937) Average Generation (aMW): Alternative 1 relative to NAA[1/]

	AVG GEN NAA	AVG GEN Alternative 1	AVG GEN Difference	CWY GEN NAA	CWY GEN Alternative 1	CWY GEN Difference
Oct	134	173	39	119	127	8
Nov	230	276	46	156	208	52
Dec	231	227	-4	80	71	-9
Jan	235	230	-5	47	41	-6
Feb	147	146	-1	67	57	-10
Mar	143	132	-11	121	114	-7
Apr I	177	150	-27	188	185	-3
Apr II	182	153	-29	227	251	24
May	222	213	-9	356	361	5
Jun	162	183	21	264	314	50
Jul	106	136	30	111	131	20
Aug I	114	134	20	115	132	17
Aug II	118	135	17	124	134	10
Sep	151	142	-9	155	143	-12
Annual Average[2/]	**171**	**179**	**8**	**150**	**160**	**10**

1/ HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
2/ The Annual Average is a weighted average to account for the different number of days in the 14 periods.
Source: HYDSIM modeling results.

DEC – FEB: Slight reductions in average generation from the NAA during this period can be attributed to increases in spill, which were offset by some increased flows through turbines that moderated the reduction in average generation during this period. At Foster Dam, for example, the spill was typically greater than the change in turbine outflows. Hence, flow offsets helped explain the extent of generation reduction.

MAR – MAY: Reduced average generation under Alternative 1 during these months is primarily driven by reduced generation at Hills Creek (lower flows and higher end elevations result in reduced generation), Cougar, and Lookout Point dams.

JUN – AUG: Higher average generation under Alternative 1 in these months is driven by structural and/or operational changes at Detroit and Lookout Point dams. A temperature tower at Detroit Dam reduces the need for spill and results in increased flows through turbines with concomitant increases in generation. At Lookout Point Dam, increased flows through turbines contribute to increased generation.

SEPT: Reduced average generation under Alternative 1 in September can be attributed to decreased flows at Green Peter and Foster dams resulting in lower generation. These reductions are somewhat offset by increases in generation at Detroit Dam due to decreased spill at this location.

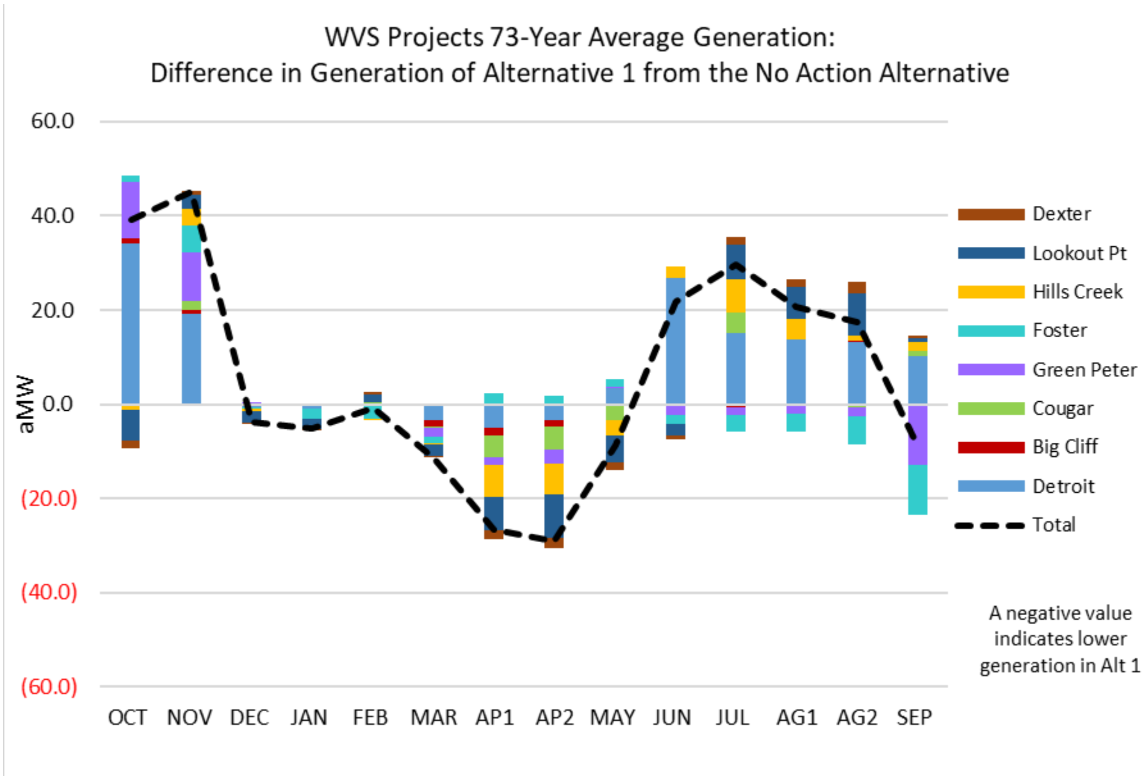

Figure 2.2-3. 73-Year Average Generation: Difference in Generation of Alternative 1 from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
Source: HYDSIM modeling results.

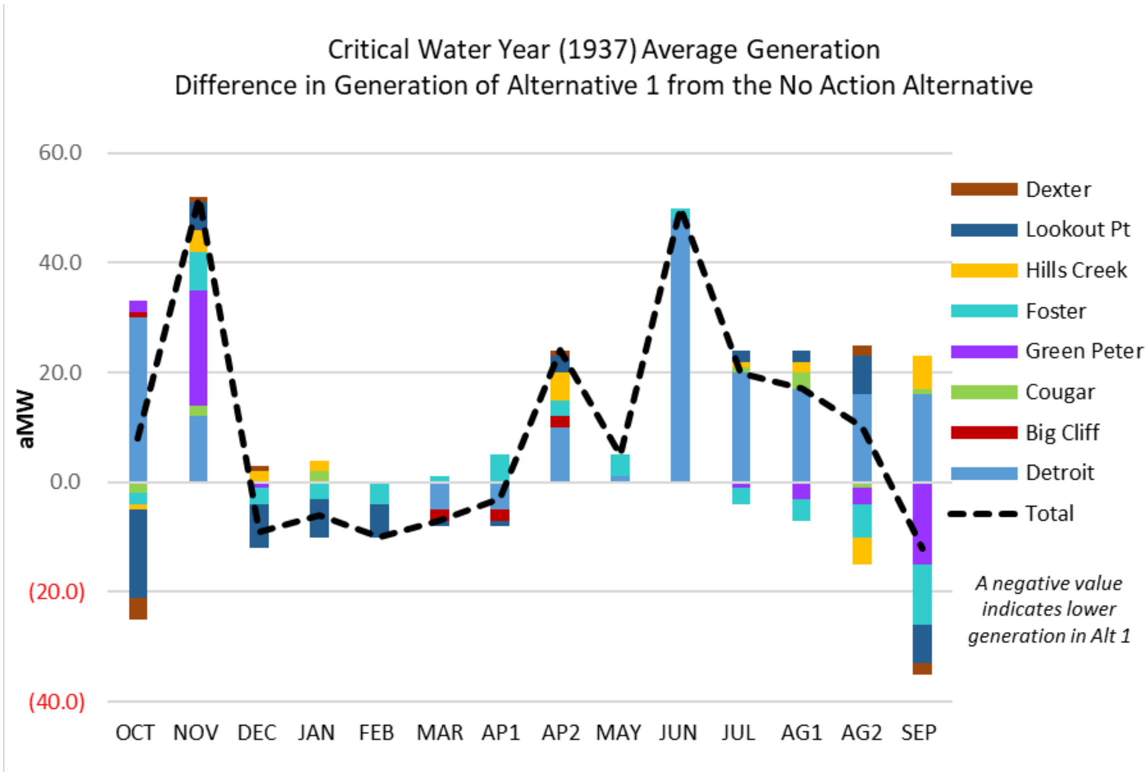

Figure 2.2-4. Critical Water Year (1937) Average Generation: Difference in Generation of Alternative 1 from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.

Source: HYDSIM modeling results.

Alternative 1: Critical Water Year (1937) vs. 73-Year Average Generation

Overall, the annual average generation (aMW) for the combined WVS projects under Alternative 1 was higher than the NAA by approximately 6.7 and 4.7 percent in the Critical Water Year (1937) Average Generation and 73-Year Average Generation scenarios, respectively (Table 2.2-3). Decreases in generation occurred during the months of December through May and September, which were offset by increased generation during other months. A similar pattern of decreased generation was seen for the critical water year with the exception that there were generation increases in May and the latter half of April.

Energy: Alternative 2A compared to NAA

Table 2.2- depicts the differences between Alternative 2A and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation of the combined WVS projects. Positive differences indicate an increase, and negative differences indicate a decrease in average generation (aMW) from the NAA.

Figure 2.2-5 and Figure 2.2-6 illustrate the differences in generation of individual WVS projects between Alternative 2A and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation, respectively. Individual project blocks indicate the amount of change in each project's monthly average generation (aMW) from the NAA. Project blocks above the zero line indicate a project under Alternative 2A generated more than the NAA; blocks below the zero line indicate less generation under Alternative 2A than the NAA. The total line indicates the difference in monthly average generation (aMW) for all WVS projects combined from the NAA.

Alternative 2A: 73-YEAR AVERAGE GENERATION

Table 2.2- indicates an annual average decrease of 4 aMW for the WVS projects combined under Alternative 2A compared to the NAA. Differences in average generation of the WVS projects between NAA and Alternative 2A primarily result from the following:

OCT: Higher Alternative 2A generation at Detroit, Foster, and Lookout Point Dams offset reduced generation at Green Peter Dam, resulting in an increase of 37.7 aMW of generation in this period. Cougar Dam generation is largely unchanged between the NAA and Alternative 2A in this period since downstream fish passage is provided through a structural measure (i.e., FSS) instead of operationally.

NOV - MAY: Alternative 2A has lower generation compared to NAA. In the winter and later spring months, Green Peter Dam is the primary driver of the change, whereas in early spring decreased generation at Hills Creek Dam additionally contributes to the lower net generation. Detroit, Cougar, and Dexter exhibit smaller decreases in generation. In the winter and late spring months, Green Peter would be the primary driver of the change. Decreased generation at Hills Creek in the early spring months additionally contributes to the lower net generation of Alternative 2A compared to the No Action Alternative.

JUN – SEPT: Higher generation at Detroit Dam is the main driver for the increased generation in Alternative 2A compared to the NAA during this period.

Table 2.2-4. 73-Year Average Generation and Critical Water Year (CWY, 1937) Average Generation at the WVS Projects: Alternative 2A relative to NAA, in aMW[1/]

	AVG GEN NAA	AVG GEN Alternative 2A	AVG GEN Difference	CWY GEN NAA	CWY GEN Alternative 2A	CWY GEN Difference
Oct	134	172	38	119	136	17
Nov	230	217	-13	156	163	7
Dec	231	178	-53	80	64	-16
Jan	235	205	-30	47	39	-8
Feb	147	140	-7	67	57	-10
Mar	143	131	-12	121	78	-43
Apr I	177	151	-26	188	182	-6
Apr II	182	146	-36	227	227	0
May	222	201	-21	356	330	-26
Jun	162	189	27	264	291	27
Jul	106	126	20	111	136	25
Aug I	114	128	14	115	122	7
Aug II	118	130	12	124	129	5
Sep	151	166	15	155	177	22
Annual Average[2/]	**171**	**167**	**-4**	**150**	**150**	**0**

1/ HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
2/ The Annual Average is a weighted average to account for the different number of days in the 14 periods.
Source: HYDSIM modeling results.

Alternative 2A: Critical Water Year (1937) Average Generation vs. 73-Year Average Generation

Overall, the annual average generation (aMW) under Alternative 2A was lower than the NAA by approximately 2.3 percent in the 73-Year Average Generation scenario and there was no difference between the NAA and the Critical Water Year (1937) Average Generation (Table 2.2-4). Lower annual average generation in Alternative 2B was primarily driven by reduced generation at Green Peter Dam in the late fall through spring, especially in the winter months. Generation increases in summer and early fall months were primarily driven by increased outflows through turbines at Detroit Dam (associated with replacement of temperature management spills with a temperature control tower), which offset the extent of the annual average reduction.

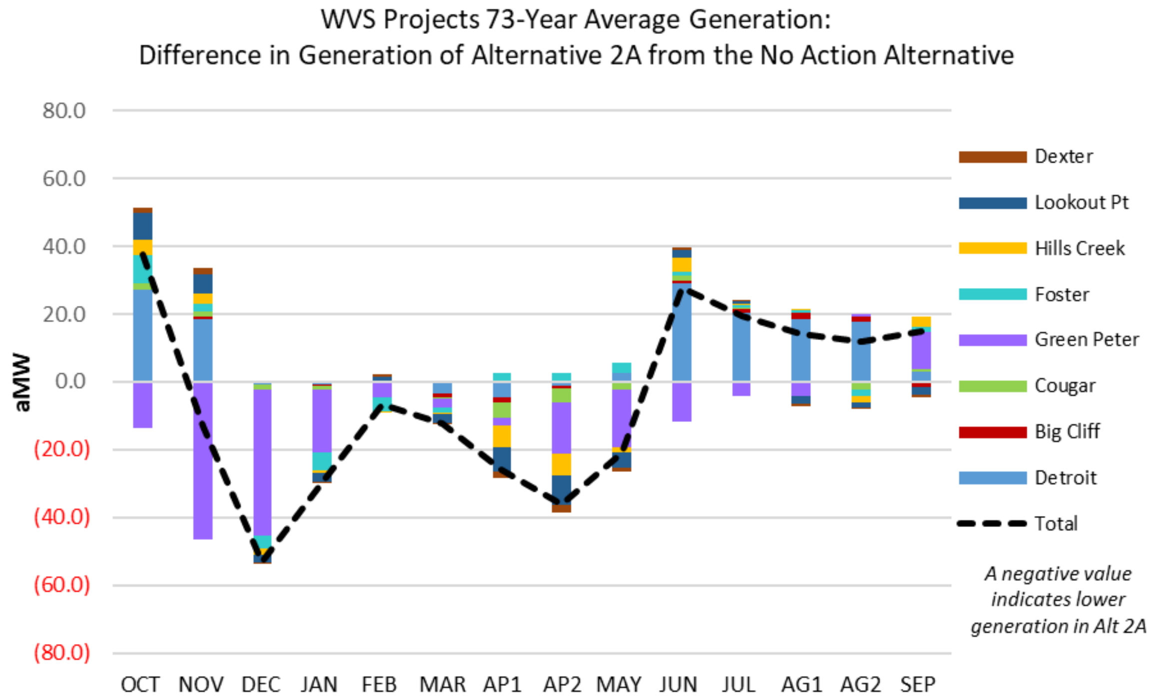

Figure 2.2-5. 73-Year Average Generation: Difference in Generation of Alternative 2A from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.

Source: HYDSIM modeling results.

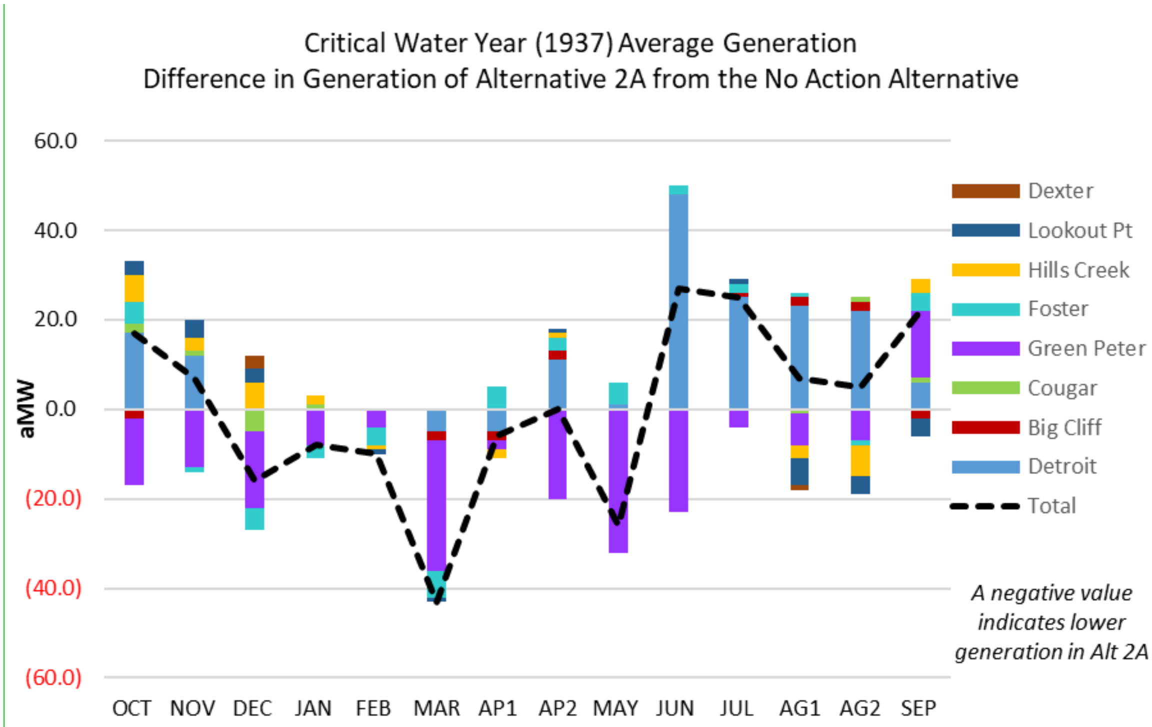

Figure 2.2-6. Critical Water Year (1937) Average Generation: Difference in Generation of Alternative 2A from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.

Source: HYDSIM modeling results.

Energy: Alternative 2B compared to NAA

Table 2.2-5 depicts the differences between Alternative 2B and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation for the WVS projects. Positive differences indicate an increase, and negative differences indicate a decrease in average generation (aMW) from the NAA.

Table 2.2-4. 73-Year Average Generation and Critical Water Year (CWY, 1937) Average Generation at the WVS Projects: Alternative 2B relative to NAA, in aMW1/

	AVG GEN NAA	AVG GEN Alternative 2B	AVG GEN Difference	CWY GEN NAA	CWY GEN Alternative 2B	CWY GEN Difference
Oct	134	147	13	119	113	-6
Nov	230	189	-41	156	126	-30
Dec	231	164	-67	80	66	-14
Jan	235	199	-36	47	33	-14
Feb	147	141	-6	67	50	-17
Mar	143	121	-22	121	67	-54
Apr I	177	138	-39	188	163	-25
Apr II	182	132	-50	227	184	-43
May	222	183	-39	356	306	-50
Jun	162	169	7	264	272	8
Jul	106	115	9	111	123	12
Aug I	114	119	5	115	123	8
Aug II	118	121	3	124	127	3
Sep	151	157	6	155	179	24
Annual Average2/	171	153	-18	150	136	-14

1/ HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
2/ The Annual Average is a weighted average to account for the different number of days in the 14 periods.
Source: HYDSIM modeling results.

Figure 2.2-7 and Figure 2.2-8 illustrate the differences in generation of individual WVS projects between Alternative 2B and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation, respectively. Individual project blocks indicate the amount of change in each project's monthly average generation (aMW) from the NAA. Project blocks above the zero line indicate a project under Alternative 2B generated more than the NAA; blocks below the zero line indicate less generation under Alternative 2B than the NAA. The total line indicates the difference in monthly average generation (aMW) for all WVS projects combined from the NAA.

Alternative 2B: 73-Year Average Generation

Table 2.2-5 indicates an annual average decrease of 18 aMW for the WVS projects combined under Alternative 2B compared to the NAA. Generation differences between NAA and Alternative 2B primarily result from the following:

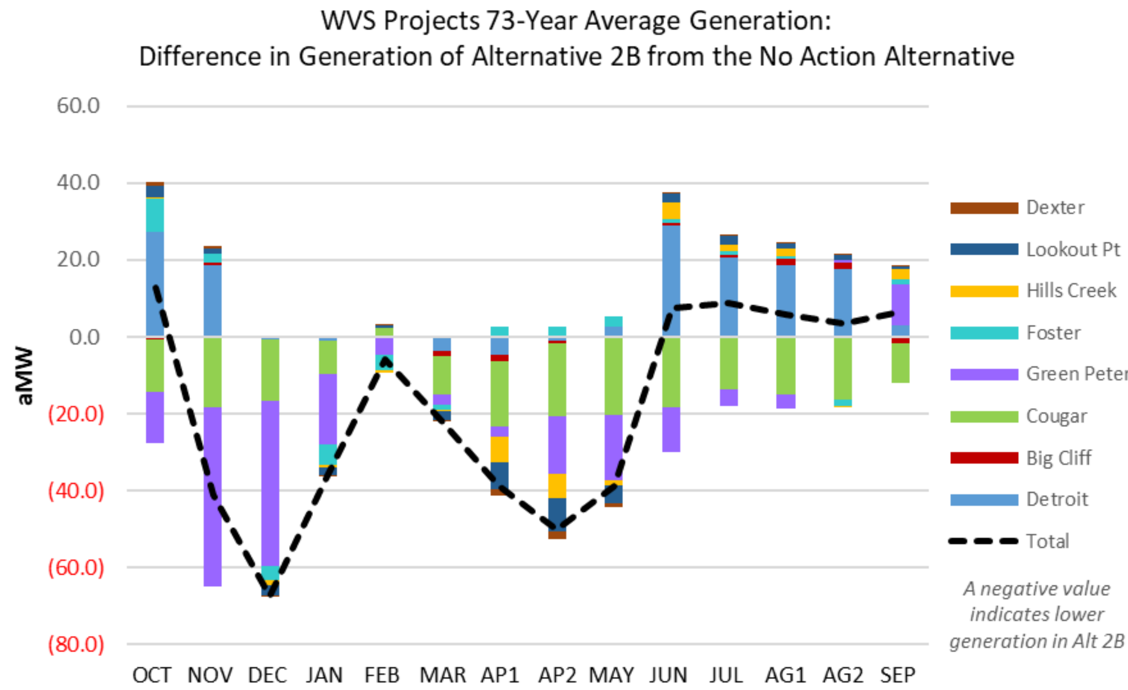

Figure 2.2-7. 73-Year Average Generation: Difference in Generation of Alternative 2B from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
Source: HYDSIM modeling results.

