Impacts of Alternative Operations and Renewable Energy Deployment on Columbia River Hydropower

November 2024

Thushara De Silva,[1] Mike Swirsky,[2] Sanjeev Joshi,[2] David Graves,[2] and Anthony Teixeira[1]

1 National Renewable Energy Laboratory

2 Columbia River Inter-Tribal Fish Commission

Produced for the U.S. Department of Energy by the National Renewable Energy Laboratory (NREL).

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List of Abbreviations

BPA	Bonneville Power Administration
CRB	Colorado River Basin
CRITFC	Columbia River Inter-Tribal Fish Commission
CROM	Columbia River Operations Model
HRE	High renewable energy
LMP	Local marginal price
NREL	National Renewable Energy Laboratory
OASIS	Operational Analysis and Simulation of Integrated Systems
VRE	Variable renewable energy

Executive Summary

The Columbia River Treaty Tribes in the Pacific Northwest—the Nez Perce, Umatilla, Warm Springs, and Yakama—hold treaty-reserved fishing rights for the Columbia River, one of the world's most productive salmon rivers and a critical resource for these tribes. However, the tribes have expressed that current operating regimes of hydropower dams throughout the Columbia River Basin (CRB) do not fully account for tribal fishing rights and have negatively impacted fish populations. Four tribes acting together through the Columbia River Inter-Tribal Fish Commission (CRITFC)'s 2022 Energy Vision stated that current power system models often do not fully account for the many constraints faced by hydropower facilities in the CRB. As the deployment of variable renewable energy (VRE) like solar and wind continues to increase, power system flexibility will become increasingly important. As a result, there is a growing need to better understand the true capabilities of the hydropower generation fleet while accurately accounting for ecological constraints (Northwest Power and Conservation Council 2022). Understanding hydropower's role in a future grid with a higher share of VRE can inform water resources planning to address ecological needs.