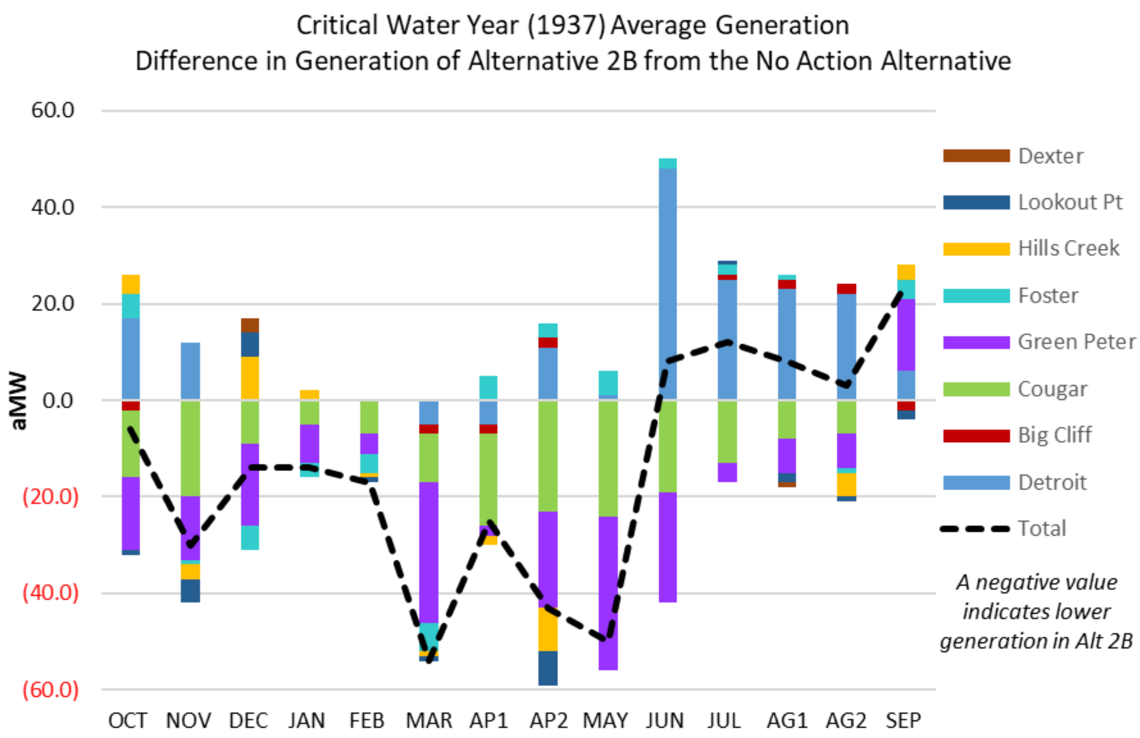

Figure 2.2-8. Critical Water Year (1937) Average Generation: Difference in Generation of Alternative 2B from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
Source: HYDSIM modeling results.

OCT: Higher average generation at Detroit and Foster dams under Alternative 2B offset reduced generation at Cougar and Green Peter, resulting in an increase of approximately 13 aMW of generation for all WVS projects combined in October.

NOV - MAY: Alternative 2B has lower average generation compared to the NAA for all WVS projects combined during these months. Cougar and Green Peter dams are the primary drivers of the difference. In fact, Cougar Dam has negligible generation in all months except January and February.

JUN – SEPT: Alternative 2B has higher average generation compared to the NAA for all WVS projects combined during these months. Higher Alternative 2B average generation at Detroit and Foster dams was the largest contributor to this increase. Reduced generation at Cougar Dam and other projects moderated the increase in average generation during this period.

Alternative 2B: Critical Water Year (1937) Average Generation vs. 73-Year Average Generation

Overall, the annual average generation (aMW) for the combined WVS projects under Alternative 2B was lower than the NAA by approximately 9.3 and 10.5 percent in the Critical Water Year (1937) Average Generation and 73-Year Average Generation scenarios, respectively (Table 2.2-3). Lower annual average generation in Alternative 2B was primarily driven by reduced generation at Cougar and Green Peter dams in the late fall through spring, especially in the winter months. Generation increases in summer and early fall months were primarily driven by increased outflows through turbines at Detroit Dam (associated with replacement of temperature management spills with a temperature selective withdrawal structure), which offset the extent of the annual average reduction.

Energy: Alternative 3A compared to NAA

Table 2.2-6 depicts the differences between Alternative 3A and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation for the WVS projects. Positive differences indicate an increase, and negative differences indicate a decrease in average generation (aMW) from the NAA.

Figure 2.2-9 and Figure 2.2-10 illustrate the differences in generation of individual WVS projects between Alternative 3A and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation, respectively. Individual project blocks indicate the amount of change in each project’s monthly average generation (aMW) from the NAA. Project blocks above the zero line indicate a project under Alternative 3A generated more than the NAA; blocks below the zero line indicate less generation under Alternative 3A than the NAA. The total line indicates the difference in monthly average generation (aMW) for all WVS projects combined from the NAA.

Table 2.2-5. 73-Year Average Generation and Critical Water Year (CWY, 1937) Average Generation at the WVS Projects: Alternative 3A relative to NAA, in aMW[1/]

	AVG GEN NAA	AVG GEN Alternative 3A	AVG GEN Difference	CWY GEN NAA	CWY GEN Alternative 3A	CWY GEN Difference
Oct	134	51	-83	119	36	-83
Nov	230	48	-182	156	12	-144
Dec	231	83	-148	80	22	-58
Jan	235	175	-60	47	21	-26
Feb	147	164	17	67	38	-29
Mar	143	115	-28	121	56	-65
Apr I	177	96	-81	188	125	-63
Apr II	182	71	-111	227	138	-89
May	222	45	-177	356	67	-289
Jun	162	43	-119	264	67	-197
Jul	106	53	-53	111	80	-31
Aug I	114	58	-56	115	69	-46
Aug II	118	66	-52	124	66	-58
Sep	151	92	-59	155	125	-30
Annual Average[2/]	**171**	**84**	**-87**	**150**	**60**	**-90**

1/ HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
2/ The Annual Average is a weighted average to account for the different number of days in the 14 periods.
Source: HYDSIM modeling results.

Alternative 3A: 73-Year Average Generation

Table 2.2-6 indicates an annual average decrease of 87 aMW for the WVS projects combined under ALT 3A compared to the NAA. Generation differences between NAA and Alternative 3A primarily result from the following:

SEPT – JAN: In the fall and early winter, Alternative 3A average generation is substantially reduced from the NAA at most projects except Foster (which had nearly double generation in October) and Dexter dams (which was unchanged). Fall deep reservoir drawdowns (Green Peter, Hills Creek, Cougar, Lookout Point, and Detroit dams) and spill operations conducted for fish passage (Green Peter, Foster, Hills Creek, Dexter, and Big Cliff dams) contribute to lower generation as a result of associated decreases in outflows through turbines.

FEB: This is the only month in which Alternative 3A average generation at all WVS projects combined is higher than the NAA. Higher outflows at Detroit, Big Cliff, and Cougar appear primarily responsible for the increase in generation. Spill and reservoir drawdown operations are not in effect during this period.

MAR – AUG2: In the spring and summer, Alternative 3A average generation is substantially reduced from the NAA at most projects. The impact is pronounced at Detroit, Cougar, Lookout Point, and Dexter dams. In May and June, several projects have average generation values of less than 1 aMW. Deep spring reservoir drawdowns and spring and summer surface spill operations reduce generation as a result of associated decreases in outflows through turbines. Looking at Detroit Dam operations in May over several historical water years, for example, reveals that the combination of high spill values and lower reservoir elevations in the deep drawdown regime would result in less turbine flows and less corresponding generation.

Alternative 3A: Critical Water Year (1937) Average Generation vs. 73-Year Average Generation

Overall, the annual average generation (aMW) under Alternative 3A was less than the NAA by approximately 60.0 and 50.9 percent in the Critical Water Year (1937) Average Generation and 73-Year Average Generation scenarios, respectively (Table 2.2-6). Lower annual average generation in Alternative 3B was primarily driven by spill operations and deep fall and spring season reservoir drawdowns, which reduced generation at several projects as a result of associated decreases in outflows through turbines. It appears that deep spring drawdown and/or summer spills in the critical water year scenario would result in greater generation reductions compared to the NAA than over the 73 year average. It is also worth noting in the Alternative 3A critical water year, winter generation (NOV – JAN) is less than 20 aMW for the combined WVS projects.

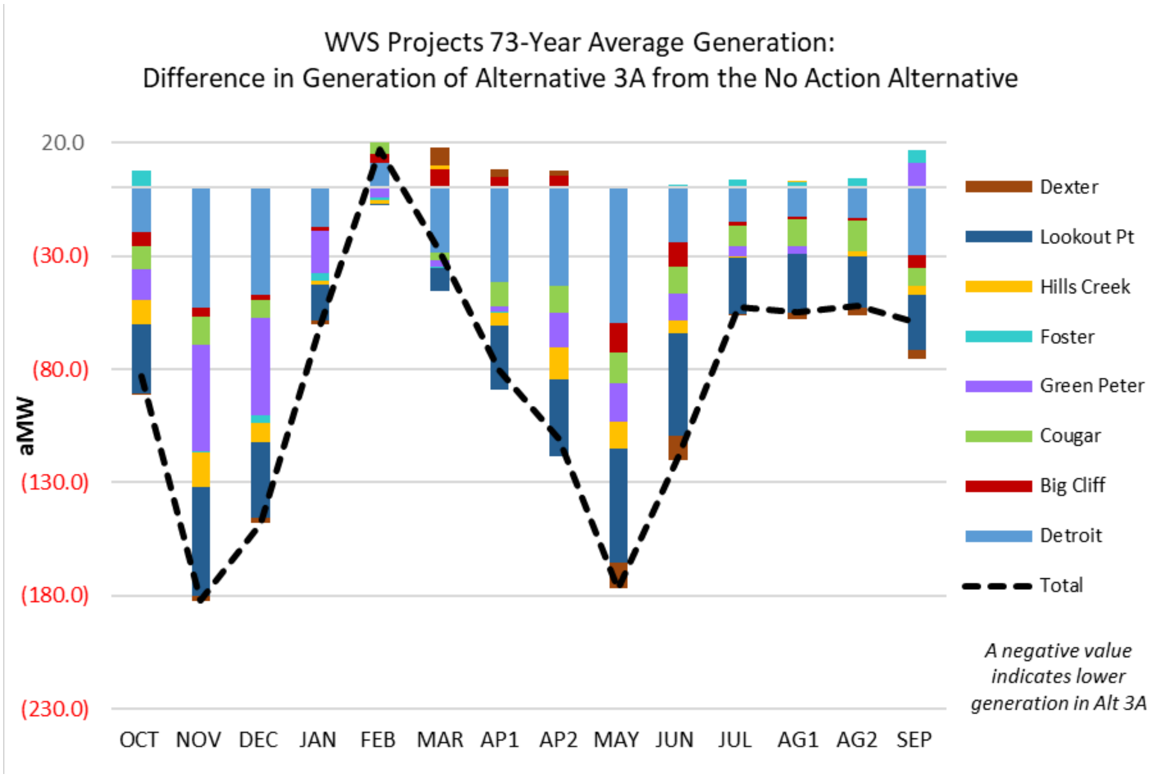

Figure 2.2-9. 73-Year Average Generation: Difference in Generation of Alternative 3A from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
Source: HYDSIM modeling results.

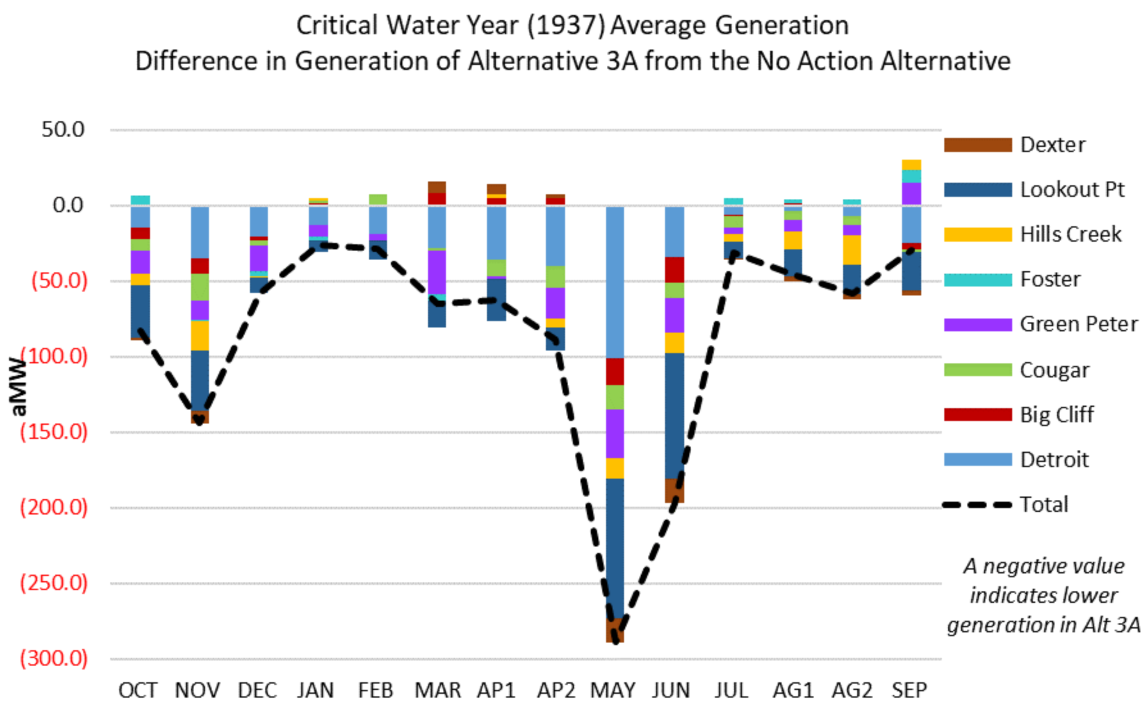

Figure 2.2-10. Critical Water Year (1937) Average Generation: Difference in Generation of Alternative 3A from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
Source: HYDSIM modeling results.

Energy: Alternative 3B compared to NAA

Table 2.2-7 depicts the differences between Alternative 3B and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation for the WVS projects. Positive differences indicate an increase, and negative differences indicate a decrease in average generation (aMW) from the NAA.

Table 2.2-6. 73-Year Average Generation and Critical Water Year (CWY, 1937) Average Generation at the WVS Projects: Alternative 3B relative to NAA, in aMW[1/]

	AVG GEN NAA	AVG GEN Alternative 3B	AVG GEN Difference	CWY GEN NAA	CWY GEN Alternative 3B	CWY GEN Difference
Oct	134	57	-77	119	45	-74
Nov	230	43	-187	156	14	-142
Dec	231	72	-159	80	17	-63
Jan	235	167	-68	47	15	-32
Feb	147	185	38	67	30	-37
Mar	143	132	-11	121	69	-52
Apr I	177	118	-59	188	106	-82
Apr II	182	82	-100	227	103	-124
May	222	68	-154	356	105	-251
Jun	162	55	-106	264	84	-180
Jul	106	62	-44	111	88	-23
Aug I	114	60	-54	115	76	-39
Aug II	118	75	-43	124	91	-33
Sep	151	112	-39	155	152	-3
Annual Average[2/]	**171**	**93**	**-79**	**150**	**67**	**-83**

1/ HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
2/ The Annual Average is a weighted average to account for the different number of days in the 14 periods.
Source: HYDSIM modeling results.

Figure 2.2-11 and Figure 2.2-12 illustrate the differences in generation of individual WVS projects between Alternative 3B and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation, respectively. Individual project blocks indicate the amount of change in each project's monthly average generation (aMW) from the NAA. Project blocks above the zero line indicate a project under Alternative 3B generated more than the NAA; blocks below the zero line indicate less generation under Alternative 3B than the NAA. The total line indicates the difference in monthly average generation (aMW) for all WVS projects combined from the NAA.

Alternative 3B: 73-Year Average Generation

Table 2.2-7 indicates an annual average decrease of 79 aMW for the WVS projects combined under Alternative 3A compared to the NAA. Generation differences between NAA and Alternative 3B primarily result from the following:

SEPT – JAN: In the fall and early winter, Alternative 3B average generation is substantially reduced from the NAA at all projects. Fall deep reservoir drawdowns (Green Peter, Hills Creek, Cougar, Lookout Point, and Detroit dams) and spill operations conducted for fish passage (Green Peter, Foster, Hills Creek, Dexter, and Big Cliff dams) contribute to lower generation as a result of associated decreases in outflows through turbines.

FEB: This is the only period in which Alternative 3B generation at all WVS projects combined is higher than the NAA. Higher flows at Green Peter, Hills Creek, Foster, and Lookout Point appear primarily responsible for the increase in generation. Spill and drawdown operations are not in effect during this period.

MAR – AUG2: In the spring and summer, Alternative 3B average generation is substantially reduced from the NAA at most projects. The impact is most pronounced at Cougar associated with the deep spring reservoir drawdown to the diversion tunnel. There is higher spring/summer generation at Detroit and Big Cliff in the summer compared to the NAA. Deep spring drawdown at Hills Creek and Green Peter is allowed in Alternative 3B, which can be seen by the sharp reduction in generation at Green Peter from March to April. From April through June, several projects have average generation values of less than 1 aMW. Looking at the Green Peter operations in June over several historical water years, for example, reveals that the combination of high spill values, lower flows, and lower elevations in the deep drawdown regime lead to less turbine flows and less corresponding generation.

Alternative 3B: Critical Water Year (1937) Average Generation vs. 73-Year Average Generation

Overall, the annual average generation (aMW) under Alternative 3B was less than the NAA by approximately 55.3 and 45.6 percent in the Critical Water Year (1937) Average Generation and 73-Year Average Generation scenarios, respectively (Table 2.2-7). Lower annual average generation in Alternative 3B was primarily driven by spill operations and deep fall and spring season reservoir drawdowns, which reduced generation at several projects as a result of associated decreases in outflows through turbines. Decreases were particularly pronounced from April through June. It appears that deep spring drawdown and/or summer spills in the critical water year scenario would result in greater generation reductions compared to the NAA than over the 73 year average. It is also worth noting in the Alternative 3B critical water year, winter generation (NOV – JAN) is less than 20 aMW for the combined WVS projects.

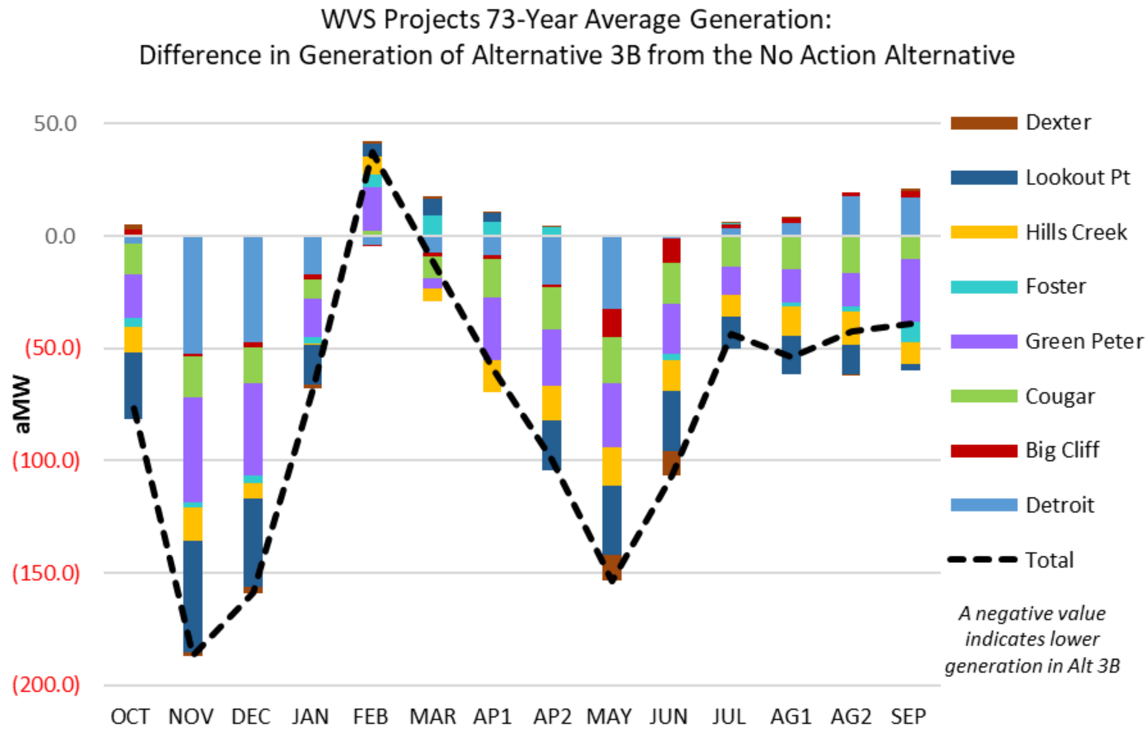

Figure 2.2-11. 73-Year Average Generation: Difference in Generation of Alternative 3B from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
Source: HYDSIM modeling results.

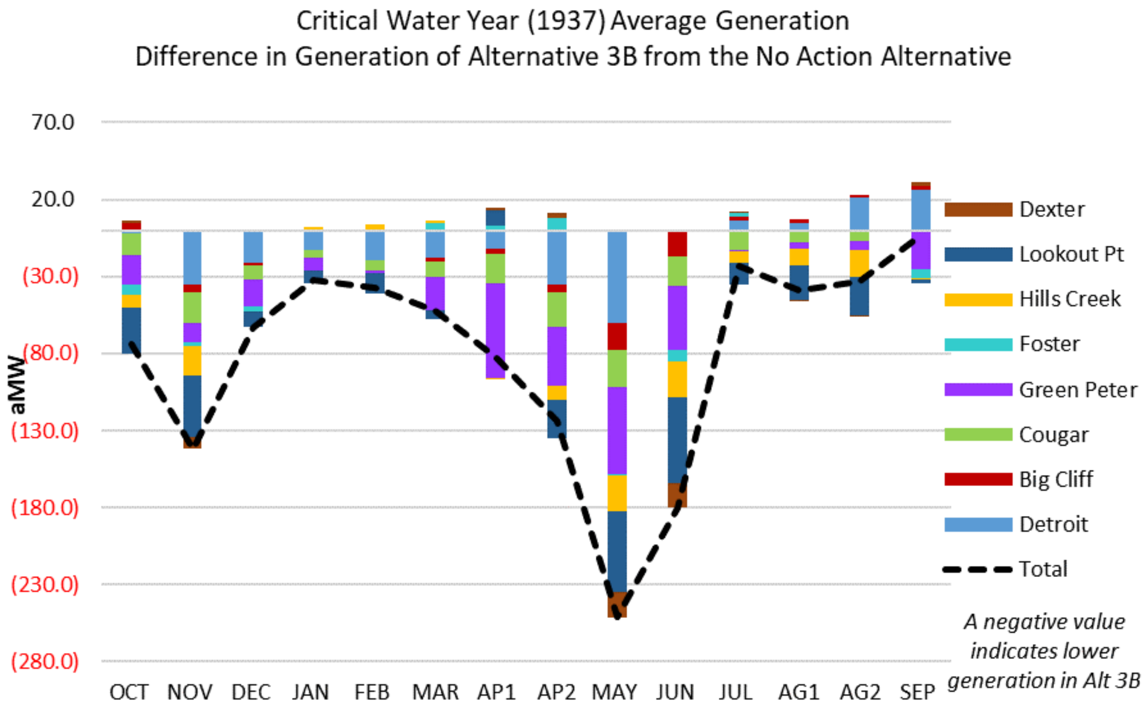

Figure 2.2-12. Critical Water Year (1937) Average Generation: Difference in Generation of Alternative 3B from NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
Source: HYDSIM modeling results.

Energy: Alternative 4 compared to NAA

Table 2.2-8 depicts the differences between Alternative 4 and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation for the WVS projects. Positive differences indicate an increase, and negative differences indicate a decrease in average generation (aMW) from the NAA.

Table 2.2-7. 73-Year Average Generation and Critical Water Year (CWY, 1937) Average Generation at the WVS Projects: Alternative 4 relative to NAA, in aMW1/

	AVG GEN NAA	AVG GEN Alternative 4	AVG GEN Difference	CWY GEN NAA	CWY GEN Alternative 4	CWY GEN Difference
Oct	134	160	26	119	129	10
Nov	230	250	20	156	174	18
Dec	231	223	-8	80	59	-21
Jan	235	228	-7	47	36	-11
Feb	147	147	0	67	59	-8
Mar	143	132	-11	121	115	-6
Apr I	177	151	-26	188	176	-12
Apr II	182	145	-37	227	227	0
May	222	199	-22	356	325	-31
Jun	162	189	27	264	285	21
Jul	106	126	19	111	134	23
Aug I	114	128	15	115	123	8
Aug II	118	130	13	124	126	2
Sep	151	137	-14	155	137	-18
Annual Average2/	171	172	1	150	148	-2

1/ HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
2/ The Annual Average is a weighted average to account for the different number of days in the 14 periods.
Source: HYDSIM modeling results.

Figure 2.2-13 and Figure 2.2-14 illustrate the differences in generation of individual WVS projects between Alternative 4 and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation, respectively. Individual project blocks indicate the amount of change in each project's monthly average generation (aMW) from the NAA. Project blocks above the zero line indicate a project under Alternative 4 generated more than the NAA; blocks below the zero line indicate less generation under Alternative 4 than the NAA. The total line indicates the difference in monthly average generation (aMW) for all WVS projects combined from the NAA.

Alternative 4: 73-YEAR AVERAGE GENERATION

Table 2.2-8 indicates an annual average increase of 1 aMW for the WVS projects combined under Alternative 4 compared to the NAA. Generation differences between NAA and Alternative 4 primarily result from the following:

OCT - NOV: Higher Alternative 4 generation at combined WVS projects during this period is largely driven by increases at Detroit, Lookout Point, and to a lesser degree, Hills Creek dams, which may be driven by water temperature control operations instead of NAA spill operations. Cold water regulating outlet discharge during this period may also contribute to reduction of generation at Green Peter Dam compared to the NAA.

DEC – MAY: During December through March, the Alternative 4 operations generally result in minor changes, typically reduction, in generation at all WVS projects without a main driver. In April and May, reduced generation at Green Peter Dam may be attributed to the start of surface spill measures.

JUN – AUG: Higher Alternative 4 generation at combined WVS projects during this period is largely driven by increases at Detroit Dam that are likely due to decreased temperature spill relative to the NAA. Conversely, Green Peter Dam has lower generation in this period, likely from the Alternative 4 surface spillway operation compared to the NAA.

SEPT: Lower Alternative 4 generation compared to NAA is driven by reductions at Green Peter and Foster dams during September. At Green Peter Dam, surface spill measures are still in effect, and at Foster Dam increased spill is accompanied by decreased flows.

Alternative 4: Critical Water Year (1937) Average Generation vs. 73-Year Average Generation

Overall, the annual average generation (aMW) for the combined WVS projects under Alternative 4 was similar to the NAA for both the Critical Water Year (1937) Average Generation and the 73-Year Average Generation scenarios with a 1.3 percent decrease and 0.6 percent increase, respectively (Table 2.2-8). Over the 73 year average, there were decreases in generation during the months of December through May and September, which were offset by increased generation during other months. A similar pattern of decreased generation was seen for the critical water year with the exception that there was no change in generation in the latter half of April.

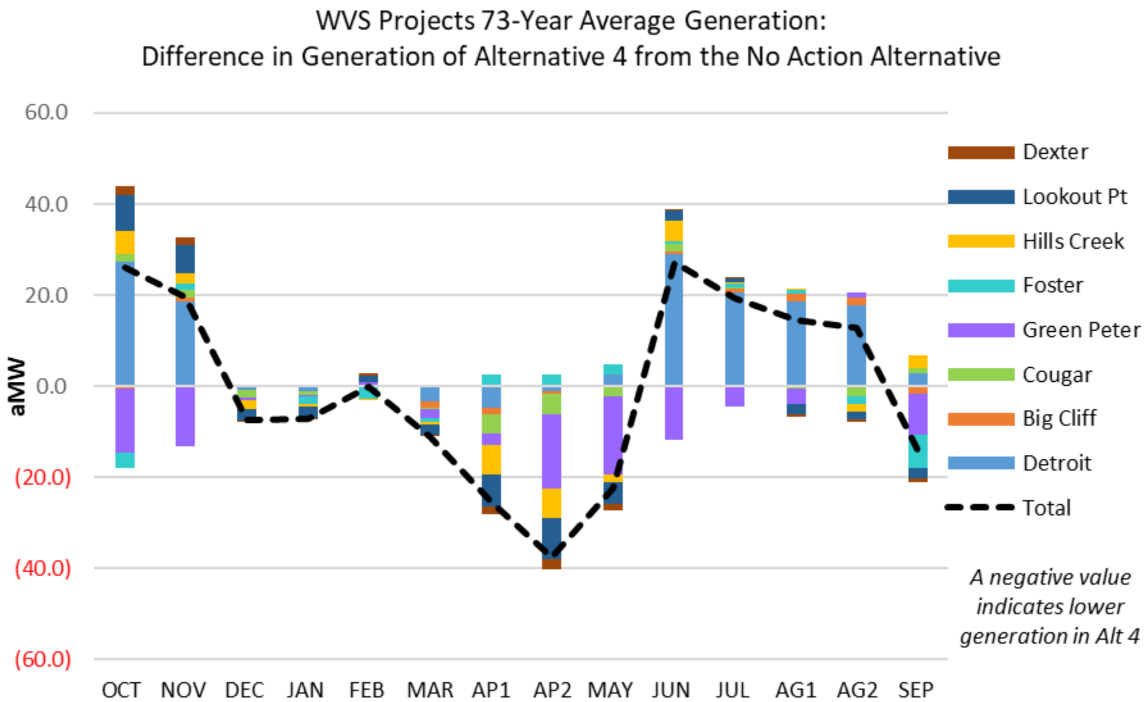

Figure 2.2-13. 73-Year Average Generation: Difference in Generation of Alternative 4 from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
Source: HYDSIM modeling results.

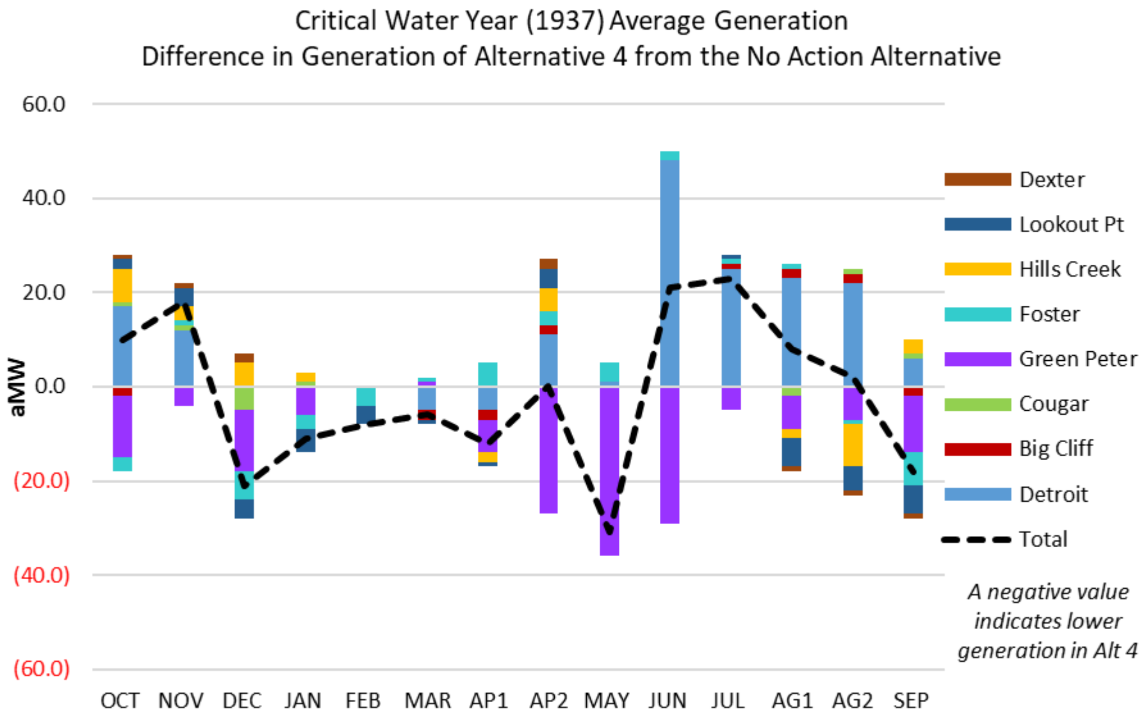

Figure 2.2-14. Critical Water Year (1937) Average Generation: Difference in Generation of Alternative 4 from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.

Source: HYDSIM modeling results.

Energy: Interim Operations compared to NAA

Table 2.2-9 depicts the differences between Interim Operations and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation for the WVS projects. Positive differences indicate an increase, and negative differences indicate a decrease in average generation (aMW) from the NAA.

Table 2.2-8. 73-Year Average Generation and Critical Water Year (CWY, 1937) Average Generation at the WVS Projects: Interim Operations relative to NAA, in aMW.[1/]

	AVG GEN NAA	AVG GEN INT. OPERATIONS MEASURE	AVG GEN Difference	CWY GEN NAA	CWY GEN INT. OPERATIONS MEASURE	CWY GEN Difference
Oct	134	129	-5	119	108	-11
Nov	230	112	-118	156	74	-82
Dec	231	107	-124	80	35	-45
Jan	235	159	-76	47	20	-27
Feb	147	127	-20	67	27	-40
Mar	143	100	-43	121	78	-43
Apr I	177	81	-96	188	106	-82
Apr II	182	72	-110	227	87	-140
May	222	133	-89	356	211	-145
Jun	162	152	-10	264	250	-14
Jul	106	111	5	111	131	20
Aug I	114	98	-16	115	107	-8
Aug II	118	100	-18	124	102	-22
Sep	151	132	-19	155	159	4
Annual Average[2/]	171	120	-52	150	108	-42

1/ HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
2/ The Annual Average is a weighted average to account for the different number of days in the 14 periods.
Source: HYDSIM modeling results.

Figure 2.2-15 and Figure 2.2-16 illustrate the differences in generation of individual WVS projects between InterimTerm Operations and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation, respectively. Individual project blocks indicate the amount of change in each project's monthly average generation (aMW) from the NAA. Project blocks above the zero line indicate a project under Interim Operations generated more than the NAA; blocks below the zero line indicate less generation under Interim Operations than the NAA. The total line indicates the difference in monthly average generation (aMW) for all WVS projects combined from the NAA.

Interim Operations: 73-Year Average Generation

Table 2.2-9 indicates an annual average decrease of 52 aMW for the WVS projects combined under Interim Operations compared to the NAA. Generation differences between NAA and Interim Operations primarily result from the following:

AUG 1 – OCT: In the late summer and early fall, overall generation for Interim Operations is lower than NAA, largely due to decreased generation at Lookout Point. At Lookout Point, summer and fall downstream passage operations include deep drawdowns, increased spill and limited use of turbines.

NOV - JAN: In the winter months, generation under Interim Operations is markedly lower than NAA. This change is driven by substantially decreased generation at Detroit, Green Peter, and Lookout Point, accompanied by moderately decreased generation at Foster and Cougar. At Detroit, Interim Operations measures for improved downstream fish passage includes modeling approximately 60 percent of daily flow going through the upper regulating outlet and approximately 40 percent through the penstock and turbines; the corresponding decrease in generation follows. Interim Operations contains a deep drawdown operation for improved fish passage at Green Peter which, as modeled, leads to a 73-year average generation of 0.5 aMW in NOV (67 of 73 years no generation) and 2.9 aMW (50 of 73 years no generation) in DEC. Similarly, at Lookout Point, the 73-year average generation is modeled at 1 aMW in NOV (70 of 73 years no generation) and 8 aMW in DEC (57 of 73 years no generation).

FEB: Decreased generation at Detroit, and to a lesser extent Foster, drives the lowered Interim Operations generation compared to NAA. At Foster, a delayed refill measure keeps the reservoir at minimum conservation pool, the spillway is operated at night, and only one turbine unit will be operated.

MAR – MAY: All projects have decreased spring generation with the exception of Hills Creek in March and Green Peter and Big Cliff in May. At Detroit, spring downstream fish passage via strategic use of the spillway and turbines results in decreased generation as the operation calls for generation during the day and spill at night. Green Peter operations for improved juvenile fish passage with continuous spill in the spring lead to decreased generation through the beginning of May. Lookout Point generation would also decrease substantially in the spring months.

JUN – JUL: JUL is the only period in which the Interim Operations WVS has marginally higher total generation than the NAA, though the decrease in generation at Lookout Point largely offsets the increased generation at Green Peter.

Interim Operations: Critical Water Year (1937) Average Generation vs. 73-Year Average Generation

Overall, the annual average generation (aMW) for the combined WVS projects under Interim Operations was lower than the NAA for both the Critical Water Year (1937) Average Generation and the 73-Year Average Generation scenarios with a 28.2 percent decrease and 30.1 percent decrease, respectively (Table 2.2-9). Over the 73 year average, there were decreases in generation in all months except July. A similar pattern of decreased generation was seen for the critical water year with the exception that there was marginally more generation in September compared to NAA.

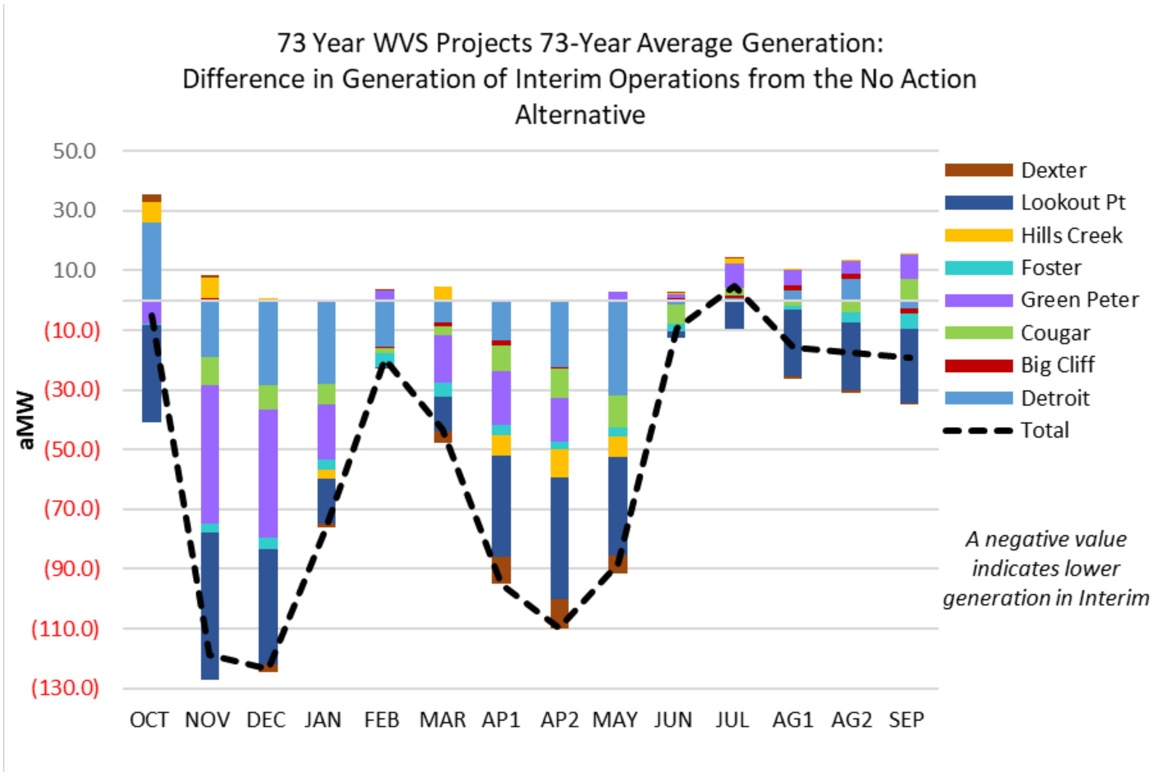

Figure 2.2-15. 73-Year Average Generation: Difference in Generation of Interim Operations from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves. Source: HYDSIM modeling results.

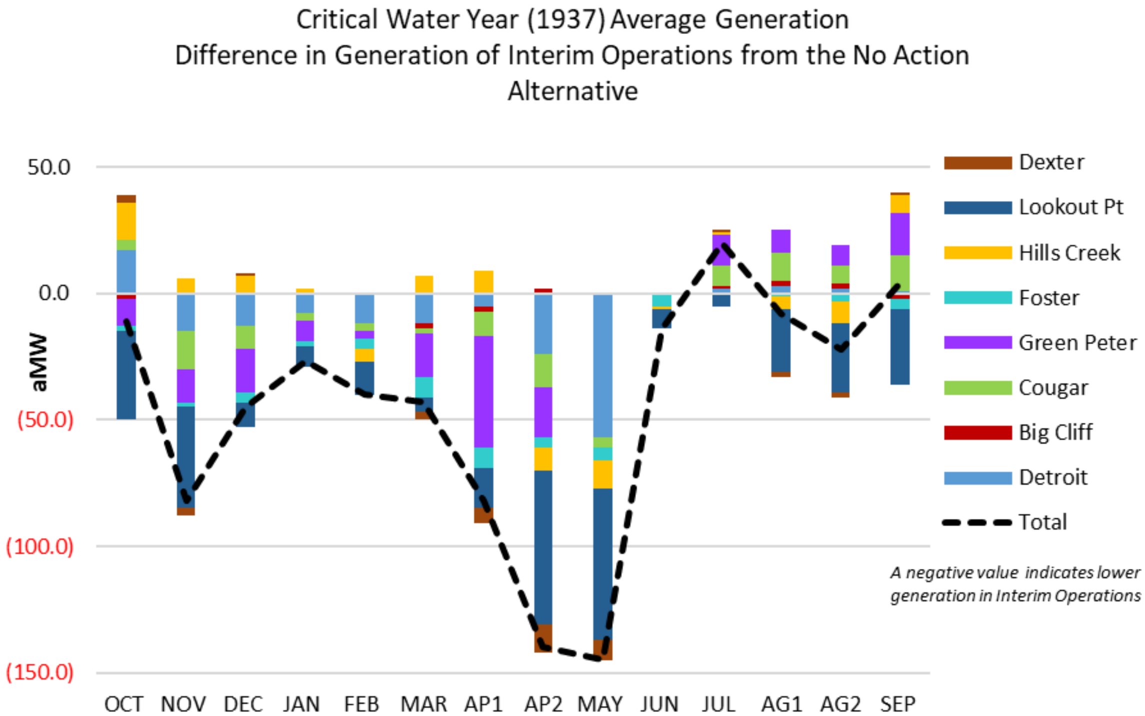

Figure 2.2-16. Critical Water Year (1937) Average Generation: Difference in Generation of Interim Operations from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves. Source: HYDSIM modeling results

Energy: Alternative 5 compared to NAA

Table 2.2-10 depicts the differences between Alternative 5 and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation for the WVS projects. Positive differences indicate an increase, and negative differences indicate a decrease in average generation (aMW) from the NAA. The results from this section are similar to those of Alternative 2B as Alternative 5 was derived from the earlier alternative but with small modifications to flow targets. At Hills Creek, for example, the elevation reaches the top of conservation storage less frequently under Alternative 5 than under Alternative 2B. Additionally, the lower minimum elevation is met more frequently. This operational difference helps explain the changes in generation tabulated below.

Table 2.2-9. 73-Year Average Generation and Critical Water Year (CWY, 1937) Average Generation at the WVS Projects: Alternative 5 relative to NAA, in aMW[1/]

	AVG GEN NAA	AVG GEN Alternative 5	AVG GEN Difference	CWY GEN NAA	CWY GEN Alternative 5	CWY GEN Difference
Oct	134	149	15	119	151	32
Nov	230	181	-49	156	107	-49
Dec	231	161	-69	80	38	-42
Jan	235	197	-38	47	27	-20
Feb	147	142	-5	67	47	-20
Mar	143	120	-23	121	67	-54
Apr I	177	143	-34	188	158	-30
Apr II	182	136	-46	227	183	-44
May	222	184	-38	356	303	-53
Jun	162	169	7	264	272	8
Jul	106	114	8	111	125	14
Aug I	114	118	5	115	116	1
Aug II	118	120	3	124	126	2
Sep	151	157	6	155	173	18
Annual Average[2/]	**171**	**153**	**-19**	**150**	**134**	**-17**

1/ HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
2/ The Annual Average is a weighted average to account for the different number of days in the 14 periods.
Source: HYDSIM modeling results.

Figure 2.2-17 and Figure 2.2-18 illustrate the differences in generation of individual WVS projects between Alternative 5 and the NAA for the 73-Year Average Generation and Critical Water Year (1937) Average Generation, respectively. Individual project blocks indicate the amount of change in each project's monthly average generation (aMW) from the NAA. Project blocks above the zero line indicate a project under Alternative 5 generated more than the NAA; blocks below the zero line indicate less generation under Alternative 5 than the NAA. The total line indicates the difference in monthly average generation (aMW) for all WVS projects combined from the NAA.

Alternative 5: 73-Year Average Generation

Table 2.2-10 indicates an annual average decrease of 19 aMW for the WVS projects combined under Alternative 5 compared to the NAA. Generation differences between NAA and Alternative 5 primarily result from the following:

OCT: Higher average generation at Detroit and Foster dams under Alternative 5 offset reduced generation at Cougar and Green Peter, resulting in an increase of approximately 15 aMW of generation for all WVS projects combined in October.

NOV - MAY: Alternative 5 has lower average generation compared to the NAA for all WVS projects combined during these months. Cougar and Green Peter dams are the primary drivers of the difference. In fact, Cougar Dam has negligible generation in all months except January and February.

JUN – SEPT: Alternative 5 has higher average generation compared to the NAA for all WVS projects combined during these months. Higher Alternative 5 average generation at Detroit and Foster dams was the largest contributor to this increase. Reduced generation at Cougar Dam and other projects moderated the increase in average generation during this period.

Alternative 5: Critical Water Year (1937) Average Generation vs. 73-Year Average Generation

Overall, the annual average generation (aMW) for the combined WVS projects under Alternative 5 was lower than the NAA by approximately 9.3 and 10.5 percent in the Critical Water Year (1937) Average Generation and 73-Year Average Generation scenarios, respectively (Table 2.2-10). Lower annual average generation in Alternative 5 was primarily driven by reduced generation at Cougar and Green Peter dams in the late fall through spring, especially in the winter months. Generation increases in summer and early fall months were primarily driven by increased outflows through turbines at Detroit Dam (associated with replacement of temperature management spills with a temperature control tower), which offset the extent of the annual average reduction.

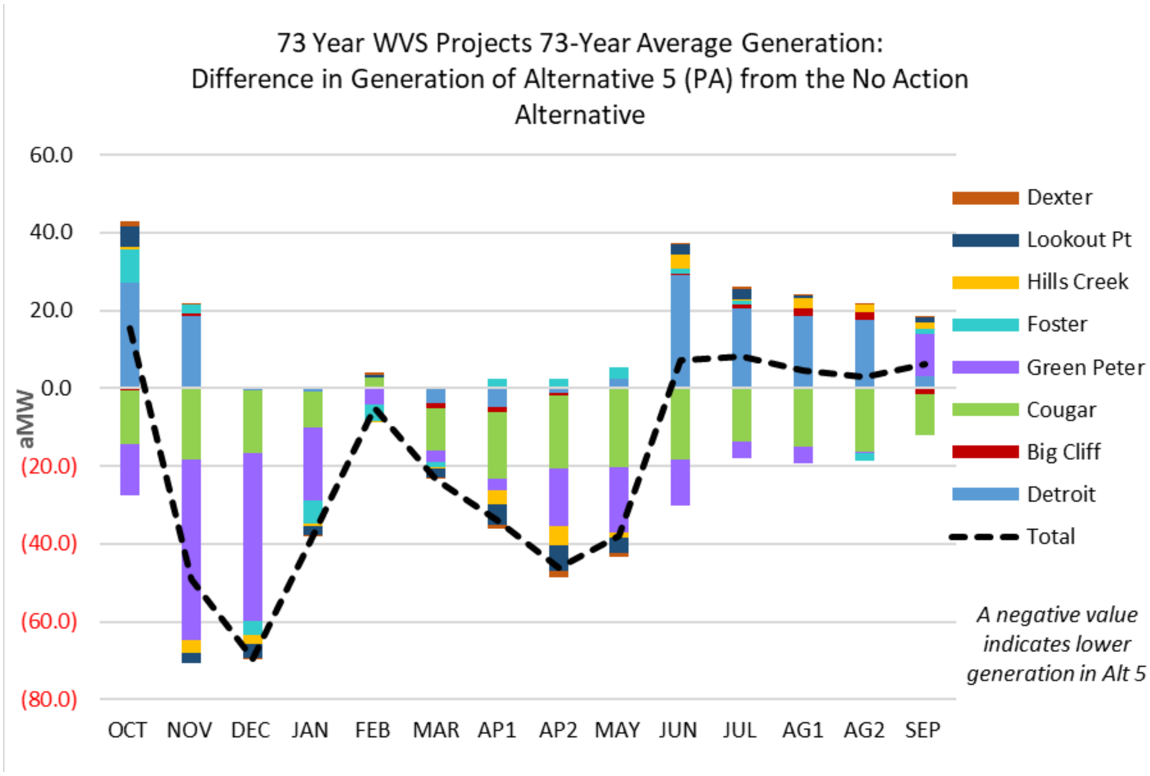

Figure 2.2-5. 73-Year Average Generation: Difference in Generation of Alternative 5 from the NAA

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.
Source: HYDSIM modeling results.

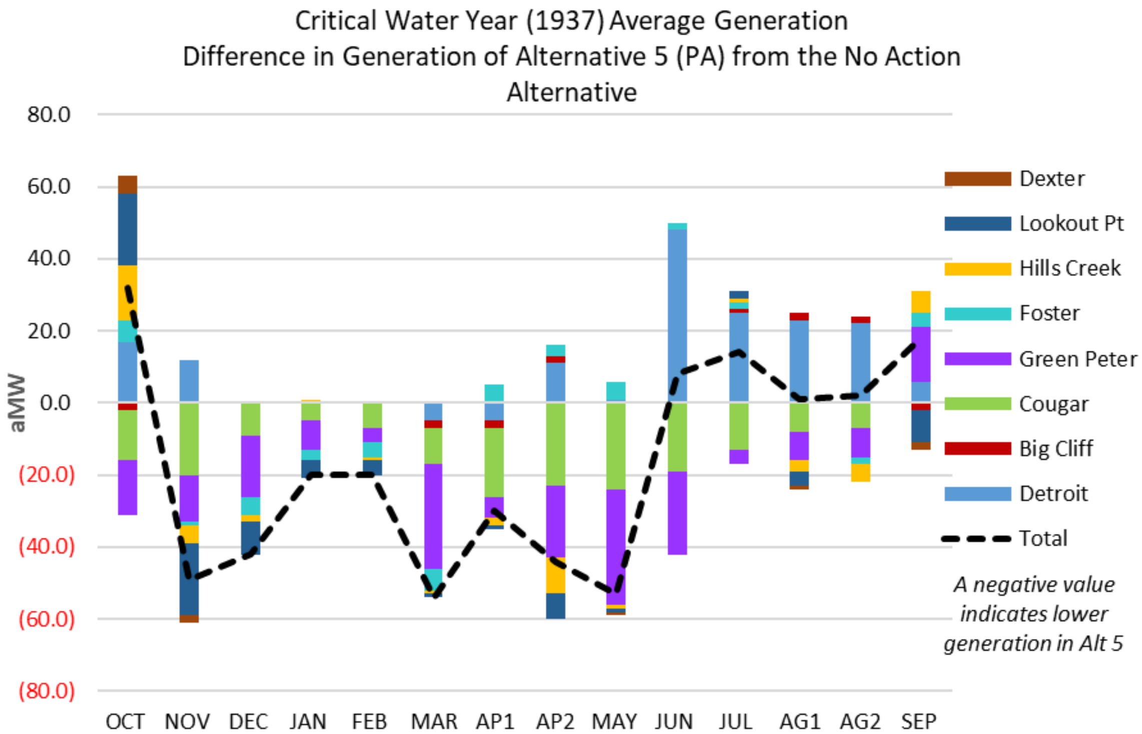

Figure 2.2-6. Critical Water Year (1937) Average Generation: Difference in Generation of Alternative 5 from the NAA.

Note: HYDSIM uses a 14-period time step. April and August are split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves.

Source: HYDSIM modeling results.

3. REGIONAL POWER SUPPLY AND REPLACEMENT RESOURCES

The operation, configuration, and maintenance changes described in the WVS Alternatives would affect the magnitude of power generated from the eight WVS projects, as detailed in Section 2 of this appendix. The WVS projects are a subset of the FCRPS (31 Federal dams), and the associated transmission infrastructure. The WVS projects are operated independently from all other resources of the FCRPS. All other FCRPS resources are modeled consistently with the CRSO Preferred Alternative (i.e., their project storage operations, outflows, and generation are the same in each WVS alternative). The FCRPS and other resources acquired by Bonneville to meet its firm power supply obligations constitute what is known as the Federal Base System. Fluctuations in power generation at the WVS projects would therefore trigger adjustments in not only the Federal Base System but also the larger regional system of aggregated resources (e.g., incorporating additional generating capacity) to ensure the system is capable of supplying the demand for power, which fluctuates over the course of minutes, hours, days, months, and years.

This chapter describes the methods employed to identify how changes in generation at the WVS projects under the Alternatives would affect the adequacy and reliability of the regional power supply system absent any adjustments to existing resources. It then describes the approach used to identify and quantify costs of "replacement resources" in determining whether such investments would be needed to add capacity and maintain power system reliability at a level consistent with the NAA.

This stage of the analysis is scenario-based. It evaluates the sensitivity of the results to assumptions regarding how the system would respond to changes stemming from the WVS Action Alternatives (i.e., changes in generation at the WVS projects).

3.1 Regional Power System Reliability Methodology

Bonneville modeled regional power system reliability for the WVS PEIS alternatives using the Northwest Power and Conservation Council's (NW Council) GENeration Evaluation SYStem (GENESYS) model as described in Section 3.1.1 below. The analysis applies the GENESYS model to determine the LOLP metric (measures the likelihood of at least one power supply shortfall occurring in a future year) for the NAA and each of the Action Alternatives.

3.1.1 GENESYS

GENESYS is an economic dispatch model that uses Monte Carlo sampling to simulate short-term load uncertainty, and uncertainty in stream flows, wind, solar, and forced outages for thermal generation plants. The model performs a detailed constrained dispatch of the regulated hydropower projects in the Columbia River watershed and a simple dispatch of Pacific Northwest regional thermal plants against an extra-regional import market.

The model was developed by the NW Council, Bonneville, and other regional entities, and is used to perform studies requiring detailed hydropower dispatch for planning purposes.[11] More specifically, NW Council uses GENESYS for annual adequacy assessments, periodic regulated hydropower flow studies and periodic analysis of lost revenue due to hydropower dispatch change. The adequacy of the regional power supply is assessed probabilistically in GENESYS by evaluating any regional shortfall against NW Council's adequacy standard (i.e., a LOLP of 5 percent or less). This standard was designed to assess whether the region has sufficient resources to meet growing demand for electricity in future years. Regulated hydropower flow studies have been performed for fish passage survival and life-cycle studies, and for climate change scenarios.

For the WVS PEIS alternatives, datasets containing hydropower generation plant-specific parameters and constraints (inputs similar to those used in HYDSIM and ResSim models), thermal generation plant parameters and constraints, and other generation sources and constraints (i.e., wind and solar power plants) were input into the model. Additional inputs to the model include power demand (i.e., "loads") produced by the NW Council and assumptions regarding the availability of independent power producers and imports from outside the region.[12] The NW Council's 2017 data set was used with specific parameters and constraints for the main stem hydroelectric system updated to reflect the CRSO EIS's Preferred Alternative conditions. The Willamette Projects are hydraulically independent of the main stem FCRPS Projects and are included as hydro independents in the GENESYS studies. For each of the WVS EIS Alternatives, the GENESYS model was updated to reflect the generation of the Willamette Projects of that particular alternative.

The GENESYS model relies on Monte Carlo simulations of the system to estimate LOLP based on weather-related load uncertainty, in addition to uncertainties in stream flows, wind, solar, and forced outages for thermal generation.[13] The model performs a detailed dispatch of the regulated hydropower projects in the watershed of the Columbia River, Pacific Northwest regional thermal plants, wind, solar, along with other renewable energy resources, to determine the power imports that would be necessary to meet the load (demand) of the Pacific Northwest.

Bonneville used the GENESYS model to conduct the studies and ran 6,160 Monte Carlo simulations for each WVS PEIS alternative involving hydropower (i.e., HYDSIM results for WVS Projects), wind, and solar energy variability; forced outages on thermal plant generation; and hourly historical temperature variations (1936 to 2008). This provided the LOLP frequency (i.e.,

[11] The GENESYS model used for modeling is the classic version of GENESYS, which is available to Bonneville and the public by the NW Council as part of their 7th Power Plan (documentation in NW Council 2016). In the 8th Power Plan (in draft), the NW Council uses a new version of GENESYS which is not currently available to Bonneville or the public.
[12] Details for load descriptions are provided in NW Council 2017.
[13] In general, Monte Carlo simulation is a statistical technique that uses random events, or probability analysis, to simulate an outcome. Bonneville uses it to forecast potential regional load growth.

how many iterations out of 6,160 had instances of insufficient resources to meet the demand), but did not measure the magnitude or duration of an outage.

The reliability analyses were regional (NW-US) and were not performed for the CRS (Federal), Mid-Columbia, or Canadian systems. Because the utilities in the region can buy and sell power bilaterally with one another that is surplus to their retail load needs, the loss of generation by one entity can have adverse consequences to utilities relying on such generation. If the Federal system loses generation, Bonneville may be obligated to acquire resources to replace losses in the Federal Base System consistent with Bonneville's long-term firm power sales contracts or its customers may do so. Therefore, this analysis included identification of whether replacement resources would need to be acquired by Bonneville or its customers to serve Bonneville's firm power load obligations.

3.2 Regional Power System Reliability Results

This section presents the LOLP results for the NAA and for the Action Alternatives with comparisons to the NAA. LOLP is expressed as a percentage that reflects the probability that the WVS and the larger regional power supply is adequate to meet the region's expected load demand for electricity in a year. Higher LOLPs reflect the increased likelihood that the power system would be unable to meet demand and lower LOLPs reflect a decreased likelihood that the power system would be unable to meet demand. The LOLP is a measure of the frequency of outages but not a measure of their duration or magnitude. While LOLP reflects the adequacy of the aggregated regional power supply, individual utilities within the Pacific Northwest, such as Bonneville, face a wide range of future resource needs that are unique to them that trigger actions and/or decisions to develop, add, or acquire resources to meet their obligations.

Achieving a higher level of power system reliability (a lower LOLP) requires the development of resources to meet either load growth or as replacement for losses in existing resources. Resources are developed by either individual utilities to meet their load serving obligations or by commercial/ independent power producers that assume the risk of building resources to meet forecasted supply needs.

In 2011, the NW Council set a regional standard for LOLP to be no higher than 5 percent. That is, in roughly one of every 20 years, the region would experience one or more energy shortages (potentially blackouts). The NW Council recommends investments in the power and transmission systems until the LOLP reaches 5 percent.

3.2.1 Regional Power System Reliability Summaries

Table 3.2-1 presents the LOLP results for each Action Alternative, the NAA, and Interim Operations. Based on the modeled changes in power generation, existing load forecasts, and coal plant retirements anticipated as of 2017, the NAA would result in an LOLP of 6.5 percent in

2022. This would exceed the current NW Council target of 5 percent.[14] However, because the NW Council's target is useful regional guidance, and 6.5 percent is within the range of the Pacific Northwest (PNW) Power System LOLP in recent years, this analysis considers the 6.5 percent NAA LOLP a reasonable benchmark level during the timeframe of this analysis.

Changes in power generation anticipated from structural and operational changes specified by the alternatives may affect the LOLP of the regional power system. As identified in Table 3.2-1, the differences between the Action Alternatives and Interim Operations versus the NAA are indistinguishable (i.e., within the +/- 1 percent range of modeling accuracy) and the risk of blackouts or power shortages for all alternatives (including the NAA) is about once every 15 years. Since the WVS projects represent a small part of the overall PNW Power System and the LOLPs are not materially different from the NAA, no replacement resources are required to bring the LOLPs in alignment with the NAA.

Table 3.2-1. LOLP Results for WVS Alternatives

Alternative	LOLP (%)	LOLP Difference from No Action	Blackout(s)/Power Shortage(s) Every x Years
No Action	6.5	N/A	1 year in every 15 years
Alternative 1	6.4	-0.1	1 year in every 15 years
Alternative 2A	6.5	0	1 year in every 15 years
Alternative 2B	6.6	+0.1	1 year in every 15 years
Alternative 3A	7.0	+0.5	1 year in every 15 years
Alternative 3B	7.0	+0.5	1 year in every 15 years
Alternative 4	6.5	0	1 year in every 15 years
Interim Operations	6.8	+0.3	1 year in every 15 years
Alternative 5	6.6	+0.1	1 year in every 15 years

3.2.2 Regional Power System Reliability: Alternative Comparisons to NAA

3.2.2.1 No-Action Alternative

As noted above, Bonneville's analysis of the LOLP for the NAA is 6.5 percent for the PNW, which means that the region could experience a substantial power shortage (or recurring power shortages) roughly one in every 15 years.

The NAA LOLP does not meet the NW Council's 5 percent LOLP standard. Because the 6.5 percent NAA LOLP value is above the regional standard, regional utility planners (and potentially Bonneville if requested by its customers) should be building or acquiring new

[14] Note that LOLP is a probabilistic estimate and does not indicate magnitude or scale of potential power system outages and it is also not linear in effects, however, it is a useful metric of overall system reliability and stability. *See* NW Council Document Number 2011-14, Page 4, available at: https://www.nwcouncil.org/sites/default/files/2011_14_1.pdf.

generating resources. However, the WVS Projects' NAA LOLP of 6.5 is not substantially different than the PNW Power System LOLP in recent years. The region has accepted this higher level of LOLP over the past 5 years in absence of replacement resources, and it has become the status quo. As such, the 6.5 percent LOLP of the NAA will serve as the measure of comparison for the effects of the other WVS PEIS alternatives.

3.2.2.2 Alternative 1: Change from NAA

Bonneville estimates the LOLP for Alternative 1 is 6.4 percent for the PNW, which means there was a blackout/power shortage (or multiple blackouts) in 6.4 percent of the simulation iterations or approximately one every 15 years.

The LOLP changes from the NAA (6.5 percent) to Alternative 1 (6.4 percent) are indistinguishable (i.e., within the +/- 1 percent range of modeling accuracy); therefore, no replacement resources would be needed to return the LOLP to the NAA level.

3.2.2.3 Alternative 2A: Change from NAA

Bonneville estimates the LOLP for Alternative 2A is 6.5 percent for the PNW, which means there was a blackout/power shortage (or multiple blackouts) in 6.5 percent of the simulation iterations or approximately one loss of load event or events (i.e., power shortages resulting in blackouts or emergency actions) every 15 years.

There is no difference between the LOLP of the NAA (6.5 percent) and Alternative 2A; therefore, no replacement resources would be needed to return the LOLP to the NAA level.

3.2.2.4 Alternative 2B: Change from NAA

Bonneville estimates the LOLP for Alternative 2B is 6.6 percent for the PNW, which means there was a blackout/power shortage (or multiple blackouts) in 6.6 percent of the simulation iterations or approximately one loss of load event or events (i.e., power shortages resulting in blackouts or emergency actions) every 15 years.

The LOLP changes from the NAA (6.5 percent) to Alternative 2B (6.6 percent) are indistinguishable (i.e., within the +/- 1 percent range of modeling accuracy); therefore, no replacement resources would be needed to return the LOLP to the NAA level.

3.2.2.5 Alternative 3A: Change from NAA

Bonneville estimates the LOLP for Alternative 3A is 7.0 percent for the PNW, which means there was an outage (or multiple outages) in 7.0 percent of the simulation iterations or approximately one loss of load event or events (i.e., power shortages resulting in blackouts or emergency actions) every 15 years.

The LOLP changes from the NAA (6.5 percent) to Alternative 3A (7.0 percent) are negligible and are indistinguishable (i.e., within the +/- 1 percent range of modeling accuracy); therefore, no replacement resources would be needed to return the LOLP to the NAA level.

3.2.2.6 Alternative 3B: Change from NAA

Bonneville estimates the LOLP for Alternative 3B is 7.0 percent for the PNW, which means there was an outage (or multiple outages) in 7.0 percent of the simulation iterations or approximately one loss of load event or events (i.e., power shortages resulting in blackouts or emergency actions) every 15 years.

The LOLP changes from the NAA (6.5 percent) to Alternative 3B (7.0 percent) are indistinguishable (i.e., within the +/- 1 percent range of modeling accuracy); therefore, no replacement resources would be needed to return the LOLP to the NAA level.

3.2.2.7 Alternative 4: Change from NAA

Bonneville estimates the LOLP for Alternative 4 is 6.5 percent for the PNW, which means there was an outage (or multiple outages) in 6.5 percent of the simulation iterations or approximately one loss of load event or events (i.e., power shortages resulting in blackouts or emergency actions) every 15 years.

There is no difference between the LOLP of the NAA (6.5 percent) and Alternative 4; therefore, no replacement resources would be needed to return the LOLP to the NAA level.

3.2.2.8 Interim Operations: Change from NAA

Bonneville estimates the LOLP for Interim Operations is 6.8 percent for the PNW, which means there was an outage (or multiple outages) in 6.8 percent of the simulation iterations or approximately one loss of load event or events (i.e., power shortages resulting in blackouts or emergency actions) every 15 years.

The LOLP changes from the NAA (6.5 percent) to Interim Operations (6.8 percent) are indistinguishable (i.e., within the +/- 1 percent range of modeling accuracy); therefore, no replacement resources would be needed to return the LOLP to the NAA level.

3.2.2.9 Alternative 5: Change from NAA

As there is no difference in average generation, Bonneville estimates the LOLP for Alternative 5, would be similar to Alternative 2B, which is 6.6 percent for the PNW. This means a blackout/power shortage (or multiple blackouts) would occur in 6.6 percent of the simulation iterations or approximately one loss of load event (i.e., power shortage resulting in blackouts or emergency actions) every 15 years.

The LOLP changes from the NAA (6.5 percent) to Alternative 5 (6.6 percent) are indistinguishable (i.e., within the +/- 1 percent range of modeling accuracy); therefore, no replacement resources would be needed to return the LOLP to the NAA level.

4. TRANSMISSION PATHS INCREMENTAL ANALYSIS

This chapter describes the methodology, data, and results of the transmission paths incremental analysis estimating the incremental power flow change on Bonneville Transmission Network Paths between the NAA and Action Alternatives during multiple seasons as a result of generation output changes at the Federal WVS projects with hydropower facilities (Detroit, Big Cliff, Cougar, Foster, Hills Creek, Lookout Point, and Dexter).

The purpose of the transmission paths incremental analysis was to evaluate expected changes in power flows that may occur under each of the Alternatives.

4.1 Transmission Paths Methodology

Bonneville Transmission Services' September 2021 Long Term Available Transfer Capability (LT ATC) power flow base cases were used as the starting point for loads, resource dispatch, and transmission topology. These cases estimate utilization of Bonneville's Long Term Firm (LTF) transmission service commitments for a ten-year planning horizon under "All Lines in Service" conditions in selected seasonal conditions that may stress the transmission system. These cases simulate snapshots for 2031.[15] A single power flow case was used to represent each of the following seasonal conditions:

- Winter Peak (January), Upper Columbia stress zone;
- Spring Off-peak (May), Lower Snake stress zone; and
- Summer Peak (August), Upper Columbia stress zone.

NAA reference power flow cases were created by adjusting the output of each Willamette project to match the monthly average energy over 73 years of historical hydrology runoffs provided in the HYDSIM outputs for the three respective months listed above.

The LOLP analysis results (in Section 3 of this appendix) were also used as the basis for the assumptions to inform the case for the alternatives. Because new replacement resources would not be needed to return the LOLP to the NAA level, generation decreases at the Willamette projects would be balanced by increases at either the Upper Columbia or Lower Snake generation facilities as discussed below.

The differences in power flows were calculated on Bonneville Transmission Network Paths between the NAA reference case and each EIS Alternative case for each of the three seasonal conditions (i.e., Winter Peak, Spring-Off-peak, and Summer Peak).

[15] WECC produces power flow models for the Western Interconnect power system for different planning horizons. A 10-year case is the farthest case WECC produces.

4.2 Transmission Paths Results

This section provides the transmission power flow results from the NAA and for the Action Alternatives with comparisons to the NAA.

4.2.1 Transmission Paths Summaries

Tables 4.2-1 through 4.2-3 represent the seasonal MW values for the WVS projects generation outputs and the Bonneville Transmission Network Paths and comparison of the changes in power flows between the NAA and the Action Alternatives.

With the NAA as the reference case, incremental power flow increases greater than 25 MW for Alternative 3A and Alternative 3B occurred on the Cross Cascades South path for all seasons. This results from the decreases in the Willamette Valley generation for those two alternatives with generation being replaced at either Upper Columbia (Winter and/or Summer peak cases) or Lower Snake (Spring Off-Peak case) generation facilities. Specific to only the Winter and Summer peak seasons for Alternatives 3A and 3B, incremental flow increases greater than 25 MW also occurred on North of Hanford due to the shift in generation from Willamette Valley to Upper Columbia. The Alternatives 3A and 3B generation values for the Spring Off-peak season reflected the highest MW difference from the NAA; therefore, that season generally yielded the largest magnitude change in flows across Bonneville's network flowgates in comparison to the other two seasonal cases. For the Spring Off-Peak case, the largest change in flow of 118 MW occurred on the West of Lower Monumental path with other noticeable changes (greater than 25 MW) on Cross Cascades South, West of John Day, West of McNary, and West of Slatt due to the shift of generation from Willamette Valley to Lower Snake generation facilities. For Alternatives 3A and 3B, the Summer Peak case resulted in the least amount of megawatt differences across Bonneville Transmission Network Paths.

Alternative 2A and 2B for the Winter Peak case were the midpoint between Alternatives 3A and 3B, and Alternative 1 and Alternative 4. For the Spring Off-Peak, the results were a bit higher than Alternative 4 results, which had a slightly different generation output profile than Alternative 2A. For the Summer Peak case, Alternative 2A had the least amount of impacts on Bonneville Transmission Network Paths and Generation re-dispatch with respect to the NAA.

Generally, the network flow changes for all Action Alternatives represent little to no impact for most paths. As discussed above, there is moderate impact on the congested Cross Cascades South path for some Action Alternatives. This path supplies power from generators east of the Cascade Range to load centers in Portland and areas to the south. While some capacity on the path remains, decreases in generation for Alternatives 2A, 2B, 3A, and 3B would have an incremental impact and may lead to minor cost increases for ratepayers and minor complications for meeting state climate goals.

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Table 4.2-1. Winter Peak Case (January); FCRPS Upper Columbia Generation Facilities Replacement Generation

Generation Outputs (MW)	NAA	Alt 1	Alt 1 vs. NAA	Alt 2A	Alt 2A vs. NAA	Alt 2B	Alt 2B vs. NAA	Alt 3A	Alt 3A vs. NAA	Alt 3B	Alt 3B vs. NAA	Alt 4	Alt 4 vs. NAA	Int. Ops.	Int. Ops vs. NAA	Alt 5 (PA)	Alt5 vs. NAA (PA vs NAA)
Detroit	56.9	56.2	-0.7	56	-0.9	56	-0.9	39.8	-17.1	39.5	-17.4	56	-0.9	28.8	-28.1	56	-0.9
Big Cliff	12.9	12.8	-0.1	12.8	-0.1	12.8	-0.1	11	-1.9	10.9	-2	12.8	-0.1	12.8	-0.1	12.8	-0.1
Cougar	17.6	17.7	0.1	16.5	-1.1	9.2	-8.4	17.5	-0.1	9.1	-8.5	16.6	-1	10.7	-6.9	9.2	-8.4
Green Peter	45.5	45.5	0	27.0	-18.5	27	-18.5	26.9	-18.6	28.5	-17	45.3	-0.2	27.1	-18.4	27	-18.5
Foster	17.6	15.4	-2.2	12.2	-5.4	12.3	-5.3	14.4	-3.2	14.6	-3	16.1	-1.5	14.2	-3.4	12.3	-5.3
Hills Creek	22	21.9	-0.1	21.1	-0.9	21.3	-0.7	20.5	-1.5	21.3	-0.7	21.3	-0.7	19.2	-2.8	21.3	-0.7
Lookout Pt	49.5	47.3	-2.2	46.9	-2.6	47.5	-2	33.4	-16.1	31.8	-17.7	46.9	-2.6	34.5	-15.0	47.5	-2
Dexter	12.9	12.8	-0.1	12.8	-0.1	12.7	-0.2	11.3	-1.6	11.3	-1.6	12.8	-0.1	11.3	-1.6	12.7	-0.2
Combined WVS Projects	**234.9**	**229.6**	**-5.3**	**205.3**	**-29.6**	**198.8**	**-36.1**	**174.8**	**-60.1**	**167**	**-67.9**	**227.8**	**-7.1**	158.7	**-76.2**	**198.8**	**-36.1**
Bonneville Transmission Network Paths (MW)	**NAA**	**Alt 1**	**Alt 1 vs. NAA**	**Alt 2A**	**Alt 2A vs. NAA**	**Alt 2B**	**Alt 2B vs. NAA**	**Alt 3A**	**Alt 3A vs. NAA**	**Alt 3B**	**Alt 3B vs. NAA**	**Alt 4**	**Alt 4 vs. NAA**	**Int. Ops.**	**Int. Ops.vs. NAA**	**Alt5 (PA)**	**Alt5 vs. NAA PA vs. NAA**
Cross Cascades North E>W	9445.7	9446.9	1.2	9452.8	7.1	9454.2	8.5	9459.8	14.1	9461.3	15.6	9447.2	1.5	9463.2	17.5	9454.2	8.5
Cross Cascades South E>W	6475.5	6478.7	3.2	6493.9	18.4	6497.4	21.9	6512.7	37.2	6516.9	41.4	6479.7	4.2	6522.5	47.0	6497.4	21.9
North of Echo Lake S>N	2362.6	2362.2	-0.4	2360.2	-2.4	2359.8	-2.8	2357.9	-4.7	2357.3	-5.3	2362.1	-0.5	2356.7	-5.9	2359.8	-2.8
North OF Hanford N>S	-1150.9	-1147.9	3	-1133.2	17.7	-1129.5	21.4	-1115	35.9	-1110.5	40.4	-1146.8	4.1	-1105.8	45.1	-1129.5	21.4
Paul to Allston N>S	245.6	246.5	0.9	251.3	5.7	252.4	6.8	256.9	11.3	258.2	12.6	246.8	1.2	259.7	14.1	252.4	6.8
Raver to Paul N>S	725.3	726	0.7	729.8	4.5	730.7	5.4	734.2	8.9	735.2	9.9	726.3	1	736.4	11.1	730.7	5.4

Generation Outputs (MW)	NAA	Alt 1	Alt 1 vs. NAA	Alt 2A	Alt 2A vs. NAA	Alt 2B	Alt 2B vs. NAA	Alt 3A	Alt 3A vs. NAA	Alt 3B	Alt 3B vs. NAA	Alt 4	Alt 4 vs. NAA	Int. Ops.	Int. Ops vs. NAA	Alt 5 (PA)	Alt5 vs. NAA (PA vs NAA)
South of Allston N>S	1183	1184.2	1.2	1189.9	6.9	1191.3	8.3	1196.6	13.6	1198.2	15.2	1184.5	1.5	1200.0	17.0	1191.3	8.3
South of Custer N>S	-1371	-1371	0	-1370.8	0.2	-1370.8	0.2	-1370.7	0.3	-1370.7	0.3	-1370.9	0.1	-1370.7	0.3	-1370.8	0.2
West of Hatwai E>W	908.5	908.3	-0.2	907.1	-1.4	906.8	-1.7	905.6	-2.9	905.2	-3.3	908.2	-0.3	904.9	-3.6	906.8	-1.7
West of John Day E>W	3358.6	3359.3	0.7	3362.8	4.2	3363.4	4.8	3366.5	7.9	3367.2	8.6	3359.5	0.9	3368.6	10.0	3363.4	4.8
West of Lower Monumental E>W	2420.9	2421.2	0.3	2422.9	2.0	2423.3	2.4	2425	4.1	2425.4	4.5	2421.3	0.4	2426.0	5.1	2423.3	2.4
West of McNary E>W	2389.1	2389.9	0.8	2393.4	4.3	2394.3	5.2	2397.7	8.6	2398.8	9.7	2390.1	1	2399.9	10.8	2394.3	5.2
West of Slatt E>W	2679.7	2680.6	0.9	2685.1	5.4	2686.3	6.6	2690.8	11.1	2692.3	12.6	2681	1.3	2693.7	14.0	2686.3	6.6

Table 4.2-2. Spring Off-peak Case (May); FCRPS Lower Snake Generation Facilities Replacement Generation

Gen Outputs (MW)	NAA	Alt 1	Alt 1 vs. NAA	Alt 2A	Alt 2A vs. NAA	Alt 2B	Alt 2B vs. NAA	Alt 3A	Alt 3A vs. NAA	Alt 3B	Alt 3B vs. NAA	Alt 4	Alt 4 vs. NAA	Int. Ops.	Int. Ops vs. NAA	ALT 5	Alt 5 vs. NAA
Detroit	59.8	63.2	3.4	34.1	-25.7	62.4	2.6	0	-59.8	27.5	-32.3	62.3	2.5	27.8	-32.0	62.4	2.6
Big Cliff	12.6	12.8	0.2	8.0	-4.6	12.7	0.1	0	-12.6	0	-12.6	12.7	0.1	12.7	0.1	12.7	0.1
Cougar	20.3	16.8	-3.5	10.8	-9.5	0	-20.3	18.4	-1.9	0	-20.3	18.1	-2.2	9.6	-10.7	0	-20.3
Green Peter	28.6	28.8	0.2	22.1	-6.5	11.6	-17	11.6	-17	0	-28.6	11.4	-17.2	31.5	2.9	11.6	-17
Foster	9.5	11.2	1.7	10.1	0.6	12.3	2.8	9.5	0	9.4	-0.1	11.6	2.1	6.4	-3.1	12.3	2.8
Hills Creek	24.1	21	-3.1	12.5	-11.6	22.6	-1.5	12.2	-11.9	21.1	-3	22.6	-1.5	17.4	-6.7	22.6	-1.5
Lookout Pt	54.9	49	-5.9	26.6	-28.3	50.6	-4.3	4.7	-50.2	24.2	-30.7	50.1	-4.8	21.9	-33.0	50.6	-4.3

Dexter	11.7	10.1	-1.6	6.5	-5.2	10.5	-1.2	0	-11.7	0	-11.7	10.4	-1.3	5.8	-5.9	10.5	-1.2
Combined WVS Projects	**221.5**	**212.9**	**-8.6**	**130.7**	**-90.8**	**182.7**	**-38.8**	**56.4**	**-165.1**	**82.2**	**-139.3**	**199.2**	**-22.3**	**133.1**	**-88.4**	**182.7**	**-38.8**
Bonneville Transmission Network Paths(MW)	**NAA**	**Alt 1**	**Alt 1 vs. NAA**	**Alt 2A**	**Alt 2A vs. NAA**	**Alt 2B**	**Alt 2B vs. NAA**	**Alt 3A**	**Alt 3A vs. NAA**	**Alt 3B**	**Alt 3B vs. NAA**	**Alt 4**	**Alt 4 vs. NAA**	**Int. Ops.**	**Int. Ops. vs. NAA**	**Alt 5**	**ALT 5 vs. NAA**
Cross Cascades North E>W	5652.7	5653.7	1	5666.9	14.2	5657.5	4.8	5676.9	24.2	5673.5	20.8	5655.7	3	5666.5	13.8	5657.5	4.8
Cross Cascades South E>W	4100.5	4105.7	5.2	4161.8	61.3	4125.6	25.1	4214.2	113.7	4195.3	94.8	4115.5	15	4160.3	59.8	4125.6	25.1
North of Echo Lake S>N	1297.0	1296.9	-0.1	1297.4	0.4	1296.5	-0.5	1296.4	-0.6	1296.7	-0.3	1296.7	-0.3	1297.4	0.4	1296.5	-0.5
North OF Hanford N>S	-333.8	-334.1	-0.3	-338.5	-4.7	-335.5	-1.7	-342.2	-8.4	-341	-7.2	-334.9	-1.1	-338.4	-4.6	-335.5	-1.7
Paul to Allston N>S	613.6	614.5	0.9	623.6	10.0	617.9	4.3	632.3	18.7	629.3	15.7	616.2	2.6	623.2	9.6	617.9	4.3
Raver to Paul N>S	881.3	882.0	0.7	889.4	8.1	884.8	3.5	896.5	15.2	894.1	12.8	883.5	2.2	889.1	7.8	884.8	3.5
South of Allston N>S	732.1	733.9	1.8	743.9	11.8	737.2	5.1	754.4	22.3	750.8	18.7	735.3	3.2	743.5	11.4	737.2	5.1
South of Custer N>S	-1368.3	-1368.2	0.1	-1370.2	-1.9	-1367.9	0.4	-1369.4	-1.1	-1369.7	-1.4	-1368.1	0.2	-1370.2	-1.9	-1367.9	0.4
West of Hatwai E>W	3088.1	3087.7	-0.4	3086.2	-1.9	3086.3	-1.8	3082.5	-5.6	3083.8	-4.3	3087	-1.1	3086.4	-1.7	3086.3	-1.8
West of John Day E>W	2997.4	2998.6	1.2	3014.3	16.9	3004.4	7	3029.1	31.7	3024	26.6	3001.7	4.3	3013.7	16.3	3004.4	7
West of Lower Monumental E>W	3728.5	3734.3	5.8	3793.0	64.5	3754.7	26.2	3846.7	118.2	3827.6	99.1	3744.3	15.8	3791.3	62.8	3754.7	26.2
West of McNary E>W	2305.9	2308.4	2.5	2334.3	28.4	2317.5	11.6	2358.2	52.3	2349.6	43.7	2312.9	7	2333.6	27.7	2317.5	11.6
West of Slatt E>W	2833.7	2836.0	2.3	2857.7	24.0	2843.6	9.9	2877.7	44	2870.5	36.8	2839.6	5.9	2857.1	23.4	2843.6	9.9

Table 4.2-3. Summer Peak Case (August); FCRPS Upper Columbia Generation Facilities Replacement Generation

Gen Outputs (MW)	NAA	Alt 1	Alt 1 vs. NAA	Alt 2A	Alt 2A vs. NAA	Alt 2B	Alt 2B vs. NAA	Alt 3A	Alt 3A vs. NAA	Alt 3B	Alt 3B vs. NAA	Alt 4	Alt 4 vs. NAA	Int. Ops.	Int. Ops. vs. NAA	Alt 5	Alt 5 vs. NAA
Detroit	13.6	27.2	13.6	31.4	17.8	31.8	18.2	1.2	-12.4	25.3	11.7	31.8	18.2	18.9	5.3	31.8	18.2
Big Cliff	6	6	0	7.6	1.6	7.7	1.7	4.7	-1.3	8.1	2.1	7.7	1.7	7.7	1.7	7.7	1.7
Cougar	16.1	15.7	-0.4	14.4	-1.7	0.5	-15.6	5.7	-10.4	0.5	-15.6	14.7	-1.4	13.3	-2.8	0.5	-15.6
Green Peter	15.9	14.1	-1.8	16.5	0.6	14.5	-1.4	14.5	-1.4	1.1	-14.8	14.8	-1.1	20.8	4.9	14.5	-1.4
Foster	5.9	1	-4.9	5.3	-0.6	5.4	-0.5	9	3.1	3.9	-2	5.8	-0.1	3.5	-2.4	5.4	-0.5
Hills Creek	17	19.8	2.8	15.7	-1.3	17.9	0.9	19.2	2.2	6.4	-10.6	16.2	-0.8	17.1	0.1	17.9	0.9
Lookout Pt	33	40.8	7.8	31.0	-2.0	34.2	1.2	8.7	-24.3	17.8	-15.2	31	-2	10.4	-22.6	34.2	1.2

Dexter	8	9.9	1.9	7.6	-0.4	8.3	0.3	4.9	-3.1	8	0	7.5	-0.5	7.2	-0.8	8.3	0.3
Combined WVS Projects	**115.5**	**134.5**	**19**	**129.6**	**14.1**	**120.3**	**4.8**	**67.9**	**-47.6**	**71.1**	**-44.4**	**129.5**	**14**	**98.8**	**-16.7**	**120.3**	**4.8**
Bonneville Transmission Network Paths(MW)	**NAA**	**Alt 1**	**Alt 1 vs. NAA**	**Alt 2A**	**Alt 2A vs. NAA**	**Alt 2B**	**Alt 2B vs. NAA**	**Alt 3A**	**Alt 3A vs. NAA**	**Alt 3B**	**Alt 3B vs. NAA**	**Alt 4**	**Alt 4 vs. NAA**	**Int. Ops.**	**Int. Ops. vs. NAA**	**Alt 5**	**Alt 5 vs. NAA**
Cross Cascades North E>W	5327	5322.6	-4.4	5317.3	-9.7	5325.6	-1.4	5338.1	11.1	5337.6	10.6	5323.6	-3.4	5330.8	3.8	5325.6	-1.4
Cross Cascades South E>W	5862.9	5851.3	-11.6	5836.6	-26.3	5858.6	-4.3	5891.2	28.3	5888.5	25.6	5853.5	-9.4	5872.1	9.2	5858.6	-4.3
North of Echo Lake S>N	14.9	16.3	1.4	18.0	3.1	15.3	0.4	11.2	-3.7	11.4	-3.5	16	1.1	13.6	-1.3	15.3	0.4
North OF Hanford N>S	2478.8	2467.3	-11.5	2454.4	-24.4	2475.5	-3.3	2507.7	28.9	2505.9	27.1	2470.3	-8.5	2489.1	10.3	2475.5	-3.3
Paul to Allston N>S	1441.3	1437.9	-3.4	1433.8	-7.5	1440.2	-1.1	1450	8.7	1449.6	8.3	1438.7	-2.6	1444.3	3.0	1440.2	-1.1
Raver to Paul N>S	1270.8	1268.1	-2.7	1264.8	-6.0	1269.9	-0.9	1277.7	6.9	1277.4	6.6	1268.7	-2.1	1273.2	2.4	1269.9	-0.9
South of Allston N>S	2525.1	2521.9	-3.2	2516.1	-9.0	2523.8	-1.3	2535.4	10.3	2534	8.9	2522.4	-2.7	2528.7	3.6	2523.8	-1.3
South of Custer N>S	1088.4	1088.5	0.1	1088.5	0.1	1088.4	0	1088.4	0	1088.4	0	1088.5	0.1	1088.4	0.0	1088.4	0
West of Hatwai E>W	1100.2	1101	0.8	1101.8	1.6	1100.3	0.1	1098.1	-2.1	1098.2	-2	1100.7	0.5	1099.4	-0.8	1100.3	0.1
West of John Day E>W	2619.3	2617.1	-2.2	2613.4	-5.9	2618.2	-1.1	2624.9	5.6	2624.4	5.1	2617.2	-2.1	2620.8	1.5	2618.2	-1.1
West of Lower Monumental E>W	2108.1	2106.8	-1.3	2105.2	-2.9	2107.7	-0.4	2111.4	3.3	2111.2	3.1	2107.1	-1	2109.3	1.2	2107.7	-0.4
West of McNary E>W	2411.8	2409	-2.8	2405.8	-6.0	2410.9	-0.9	2418.6	6.8	2418.1	6.3	2409.6	-2.2	2414.1	2.3	2410.9	-0.9
West of Slatt E>W	3363.6	3360	-3.6	3356.3	-7.3	3362.7	-0.9	3372.7	9.1	3371.8	8.2	3361.1	-2.5	3367.0	3.4	3362.7	-0.9

4.2.2 Transmission Paths: Action Alternative Comparisons to NAA

4.2.2.1 No-Action Alternative

Generation outputs at WVS projects under the NAA vary seasonally ranging from a total of 234.9 MW in the Winter Peak, 221.5 MW in the Spring Off-peak, and 115.5 MW in the Summer Peak cases as shown in Table 4.2-1 through Table 4.2-3. Power flows through key Bonneville Network Paths in these base cases ranged from -1371 MW and -1368.3 at South of Custer to 9445.7 and 5652.7 MW at Cross Cascades North during the Winter Peak and Spring Off-peak cases respectively; and from 14.9 MW at North of Echo Lake and 5862.9 MW at Cross Cascades South during the Summer Peak case.

4.2.2.2 Alternative 1: Change from NAA

With the NAA as the reference case, most incremental changes on Bonneville Transmission Network Paths for Alternative 1 were less than +/-10 MW under all seasonal cases as shown in Table 4.2-1 through Table 4.2-3. The largest incremental changes on Bonneville Transmission Network Paths for Alternative 1 occurred under the Summer Peak case (Table 4.2-3), specifically Cross Cascades South and North of Hanford paths (-11.6 MW and -11.5 MW, respectively), which can be attributed to the 19 MW increase in Willamette Valley generation compared to the NAA.

4.2.2.3 Alternative 2A: Change from NAA

With the NAA as the reference case, most incremental changes on Bonneville Transmission Network Paths for Alternative 2A under all seasonal cases were less than +/- 25 MW as shown in Table 4.2-1 through Table 4.2-3. The largest incremental changes on Bonneville Transmission Network Paths for Alternative 2A occurred under the Spring Off-peak case at the West of Lower Monumental (64.5 MW) and Cross Cascades South (61.3 MW) paths as shown in Table 4.2-2, which can be attributed to the 90.8 MW decrease in Willamette Valley generation in this seasonal case with generation being replaced at Lower Snake generation facilities.

4.2.2.4 Alternative 2B: Change from NAA

With the NAA as the reference case, most incremental changes on Bonneville Transmission Network Paths for Alternative 2B under all seasonal cases were less than +/- 25 MW as shown in Table 4.2-1 through Table 4.2-3. The largest incremental changes on Bonneville Transmission Network Paths for Alternative 2B occurred under the Spring Off-peak case at the West of Lower Monumental (26.2 MW) and Cross Cascades South (25.1 MW) paths as shown in Table 4.2-2, which can be attributed to the 38.8 MW decrease in Willamette Valley generation in this seasonal case with generation being replaced at Lower Snake generation facilities.

4.2.2.5 Alternative 3A: Change from NAA

With the NAA as the reference case, most incremental changes on Bonneville Transmission Network Paths for Alternative 3A under all seasonal cases were less than +/- 25 MW as shown in Table 4.2-1 through Table 4.2-3. The largest incremental changes on Bonneville Transmission Network Paths for Alternative 3A occurred under the Spring Off-peak case (Table 4.2-2), specifically Cross Cascades South and West of Lower Monumental paths (-113.7 MW and -118.2 MW, respectively). Other locations with greater than 25 MW differences from the NAA include West of John Day (31.7 MW), West of McNary (52.3 MW), and West of Slatt (44 MW) under the Spring Off-peak case and the Cross Cascades South (37.2 MW and 28.3 MW) and North of Hanford (25.2 MW and 28.9 MW) under the Winter and Summer Peak cases, respectively. These noted differences can be attributed to decreases in Willamette Valley generation under all seasonal cases (ranging between 47.6 MW and 165.1 MW) with generation being replaced at either Upper Columbia (Winter and/or Summer peak cases) or Lower Snake (Spring Off-Peak case) generation facilities.

4.2.2.6 Alternative 3B: Change from NAA

With the NAA as the reference case, many incremental changes on Bonneville Transmission Network Paths for Alternative 3A under all seasonal cases were less than +/- 25 MW as shown in Table 4.2-1 through Table 4.2-3. The largest incremental changes on Bonneville Transmission Network Paths for Alternative 3B occurred under the Spring Off-peak case as shown in Table 4.2-2, specifically Cross Cascades South and West of Lower Monumental paths (-94.8 MW and -99.1 MW, respectively). Other locations with greater than 25 MW differences from the NAA include West of John Day (26.6 MW), West of McNary (43.7 MW), and West of Slatt (36.8 MW) under the Spring Off-peak case and Cross Cascades South (41.4) and North of Hanford (40.4 MW) under the Winter Peak case as shown in Table 4.2.2 and Table 4.2.1, respectively. These noted differences can be attributed to the decreases in the Willamette Valley generation under all seasonal cases (ranging between 47.6 MW and 165.1 MW) with generation being replaced at either Upper Columbia (Winter and/or Summer peak cases) or Lower Snake (Spring Off-Peak case) generation facilities.

4.2.2.7 Alternative 4: Change from NAA

With the NAA as the reference case, most incremental changes on Bonneville Transmission Network Paths for Alternative 4 were less than +/-10 MW as shown in Table 4.2-1 through Table 4.2-3. The largest incremental changes on Bonneville Transmission Network Paths for Alternative 4 occurred under the Spring Off-peak case (Table 4.2-23), specifically Cross Cascades South and West of Lower Monumental paths (15 MW and 15.8 MW, respectively), which can be attributed to the 14 MW increase in Willamette Valley generation compared to the NAA.

4.2.2.8 Interim Operations: Change from NAA

With the NAA as the reference case, many incremental changes on Bonneville Transmission Network Paths for Interim Operations under all seasonal cases were less than +/- 25 MW as shown in Table 4.2-1 through Table 4.2-3. The largest incremental changes on Bonneville Transmission Network Paths for the Interim Operations case occurred under the Spring Off-peak case as shown in Table 4.2-2, specifically Cross Cascades South and West of Lower Monumental paths (59.8 MW and 62.8 MW, respectively). Other locations with greater than 25

MW differences from the NAA include West of McNary (27.7 MW) under the Spring Off-peak case and Cross Cascades South (47.0) and North of Hanford (45.1 MW) under the Winter Peak case as shown in Table 4.2.2 and Table 4.2.1, respectively. These noted differences can be attributed to the decreases in the Willamette Valley generation under all seasonal cases (ranging between 16.7 MW and 88.4 MW) with generation being replaced at either Upper Columbia (Winter and/or Summer peak cases) or Lower Snake (Spring Off-Peak case) generation facilities.

4.2.2.9 Alternative 5: Change from NAA

Alternative 5 generation impact would be almost identical to Alternative 2B. The resulting impact on network paths was less than 0.1MW. With the NAA as the reference case, most incremental changes on Bonneville Transmission Network Paths for Alternative 5 under all seasonal cases were less than +/- 25 MW as shown in Table 4.2-1 through Table 4.2-3. The largest incremental changes on Bonneville Transmission Network Paths for Alternative 5 occurred under the Spring Off-peak case at the West of Lower Monumental (26.2 MW) and Cross Cascades South (25.1 MW) paths as shown in Table 4.2-2, which can be attributed to the 38.8 MW decrease in Willamette Valley generation in this seasonal case with generation being replaced at Lower Snake generation facilities.

5. ECONOMIC VIABILITY OF POWER GENERATION

To determine the long-term financial viability of power operations at Willamette Valley projects, the NPV and LCOG are analyzed under each Action Alternative. The analysis considers the Bonneville direct funded capital, operations, and maintenance programs as well as the structural and operational measures identified in the Action Alternatives. Costs and generation are forecast over a 30-year study period, consistent with typical economic analyses for investments in the FCRPS.

5.1 Power Generation Economic Analyses Methodologies

Bonneville is obligated to first provide contracted preference customers the opportunity to purchase power generation at the Tier 1 preference rate. Once Bonneville's Tier 1 obligations are fulfilled, Bonneville can then sell surplus energy in secondary markets. Through the end of Bonneville's current contract period with its customers in 2028, a reasonable estimate of the revenue produced by the WVS projects under each Action Alternative during this period can be based on the assumption that power generation at critical water is valued at Tier 1 rates and generation in excess of critical water is valued at Mid-Columbia (Mid-C) market price forecasts. Since post-2028 contractual conditions are not yet clear, Tier 1 rates were not applied during this period and instead all energy was valued at the forecasted Mid-Columbia market price from 2029 through the end of the 30-year study period.

Given the LOLP analysis in Section 3 indicates replacement resources would not be needed to return the LOLP to the NAA level under any of the Action Alternatives, the forecasted market value of generation from the facilities was considered a reasonable assumption to use for post-2028 revenue estimates. The assumption is that differences in generation under the Alternatives would result in either lost secondary sales opportunities or forced market purchases but no long-term acquisitions would be required. As a result, the Mid-Columbia market price is the most representative value available for post-2028.

Figure 5.1-1 presents the framework for the economic analyses. Bonneville uses HYDSIM (Section 2.1.1) and AURORA (Section 5.1.1) models to produce a range of outputs for generation and energy pricing, respectively, that vary by water year. As noted previously, the AURORA model employs a Monte Carlo simulation to generate a robust distribution of potential future states governing the wholesale energy market in the Pacific Northwest. Joining the generation and wholesale market price forecasts on common water years allows for the construction of a distribution of revenue streams associated with each Willamette Valley project.

Estimated revenue at each project was then compared with the long-term cost to sustain the projects identified in the 2024 FCRPS Strategic Asset Management Plan (SAMP) plus any structural measures contained within the Action Alternatives. Finally, these net revenues were discounted to arrive at a distribution of NPVs and LCOGs.

5.1.1 Aurora

AURORA is a production cost model, developed by Energy Exemplar, Ltd Pty., used by hundreds of utilities globally to forecast short- and long-term electricity prices. Given model inputs (resource build, load forecast, fuel cost, etc.), AURORA produces a price forecast by calculating the least cost solution of meeting system-wide load on an hourly basis, subject to a number of operating constraints. The cost of producing and delivering an additional unit of energy to a location in the system is assumed to approximate the price at that location. Bonneville uses AURORA to create price distributions by using Monte Carlo sampling of projected loads, hydro generation, gas prices, transmission capacity, wind generation, and Columbia Generating Station (CGS) capability. Bonneville also uses the AURORA model to produce a range of price forecasts by year, month, and water year. Standard AURORA runs consist of 3200 iterations (80 Water Years and 40 iterations per Water Year) that vary loads, hydro generation, gas prices, transmission capability, wind generation, and Columbia Generating Station availability to produce a distribution of price forecasts. However, the most recent long-term forecast had 630 iterations due to modeling changes that resulted in longer run times.

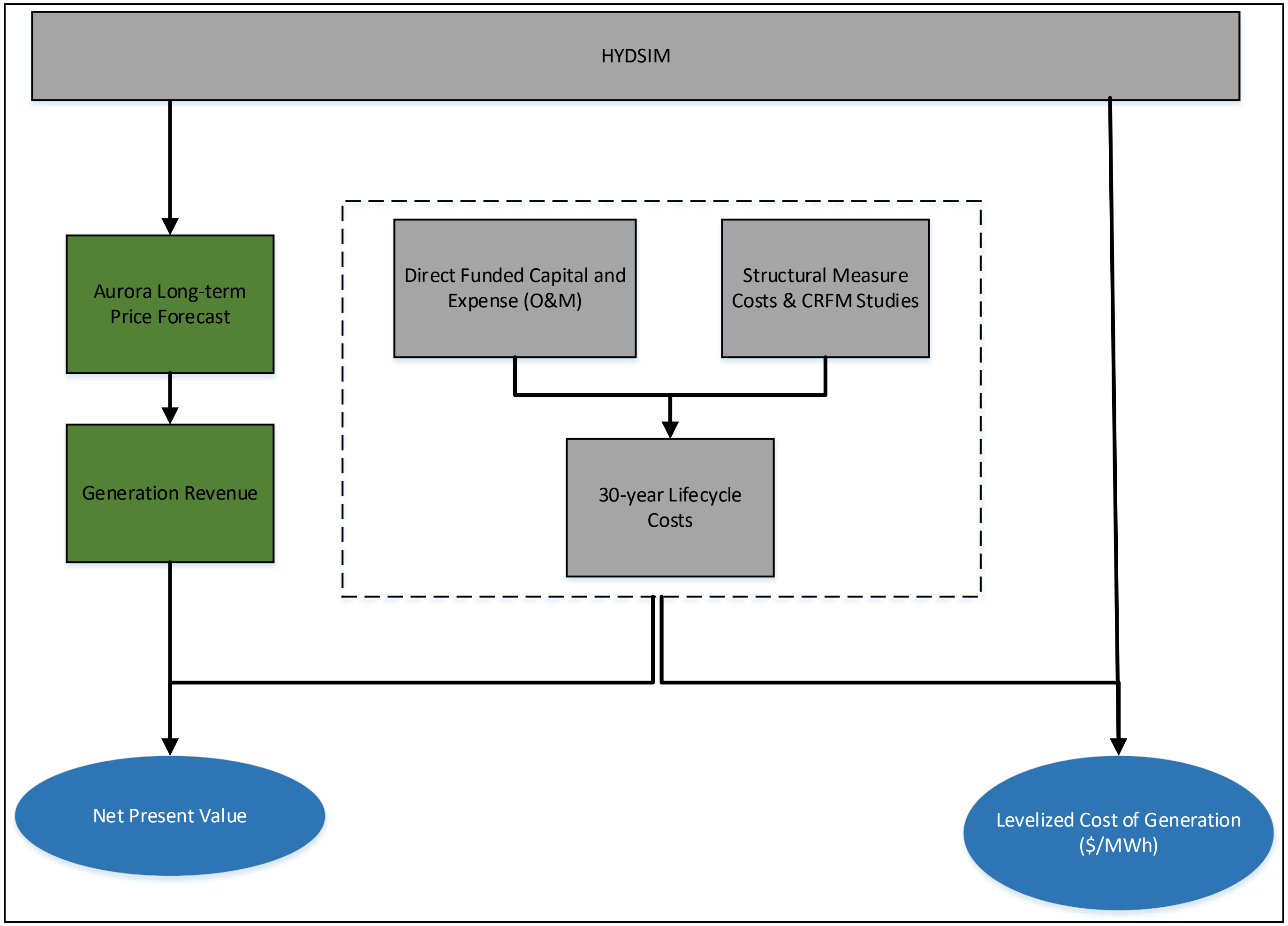

Figure 5.1-1. Analytical Approach for Evaluating Power Generation Economic Effects of the WVS Action Alternatives

Notes: HYDSIM (Generation by month, 73 Water Years); Aurora Long-term Price Forecast (630 iterations correlated with 73 Water Years); Direct Funded Capital and Expense (O&M) Forecasts (2024 SAMP and USACE' budget submissions used in support of the BP-26 Integrated Program Review); and Generation Revenue, NPV, and LCOG (630 iterations each)**.**

5.1.2 Generation Revenue

Section 2.2.1 describes how generation for each Action Alternative was modeled using HYDSIM to produce expected monthly generation for each facility across 73 water years from 1936 to 2008. To calculate generation revenue, the HYDSIM modeling results were correlated with forward looking energy prices. The long-term Mid-Columbia energy market price forecast includes modeled energy prices from 2025 through 2044 with subsequent years escalated at the rate of inflation (2.1 percent annual average). Each year includes a distribution of energy prices derived through Monte Carlo simulation as described in 5.1.1. Monthly generation amounts for each project are matched with each of the 630 iterations of monthly price forecasts for a 30-year period to produce a 30-year value of generation.

5.1.3 30-year Lifecycle Costs[16]

5.1.3.1 Direct Funded Capital and Expense (Operations and Maintenance) Costs

Direct funded capital forecasts were sourced from the 2024 FCRPS Strategic Asset Management Plan (SAMP; Bonneville 2024). The SAMP is produced every two years in support of BPA's Integrated Program Review (IPR) process to set capital and expense budgets. The SAMP analysis produces a 50-year capital forecast for equipment replacement need based on equipment condition, criticality, and risk; the first 30-years was used for this analysis. The USACE budget submissions used in support of the BP-26 IPR were used as a source for expense (operations and maintenance) values.

5.1.3.2 Structural Measure Costs

Structural Measure costs (capital and operations and maintenance) were estimated by USACE at the Class 5 level for each Action Alternative with structural measures (see Appendix M). Class 5 estimates (commonly referred to as "Rough Order of Magnitude") inherently have considerable risk and uncertainty resulting in high contingencies. For purposes of this analysis, it is assumed that contingencies are 50 percent, capital costs are incurred in Year 1 (2025), and operations and maintenance of the structural measures are escalated at the rate of inflation (2.1 percent annual average) for the 30-year study period.

5.1.4 Net Present Value Calculation[17]

The NPV compares the present value of benefits to the present value of costs. It considers the direct funded capital and expense (operations, routine and non-routine maintenance) forecasts, as well as the capital, operations and maintenances cost associated with structural

[16] Bonneville's share of basin-wide costs (e.g., RME) were not included in analysis. With inclusion of those costs, the Net Present Value estimates would be incrementally lower, and the Levelized Costs of Generation estimates would be incrementally higher.

[17] NPV was calculated by BPA and does not use USACE methodologies.

measures. System-wide costs, such as Bonneville's fish and wildlife program, are not included in the NPV. The NPV is calculated as:

$$NPV = \sum_{t=1}^{n} \frac{B_t - C_t}{(1+i)^t}$$
$$B = Benefits\ (generation\ revenue)$$
$$C = Costs\ (direct\ funded\ capital, expense, structural\ measures)$$
$$i = Discount\ Rate$$
$$n = Study\ period\ (30\ years)$$

Benefits and costs are forecast over the 30-year study period for each of the 630 iterations. These cash flows are discounted using Bonneville's Risk Free 2024 discount rate of 3.96 percent. Bonneville's Official Agency Discount Rate was determined to be the best applicable rate in this power specific NPV evaluation. A positive NPV indicates that power generation at the dams is economically justified, while a negative NPV indicates that costs outweigh the benefits.

5.1.5 Levelized Cost of Generation Calculation

The LCOG evaluates the incremental cost of producing power at a facility. It considers the direct funded capital and expense (operations, routine and non-routine maintenance) forecasts, as well as the capital, operations and maintenances costs associated with structural measures. System-wide costs, such as Bonneville's fish and wildlife program, are not included in LCOG. The LCOG is calculated as:

$$Levelized\ Cost\ of\ Generation = \frac{\sum_{t=1}^{n} \frac{C_t + E_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{G}{(1+i)^t}}$$
$$C = Direct\ funded\ capital + Structural\ measure\ costs$$
$$E = Expense\ (operations\ and\ maintenance)$$
$$G = Average\ annual\ generation$$
$$i = Discount\ rate$$
$$n = Study\ period\ (30\ years)$$

The LCOG takes the stream of forecasted costs over the 30-year study period and "levelizes" them to produce an annualized cost of power production. This measure, in $/MWh, is then compared to the levelized cost of alternative resources to understand the relative competitiveness and affordability of each dam.

5.2 Power Generation Economic Results

5.2.1 Power Generation Economics Summaries

5.2.1.1 Net Present Value

Median NPVs from the 630 iterations are shown in Table 5.2-1. The combined WVS projects with hydropower facilities have a positive median NPV of $356 million over the 30-year study period under the NAA.

All of the Action Alternatives result in a negative median NPV for all WVS projects combined, ranging from approximately -$771 million to -$1.4 billion. For individual WVS projects, only Hills Creek and Cougar have a positive NPV under one or more Action Alternatives, the NAA or Interim Operations. Hills Creek has a positive median NPV in the NAA and Alternatives 1, 2A, 2B, 5. It's NPV ranges from -$209 million in Alternative 4 to $61 million under Alternative 1. Cougar has a positive NPV of $15 million in Alternative 1 only.

Table 5.2-2 provides the percentage of the 630 iterations that resulted in a positive NPV under each alternative. Approximately 98 percent of iterations for the No Action Alternative resulted in a positive NPV for the Willamette Valley system. Across the Action Alternatives, no iterations resulted in a positive NPV for the combined WVS projects. For Interim Operations, 8.6 percent of the iterations resulted in a positive NPV.

5.2.1.2 Levelized Cost of Generation

Median LCOG are shown in Table 5.2-3 for each Action Alternative, NAA, and Interim Operations. Under the NAA, median levelized costs for the combined WVS projects are estimated to be $30.03/MWh. Under the Action Alternatives, LCOG ranges from $65.74/MWh in Alternative 2a to $91.48/MWh in Alternative 3a.

Table 5.2-1. 30-year Net Present Value by Alternative in Millions of FY25 Dollars (Median of 630 iterations, 3.96 Percent Risk Free Bonneville Discount Rate)3/

Project	NAA	ALT 1	ALT 2A	ALT 2B	ALT 3A	ALT 3B	ALT 4	ALT 5	Interim Operations
Detroit/Big Cliff1	84	-491	-498	-499	-257	-127	-502	-498	-59
Green Peter/Foster1/	53	-649	-244	-243	-192	-267	-160	-244	-84
Lookout Point/Dexter1/	99	-333	-148	-150	-219	-161	-324	-159	-140
Cougar	44	15	-60	-130	-56	-131	-62	-131	-20
Hills Creek	74	61	59	54	-67	-85	-209	49	89
Combined WVS Projects2/	**356**	**-1401**	**-891**	**-970**	**-789**	**-771**	**-1256**	**-986**	**-213**

1/ Cougar and Hills Creek dams are operated as individual projects. Additionally, peaking dams and their respective re-regulating dams are functionally operated together as individual projects; therefore, the combined peaking/reregulating dams (Detroit/Big Cliff, Green Peter/Foster, and Lookout Point/Dexter) are treated as individual projects.

2/ Net Present Values for combined WVS projects are calculated from the sum of benefits and costs across each project for 630 iterations. The median result may not equal the sum of median results for individual plants.

3/ Several key factors may incrementally increase costs further, which would incrementally decrease Net Present Values and increase cost of generation. Structural cost estimates used in the analysis of Action Alternatives were at a conceptual design level with a 50 percent contingency. For other projects of similar size and complexity, the conceptual design cost estimates increased by 137 to 215 percent upon completion of the detailed design report. Post construction, the complexity of these systems has typically resulted in further costs to improve performance. Higher implementation costs than currently estimated would result in additional reductions of the Net Present Value and increases in the levelized costs of generation. NPV was calculated by BPA and does not use USACE methodologies.

Additionally, the full costs of RPA measures from the NMFS Biological Opinion are pending outcomes of an adaptive management process that would result in a long-term flow management plan and may increase as RPAs are implemented (e.g., RPA 4.9 which could result in future Hills Creek operational or structural measures). Finally, Bonneville's share of basin-wide costs (e.g., RME), or costs of some court order structural measures (e.g., upgrades for Dexter adult fish facility), were not included in this analysis.

Table 5.2-2. Percent of 630 Iterations with a Positive NPV by Alternative

Project	NAA	ALT 1	ALT 2A	ALT 2B	ALT 3A	ALT 3B	ALT 4	ALT 5	Interim Operations
Detroit/Big Cliff[1/]	94.3	0.0	0.0	0.0	0.0	0.6	0.0	0.0	9.7
Green Peter/Foster[1/]	87.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2
Lookout Point/Dexter[1/]	97.5	0.0	3.3	2.9	0.0	0.0	0.0	1.4	0.0
Cougar	99.8	76.8	1.1	0.0	0.0	0.0	0.8	0.0	7.1
Hills Creek	100.0	100.0	100.0	100.0	0.0	0.0	0.0	100.0	100.0
Combined WVS Projects[2/]	**97.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**8.6**

1/ Cougar and Hills Creek dams are operated as individual projects. Additionally, peaking dams and their respective re-regulating dams are functionally operated together as individual projects; therefore, the combined peaking/reregulating dams (Detroit/Big Cliff, Green Peter/Foster, and Lookout Point/Dexter) are treated as individual projects.

2/Net Present Values for combined WVS projects are calculated from the sum of benefits and costs across each project for 630 iterations. The Combined WVS project value is not an average of the individual plants.

Table 5.2-3. FY25 Cost of Generation ($/MWh) by Alternative (Median of 630 iterations)[3/,4/]

Project	NAA	ALT 1	ALT 2A	ALT 2B	ALT 3A	ALT 3B	ALT 4	ALT5	Interim Operations
Detroit/Big Cliff[1/]	$31.80	$82.07	$82.29	$82.35	$129.90	$61.22	$82.63	$82.34	$50.52
Green Peter/Foster[1]	$35.72	$125.83	$85.39	$85.34	$75.99	$117.59	$69.87	$85.94	$56.07
Lookout Point/Dexter[1]	$29.26	$72.10	$53.89	$54.21	$102.87	$66.94	$70.89	$54.77	$61.23
Cougar	$26.32	$36.63	$58.84	$350.48	$77.65	$356.07	$59.50	$372.37	$52.47
Hills Creek	$17.99	$23.39	$23.64	$24.23	$67.14	$94.20	$96.64	$24.56	$17.75
Combined WVS Projects[2/]	**$30.03**	**$78.66**	**$65.74**	**$70.70**	**$91.48**	**$83.84**	**$76.34**	**$71.22**	**$48.95**

1/ Cougar and Hills Creek dams are operated as individual projects. Additionally, peaking dams and their respective re-regulating dams are functionally operated together as individual projects; therefore, the combined peaking/reregulating dams (Detroit/Big Cliff, Green Peter/Foster, and Lookout Point/Dexter) are treated as individual projects.

2/ Cost of Generation for combined WVS projects are calculated from the sum of costs and generation across each project for 630 iterations. The median result from the 630 iterations is displayed. Combined WVS project Cost of Generation is not an average across the individual projects as each project contributes a different amount of generation per year.

3/Bonneville's share of basin-wide costs (e.g., RME) were not included in this analysis. With inclusion of those costs, the Net Present Value would be incrementally lower and the Levelized Costs of Generation would be incrementally higher. Additionally, structural cost estimates used in the analysis of Action Alternatives were at a conceptual design level with a 50 percent contingency. For other projects of similar size and complexity, the conceptual design cost estimates increased by 137 to 215 percent upon completion of the detailed design report. Post-construction, the complexity of these systems has typically resulted in further costs to improve performance. Higher implementation costs than currently estimated would result in additional reductions of the Net Present Value and increases in the levelized costs of generation. NPV was calculated by BPA and does not use USACE methodologies.

4/Alternative 5 effects are only inclusive of Interim Operations and do not account for structural measures that have been proposed under the court order (e.g., Dexter Hatchery improvements), nor do they account for operational changes that could occur as a result of structural measure implementation.

5.2.2 Power Generation Economics: Alternative Comparisons to NAA

5.2.2.1 No-Action Alternative

Over the 30-year study period, the median NPV for the combined WVS projects under the NAA is about $356 million and the median LCOG is estimated to be $30.03/MWh.[18]

As Table 5.2-1 and Table 5.2-3 indicate, all projects[19] have positive median NPVs with Detroit/Big Cliff at $84 million ($31.80/MWh LCOG), Green Peter/Foster at $53 million ($35.72/MWh LCOG), Lookout Point/Dexter at $99 million ($29.26/MWh LCOG), Cougar at $44 million ($26.32/MWh LCOG), and Hills Creek at $74 million ($17.99/MWh LCOG). As shown in Table 5.2-2, NPVs were positive in a majority of iterations, ranging from 87.5 percent for Green Peter/Foster to 100 percent for Hills Creek.

5.2.2.2 Alternative 1: Change from NAA

Over the 30-year study period, power operations are estimated to have a median NPV of -$1.4 billion under Alternative 1.[18] This is a $1.76 billion, or 494 percent, reduction in NPV compared to the NAA. Across the 630 iterations that varied energy prices and water conditions, no iterations result in a positive NPV for the combined WVS projects. The median LCOG for the combined WVS projects is estimated to rise from $30.03/MWh under the NAA to $78.66/MWh under Alternative 1, which is a $48.63, or 162 percent, increase.

As Table 5.2-1 through Table 5.2-3 indicate, all WVS projects except Hills Creek and Cougar have negative median NPVs ranging from -$333 million (Lookout Point/Dexter) to -$649 million (Green Peter/Foster); LCOGs ranging from $72.10/MWh (Lookout Point/Dexter) to $125.83/MWh (Green Peter/Foster); and no iterations with positive NPVs. Hills Creek and Cougar have the only positive NPVs at $61 million and $15 million, respectively. Cougar's NPV is positive in 76.8 percent of model iterations while Hills Creek is positive in 100 percent of iterations. LCOGs are $36.63/MWh for Cougar and $23.39/MWh for Hills Creek.

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[18] Bonneville's share of basin-wide costs were not included in this analysis. With inclusion of those costs, the Net Present Value would be incrementally lower and the Levelized Costs of Generation would be incrementally higher. Additionally, structural cost estimates used in the analysis were at a conceptual design level with a 50 percent contingency. For other projects of similar size and complexity, the conceptual design cost estimates increased by 137 to 215 percent upon completion of the detailed design report. Post-construction, the complexity of these systems has typically resulted in further costs to improve performance. Higher implementation costs than currently estimated would result in additional reductions of the Net Present Value and increases in the levelized costs of generation. Bonneville's share of basin-wide RME costs

[19] Cougar and Hills Creek dams are operated as individual projects. Additionally, peaking dams and their respective re-regulating dams are functionally operated together as individual projects; therefore, the combined peaking/reregulating dams (Detroit/Big Cliff, Green Peter/Foster, and Lookout Point/Dexter) are treated as individual projects.

5.2.2.3 Alternative 2A: Change from NAA

Over the 30-year study period, power operations are estimated to have a median NPV of -$891 million under Alternative 2A.[18] This is a $1.25 billion, or 350 percent, reduction in NPV compared to the NAA. Across the 630 iterations that varied energy prices and water conditions, no iterations resulted in a positive NPV. The median LCOG for the combined WVS projects is estimated to rise from $30.03/MWh under the NAA to $65.74/MWh under Alternative 2A, which is a $35.71, or 119 percent, increase.

As Table 5.2-1 and Table 5.2-3 indicate, Hills Creek is the only WVS project that has a positive median NPV at $59 million under Alternative 2A. Its LCOG is $23.64/MWh. Hills Creek is the only project that has a positive NPV in more than 50 percent of the 630 iterations from the economic analysis. Other projects have negative median NPVs ranging from -$60 million (Cougar) to -$498 million (Detroit/Big Cliff); LCOGs ranging from $53.89/MWh (Lookout Point/Dexter) to $85.39/MWh (Green Peter/Foster); and a proportion of 630 iterations resulting in a positive NPV ranging from 0 percent (Detroit/Big Cliff and Green Peter/Foster) to 3.3 percent (Lookout Point/Dexter).

5.2.2.4 Alternative 2B: Change from NAA

Over the 30-year study period, power operations are estimated to have a median NPV of -$970 million under Alternative 2B[18]. This is a $1.33 billion, or 373 percent, reduction in NPV compared to the NAA. Across the 630 iterations that varied energy prices and water conditions, no iterations resulted in a positive NPV. The median LCOG for the combined WVS projects is estimated to rise from $30.03/MWh under the No Action Alternative to $70.70/MWh under Alternative 2B, which is a $40.67, or 135 percent, increase.

As Table 5.2-1 and Table 5.2-3 indicate, Hills Creek is the only WVS project under Alternative 2B that has a positive median NPV at $54 million. Its LCOG is $24.23/MWh. Hills Creek is the only project that has a positive NPV in more than 50 percent of the 630 iterations from the economic analysis. Other projects have negative median NPVs ranging from -$130 million (Cougar) to -$499 million (Detroit/Big Cliff); LCOGs ranging from $54.21/MWh (Lookout Point/Dexter) to $350.48 MWh (Cougar); and proportion of 630 iterations resulting in a positive NPV ranging from 0 percent (Detroit/Big Cliff, Green Peter/Foster, and Cougar) to 2.9 percent (Lookout Point/Dexter).

5.2.2.5 Alternative 3A: Change from NAA

Over the 30-year study period, power operations are estimated to have a median NPV of -$789 million under Alternative 3A.[18] This is a $1.15 billion, or 322 percent, reduction in NPV compared to the NAA. Across the 630 iterations that varied energy prices and water conditions, no iterations resulted in a positive NPV. The median LCOG for the combined WVS projects is estimated to rise from $30.03/MWh under the NAA to $91.48/MWh under Alternative 3A, which is a $61.45, or 205 percent, increase.

As Table 5.2-1 and Table 5.2-3 indicate, all of the WVS projects under Alternative 3A have negative median NPVs ranging from -$56 million (Cougar) to -$257 million (Detroit/Big Cliff) and LCOGs ranging from $67.14/MWh (Hills Creek) to $129.90/MWh (Detroit/Big Cliff); and no model iterations resulting in positive NPVs.

5.2.2.6 Alternative 3B: Change from NAA

Over the 30-year study period, power operations are estimated to have a median NPV of -$771 million under Alternative 3B.[18] This is a $1.13 billion, or 317 percent, reduction in NPV compared to the NAA. Across the 630 iterations that varied energy prices and water conditions, no iterations resulted in a positive NPV. The median LCOG for the combined WVS projects is estimated to rise from $30.03/MWh under the No Action Alternative to $83.84/MWh under Alternative 3B, which is a $53.81, or 179 percent, increase.

As Table 5.2-1 and Table 5.2-3 indicate, all of the WVS projects have negative median NPVs ranging from -$85 million (Hills Creek) to -$267 million (Green Peter/Foster); LCOGs ranging from $61.22/MWh (Detroit/Big Cliff) to $356.07/MWh (Cougar); and proportion of 630 model iterations resulting in a positive NPV ranging from 0 percent (Green Peter/Foster, Lookout Point Dexter, Cougar, Hills Creek) to 0.6 percent (Detroit/Big Cliff).

5.2.2.7 Alternative 4: Change from NAA

Over the 30-year study period, power operations are estimated to have a median NPV of -$1.26 billion under Alternative 4.[18] This is a $1.61 billion, or 453 percent, reduction in NPV compared to the NAA. Across the 630 iterations that varied energy prices and water conditions, no iterations resulted in a positive NPV. The median LCOG for the combined WVS projects is estimated to rise from $30.03/MWh under the NAA to $76.34/MWh under Alternative 4, which is a $46.31, or 154 percent, increase.

As Table 5.2-1 and Table 5.2-3 indicate, all of the WVS projects under Alternative 4 have negative median NPVs ranging from -$62 million (Cougar) to -$502 million (Detroit/Big Cliff); LCOGs ranging from $59.50/MWh (Cougar) to $96.64/MWh (Hills Creek); and proportion of 630 model iterations resulting in a positive NPV ranging from 0 percent (Detroit/Big Cliff, Green Peter/Foster, Lookout Point/Dexter, Hills Creek) to 0.8 percent (Cougar).

5.2.2.8 Interim Operations: Change from NAA

Over the 30-year study period, power operations are estimated to have a median NPV of -$213 million under Interim Operations.[18] This is a $569 million, or 160 percent, reduction in NPV compared to the NAA. Across the 630 iterations that varied energy prices and water conditions, 8.6 percent resulted in a positive NPV. The median LCOG for the combined WVS projects is estimated to rise from $30.03/MWh under the NAA to $48.95/MWh under Interim Operations, which is an $18.92, or 63 percent, increase.

As Table 5.2-1 and Table 5.2-3 indicate, Hills Creek is the only WVS project that has a positive median NPV at $89 million and an LCOG of $17.75/MWh. Other projects have negative median NPVs ranging from -$20 million (Cougar) to -$140 million (Lookout Point/Dexter); LCOG ranging from $52.47/MWh (Cougar) to $61.23/MWh (Lookout Point/Dexter); and a proportion of 630 iterations resulting in a positive NPV ranging from 0 percent (Lookout Point/Dexter) to 9.7 percent (Detroit/Big Cliff).

5.2.2.9 Alternative 5: Change from NAA

Alternative 5 assumes the same costs as Alternative 2B but with the minor differences in generation between the alternatives shown in **Error! Reference source not found.**. Over the 30-year study period, power operations are estimated to have a median NPV of -$986 million under Alternative 5.[18] This is a $1.34 billion, or 377 percent, reduction in NPV compared to the NAA. Across the 630 iterations that varied energy prices and water conditions, no iterations resulted in a positive NPV. The median LCOG for the combined WVS projects is estimated to rise from $30.03/MWh under the No Action Alternative to $71.22/MWh under Alternative 5, which is a $41.19, or 137 percent, increase.

As Table 5.2-1 and Table 5.2-3 indicate, Hills Creek is the only WVS project under Alternative 5 that has a positive median NPV at $49 million. Its LCOG is $24.56/MWh. Hills Creek is also the only project that has a positive NPV in more than 50 percent of the 630 iterations from the economic analysis. Other projects have negative median NPVs ranging from -$131 million (Cougar) to -$498 million (Detroit/Big Cliff); LCOGs ranging from $54.77/MWh (Lookout Point/Dexter) to $372.37/MWh (Cougar); and proportion of 630 iterations resulting in a positive NPV ranging from 0 percent (Detroit/Big Cliff, Green Peter/Foster, Cougar) to 1.4 percent (Lookout Point/Dexter).

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ATTACHMENT 1. HYDSIM MODELING BACKGROUND

The Willamette Basin is primarily rain based, and the projects are operated for flood risk management fall through spring. Flood risk management in the Willamette basin is accomplished by drafting the reservoirs behind the dams to low levels in the late fall before the rains start in order to provide storage space to retain inflow during downstream flood events. The release of any retained water during the flood season is regulated by the flow levels at downstream control points on the mainstem Willamette River, such as Albany and Salem, and individual tributaries, e.g., Jefferson on the Santiam River, whenever possible. After the flood season has passed, the reservoirs are filled with the spring inflows to their maximum conservation season level. Summer is climatically very dry, and the outflows are set for flow objectives for fish and wildlife and irrigation. There are eight projects that generate hydropower and they have minimal capability to shape generation to load. This cycle of drafting and filling is guided by a “Rule Curve” at each storage project that specifies the timing of each of these phases of regulation. The Rule Curve is the pool elevation that the reservoir is managed to stay at or below, when possible, with pool levels above the curve when operating for flood risk management, and pool levels below the curve when inflows are low and the stored water is released to meet the various, mostly fish and wildlife flow objectives, needs of the system.

The objective of the Willamette EIS is to assess the impacts of proposed changes to the Willamette Valley reservoir operations. Simulating reservoir operations over a wide variety of hydrologic conditions provides a quantitative tool to assess impacts and compare different alternative operations. Several existing datasets that extend to 2009 are already available to provide the inflow, evaporation, and irrigation data. ResSim models are used to model the system on a daily basis, which is better suited to simulate intra-month reservoir elevations, dam outflows, and evaluate potential flooding events (flood risk management). The NAA and alternatives were first modeled in ResSim by USACE, with output provide to Bonneville as input into the HYDSIM model, which simulates the system in 14 periods, monthly with two split months, April and August. The HYDSIM outputs are end of period project elevations, period average turbine outflow, spillway outflows, and period average generation.

Bonneville staff develop inputs for HYDSIM from inflow data from RESSIM provided by USACE, the 2010 Modified Flow dataset (80 water years, 2008 levels of irrigation depletion), the run-off forecast at The Dalles (1929 – 2009), upper rule curves from the RESSIM models, plant data from Pacific Northwest Coordination Agreement submissions by the USACE, and other requirements and flow priorities. Input quality control is provided by modeling staff before the HYDSIM model is run. Outputs are reviewed by multiple modeling staff to ensure the model is implementing the conditions as desired, and no conflicting requirements cause the model to not satisfy a desired operating condition. Further, all the hydroregulation of the alternatives were run through both the HYDSIM and ResSim models, and the outputs, specifically end of month elevation at projects, was compared by a group of hydro modelers for quality control.

The modeling approach for the WVS EIS aligned different model approaches and types to provide similar representations of key operations for all impact assessments. The three primary steps of the modeling approach are: input, modeling (or study/task), and output. This section describes the steps applied to achieve outputs for each alternative. Results from the hydroregulation modeling were used in subsequent modeling steps to provide results for different impact assessments. The results from the Bonneville hydropower simulation model (HYDSIM) portion of the hydroregulation studies were detailed sets of 73-year by 14-period (April and August being split months, Water Years 1935/36 – 2007/08) project outflows, reservoir elevations, reservoir contents, spillway flows at 11 projects and power generation data at the 8 power generating projects in the WVS. Specifically, the WVS HYSDIM model includes the hydroindependent Portland General Electric projects on the Clackamas River: Timothy, Oak Grove, North Fork, Faraday, and River Mill as well as the USACE projects on the Santiam River: Detroit, Big Cliff, Green Peter, Foster; the McKenzie River project Cougar; and Upper Willamette River projects Hills Creek, Lookout Point, Dexter, and the Lost Creek on the Rogue River. These projects were not connected as a complete system in HYDSIM, rather each tributary's projects were connected as individual system.

Five non-generating projects and three control points were added to the HYDSIM plant file during WVS EIS development. New project numbers and control point numbers were created from downstream to upstream in ascending order and are Fern Ridge, Cottage Grove, Dorena, Fall Creek and Blue River. The new control points Albany, Salem, and TW Sullivan. The control points are connected to the upstream projects as like actual physical location. For each project, the storage-elevation, maximum discharge, and project limits are from the HYSSR model and are verified by the HEC5 model from the USACE, Portland District. These tables are also used for calculating average generation at each project. Period average generation is calculated in HYDSIM based on run of river vs. reservoir project type. For reservoir type projects, average generation is determined mathematically by taking the product of turbine flow and H/K at a project, limited by a maximum generation constraint that is project dependent. Generation at Detroit, Cougar, Green Peter, Foster, Hills Creek, and Lookout Point is modeled in this way. H/K ("H over K") tables are from the Columbia HYDSIM model used in the CRSO and cross-checked against the RESSIM models. These tables relate H/K to head where "head" refers to the forebay elevation minus the tailwater elevation. The forebay elevation is the elevation that corresponds to the *average* storage for the project during the period of interest, not the difference between initial and ending elevation. Storage-elevation tables are provided and validated for each project by USACE, Portland District. Tailwater is constant for the Willamette projects. The re-regulation projects Dexter and Big Cliff are modeled as run of river, and in this case the average generation can be found by interpolating on the generation-discharge table using turbine flow.

The WVS EIS consists of several alternative operations that incorporate structural, flow, fish spill, and temperature control measures as well as a No Action Alterative (NAA). The NAA is intended to reflect the current operations with minimum flow objectives from the 2008 BiOp and maximum flow constraints from both project water control manuals as well as the 2008 BiOp. Additionally, the NAA includes measures at Detroit for temperature spill and at Foster for temperature/fish weir spill, which are detailed below. In HYDSIM, BiOp fish minimum flows at projects are used as project minimum flows.

The Action Alternatives contain different combinations of operational and structural measures. Measures are only modeled in ResSim if reservoir elevations, total outflow, or outlet specific flow are affected. For each alternative, the regulated flows, maximum flows, minimum flows, and spill for each project is sent to BPA for power analysis. The new flows, spill, and operational changes such as deeper draft limits are incorporated into a HYDSIM study and ultimately produce the average generation values for projects in the WVS.

ATTACHMENT 2. AVERAGE AND CRITICAL WATER GENERATION EFFECTS ON U.S. PROJECTS

This exhibit provides 73-year average (Water Years 1935/36 through 2007/08) and critical water (1937) average generation HYDSIM data by Willamette Valley System project (Table 1 through Table 14). The tabular generation details supplement the graphs in Section 3.1 of this appendix. HYDSIM uses a 14-period time step with April and August split into two half-month periods because these months tend to have substantial natural flow differences between their first and second halves. Negative numbers indicate an alternative produced less hydropower than the NAA.

Table 1. 73 Year Average Generation (Water Years 1935/36 through 2007/08) Differences: Alternative 1 vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	34	1	0	12	1	-1	-7	-2	39
NOV	19	1	2	10	6	3	3	1	45
DEC	-1	0	0	0	0	-1	-2	0	-4
JAN	-1	0	0	0	-2	0	-2	0	-5
FEB	0	0	0	0	-3	0	2	1	-1
MAR	-3	-1	0	-2	-1	0	-2	0	-11
APR1	-5	-2	-4	-2	2	-7	-7	-2	-26
APR2	-3	-1	-5	-3	2	-7	-9	-2	-29
MAY	3	0	-3	0	2	-3	-6	-2	-9
JUN	27	0	0	-2	-2	2	-2	-1	22
JUL	15	-1	4	-2	-4	7	7	2	30
AUG1	14	0	0	-2	-4	4	7	2	21
AUG2	13	0	-1	-2	-6	1	9	2	17
SEP	10	0	1	-12	-11	2	1	0	-9

Table 2. Critical Water Year (1937) Average Generation Differences: Alternative 1 vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	30	1	-2	2	-2	-1	-16	-4	8
NOV	12	0	2	21	7	4	5	1	52
DEC	0	0	0	-1	-3	2	-8	1	-9
JAN	0	0	2	0	-3	2	-7	0	-6
FEB	0	0	0	0	-4	0	-6	0	-10
MAR	-5	-2	0	0	1	0	-1	0	-7
APR1	-5	-2	0	0	5	0	-1	0	-3
APR2	10	2	0	0	3	5	3	1	24
MAY	1	0	0	0	4	0	0	0	5
JUN	48	0	0	0	2	0	0	0	50
JUL	20	0	1	-1	-3	1	2	0	20
AUG1	17	0	3	-3	-4	2	2	0	17
AUG2	16	0	-1	-3	-6	-5	7	2	10
SEP	16	0	1	-15	-11	6	-7	-2	-12

Table 3. 73 Year Average Generation (Water Years 1935/36 through 2007/08) Differences: Alternative 2A vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	27	-1	2	-13	9	5	8	2	38
NOV	19	1	2	-47	2	3	6	2	-13
DEC	-1	0	-2	-43	-4	-2	-2	0	-53
JAN	-1	0	-1	-19	-5	-1	-3	0	-30
FEB	0	0	0	-4	-4	0	1	1	-7
MAR	-3	-1	0	-3	-1	0	-3	0	-12
APR1	-5	-2	-4	-3	2	-6	-7	-2	-26
APR2	-1	-1	-4	-15	3	-7	-9	-2	-36
MAY	3	0	-2	-17	3	-2	-5	-1	-21
JUN	29	1	2	-12	1	4	2	0	28
JUL	21	1	0	-4	1	0	1	0	20
AUG1	19	2	0	-4	1	0	-2	-1	14
AUG2	18	2	-2	1	-2	-2	-2	0	12
SEP	3	-2	1	11	1	3	-2	-1	15

Table 4. Critical Water Year (1937) Average Generation Differences: Alternative 2A vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	17	-2	2	-15	5	6	3	1	17
NOV	12	0	1	-13	-1	3	4	1	7
DEC	0	0	-5	-17	-5	6	3	2	-16
JAN	0	0	1	-8	-3	2	0	0	-8
FEB	0	0	0	-4	-4	-1	-1	0	-10
MAR	-5	-2	0	-29	-6	0	-1	0	-43
APR1	-5	-2	0	-2	5	-2	0	0	-6
APR2	11	2	0	-20	3	1	1	2	0
MAY	1	0	0	-32	5	0	0	0	-26
JUN	48	0	0	-23	2	0	0	0	27
JUL	25	1	0	-4	2	0	1	0	25
AUG1	23	2	-1	-7	1	-3	-6	-2	7
AUG2	22	2	1	-7	-1	-7	-4	-1	5
SEP	6	-2	1	15	4	3	-4	-1	22

Table 5. 73 Year Average Generation (Water Years 1935/36 through 2007/08) Differences: Alternative 2B vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	27	-1	-14	-13	9	0	3	1	13
NOV	19	1	-18	-47	2	0	1	1	-41
DEC	-1	0	-16	-43	-4	-1	-2	0	-67
JAN	-1	0	-8	-19	-5	-1	-2	0	-36
FEB	0	0	2	-4	-4	-1	1	0	-6
MAR	-4	-1	-10	-3	-1	0	-2	0	-22
APR1	-5	-2	-17	-3	3	-7	-7	-2	-39
APR2	-1	-1	-19	-15	3	-7	-9	-2	-50
MAY	3	0	-20	-17	3	-1	-4	-1	-39
JUN	29	1	-18	-12	1	4	2	0	8
JUL	21	1	-14	-4	1	2	2	1	9
AUG1	19	2	-15	-4	1	2	1	0	6
AUG2	18	2	-16	1	-2	0	1	0	3
SEP	3	-2	-10	11	1	3	1	0	6

Table 6. Critical Water Year (1937) Average Generation Differences: Alternative 2B vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	17	-2	-14	-15	5	4	-1	0	-6
NOV	12	0	-20	-13	-1	-3	-5	0	-30
DEC	0	0	-9	-17	-5	9	5	3	-14
JAN	0	0	-5	-8	-3	2	0	0	-14
FEB	0	0	-7	-4	-4	-1	-1	0	-17
MAR	-5	-2	-10	-29	-6	-1	-1	0	-54
APR1	-5	-2	-19	-2	5	-2	0	0	-25
APR2	11	2	-23	-20	3	-9	-7	0	-43
MAY	1	0	-24	-32	5	0	0	0	-50
JUN	48	0	-19	-23	2	0	0	0	8
JUL	25	1	-13	-4	2	0	1	0	12
AUG1	23	2	-8	-7	1	0	-2	-1	8
AUG2	22	2	-7	-7	-1	-5	-1	0	3
SEP	6	-2	0	15	4	3	-2	0	24

Table 7. 73 Year Average Generation (Water Years 1935/36 through 2007/08) Differences: Alternative 3A vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	-20	-6	-10	-13	8	-11	-31	0	-83
NOV	-53	-4	-13	-47	-1	-15	-49	-2	-182
DEC	-47	-2	-8	-43	-4	-8	-34	-2	-148
JAN	-17	-2	0	-19	-3	-2	-16	-2	-60
FEB	11	4	6	-4	-1	-2	0	3	17
MAR	-28	8	-4	-3	-1	2	-10	8	-28
APR1	-42	5	-10	-3	0	-6	-28	4	-80
APR2	-43	5	-12	-15	0	-14	-34	3	-111
MAY	-60	-13	-14	-17	0	-12	-50	-12	-177
JUN	-24	-11	-12	-12	1	-6	-45	-10	-119
JUL	-15	-2	-9	-4	4	-1	-25	-1	-53
AUG1	-13	-1	-12	-4	3	0	-26	-3	-55
AUG2	-13	-1	-13	1	3	-2	-23	-3	-52
SEP	-30	-5	-8	11	6	-4	-24	-4	-59

Table 8. Critical Water Year (1937) Average Generation Differences: Alternative 3A vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	-15	-7	-8	-15	6	-8	-35	-1	-83
NOV	-35	-10	-18	-13	-1	-19	-40	-8	-144
DEC	-21	-2	-4	-17	-3	-1	-10	0	-58
JAN	-13	1	2	-8	-2	2	-8	0	-26
FEB	-19	0	7	-4	0	0	-13	0	-29
MAR	-28	8	-2	-29	-4	0	-18	8	-65
APR1	-36	5	-11	-2	0	2	-28	7	-63
APR2	-40	5	-15	-20	0	-6	-15	2	-89
MAY	-101	-18	-16	-32	0	-14	-92	-16	-289
JUN	-34	-17	-10	-23	0	-14	-83	-16	-197
JUL	-6	-1	-8	-4	5	-5	-11	-1	-31
AUG1	-4	1	-6	-7	3	-12	-18	-3	-46
AUG2	-7	0	-6	-7	4	-19	-20	-3	-58
SEP	-25	-4	-2	15	8	7	-25	-4	-30

Table 9. 73 Year Average Generation (Water Years 1935/36 through 2007/08) Differences: Alternative 3B vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	-3	3	-14	-19	-4	-11	-30	2	-77
NOV	-52	-1	-18	-47	-2	-15	-50	-2	-187
DEC	-47	-2	-16	-41	-3	-7	-39	-3	-159
JAN	-17	-2	-8	-17	-3	-1	-18	-2	-68
FEB	-4	0	2	20	6	8	6	1	38
MAR	-7	-2	-10	-5	9	-6	7	1	-11
APR1	-9	-2	-17	-28	6	-14	4	1	-59
APR2	-22	-1	-19	-25	4	-15	-22	0	-100
MAY	-32	-13	-20	-29	0	-17	-31	-12	-154
JUN	-1	-11	-18	-22	-3	-13	-27	-10	-106
JUL	3	2	-14	-13	0	-10	-14	1	-44
AUG1	6	2	-15	-15	-1	-13	-17	0	-54
AUG2	18	2	-16	-15	-3	-15	-13	0	-43
SEP	17	2	-10	-28	-9	-10	-3	1	-39

Table 10. Critical Water Year (1937) Average Generation Differences: Alternative 3B vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	-2	5	-14	-19	-7	-8	-30	1	-74
NOV	-35	-5	-20	-13	-2	-19	-40	-8	-142
DEC	-21	-2	-9	-17	-4	0	-10	0	-63
JAN	-13	0	-5	-8	0	2	-8	0	-32
FEB	-19	0	-7	-2	0	4	-13	0	-37
MAR	-18	-2	-10	-22	5	1	-6	0	-52
APR1	-12	-3	-19	-62	3	-1	10	2	-82
APR2	-35	-5	-23	-38	8	-9	-25	3	-124
MAY	-60	-18	-24	-56	-1	-23	-53	-16	-251
JUN	0	-17	-19	-42	-7	-23	-56	-16	-180
JUL	6	3	-13	-1	2	-7	-14	1	-23
AUG1	5	2	-8	-4	0	-11	-22	-1	-39
AUG2	21	2	-7	-6	0	-17	-25	-1	-33
SEP	26	3	0	-25	-6	-1	-2	2	-3

Table 11. 73 Year Average Generation (Water Years 1935/36 through 2007/08) Differences: Alternative 4 vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	27	-1	2	-14	-3	5	8	2	26
NOV	19	1	2	-13	1	3	6	2	20
DEC	-1	0	-1	-1	0	-2	-3	0	-8
JAN	-1	0	-1	0	-2	-1	-3	0	-7
FEB	0	0	0	0	-3	0	2	1	0
MAR	-3	-1	0	-2	-1	0	-2	0	-11
APR1	-5	-2	-4	-3	3	-6	-7	-2	-25
APR2	-1	-1	-4	-16	3	-6	-9	-2	-37
MAY	3	0	-2	-17	2	-2	-5	-1	-22
JUN	29	1	2	-12	1	5	2	0	27
JUL	21	1	0	-4	1	0	1	0	19
AUG1	19	2	0	-3	1	0	-2	-1	14
AUG2	18	2	-2	1	-2	-2	-2	0	13
SEP	3	-2	1	-9	-7	3	-2	-1	-14

Table 12. Critical Water Year (1937) Average Generation Differences: Alternative 4 vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	17	-2	1	-13	-3	7	2	1	10
NOV	12	0	1	-4	1	3	4	1	18
DEC	0	0	-5	-13	-6	5	-4	2	-21
JAN	0	0	1	-6	-3	2	-5	0	-11
FEB	0	0	0	0	-4	0	-4	0	-8
MAR	-5	-2	0	1	1	0	-1	0	-6
APR1	-5	-2	0	-7	5	-2	-1	0	-12
APR2	11	2	0	-27	3	5	4	2	0
MAY	1	0	0	-36	4	0	0	0	-31
JUN	48	0	0	-29	2	0	0	0	21
JUL	25	1	0	-5	1	0	1	0	23
AUG1	23	2	-2	-7	1	-2	-6	-1	8
AUG2	22	2	1	-7	-1	-9	-5	-1	2
SEP	6	-2	1	-12	-7	3	-6	-1	-18

Table 13. 73 Year Average Generation (Water Years 1935/36 through 2007/08) Differences: Interim Operations vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	26	-1	0	-7	0	7	-32	3	-5
NOV	-19	1	-9	-46	-3	7	-49	1	-119
DEC	-29	0	-8	-43	-4	1	-39	-2	-124
JAN	-28	0	-7	-18	-3	-3	-15	-2	-76
FEB	-16	0	-2	3	-5	0	-1	0	-20
MAR	-7	-1	-3	-16	-5	5	-12	-4	-43
APR1	-14	-2	-9	-18	-3	-7	-34	-9	-95
APR2	-22	-1	-10	-14	-3	-10	-40	-10	-110
MAY	-32	0	-11	3	-3	-7	-33	-6	-88
JUN	-1	1	-7	2	-3	1	-2	0	-9
JUL	1	1	2	8	0	1	-9	1	5
AUG1	3	2	-2	5	-1	0	-23	-1	-16
AUG2	7	2	-4	5	-3	0	-23	-1	-17
SEP	-3	-2	7	8	-5	0	-25	0	-19

Table 14. Critical Water Year (1937) Average Generation Differences: Interim Operations vs NAA.

	DET	BCL	COU	GRP	FOS	HCR	LOP	DEX	Combined WVS Projects
OCT	17	-2	4	-11	-2	15	-35	3	-11
NOV	-15	0	-15	-13	-2	6	-40	-3	-82
DEC	-13	0	-9	-17	-4	7	-10	1	-45
JAN	-8	0	-3	-8	-2	2	-8	0	-27
FEB	-12	0	-3	-3	-4	-5	-13	0	-40
MAR	-12	-2	-2	-17	-8	7	-6	-3	-43
APR1	-5	-2	-10	-44	-8	9	-16	-6	-82
APR2	-24	2	-13	-20	-4	-9	-61	-11	-140
MAY	-57	0	-4	0	-5	-11	-60	-8	-145
JUN	0	0	0	0	-5	-1	-8	0	-14
JUL	2	1	8	12	0	1	-5	1	20
AUG1	3	2	11	9	-1	-5	-25	-2	-8
AUG2	2	2	7	8	-3	-9	-27	-2	-22
SEP	1	-2	14	17	-4	7	-30	1	4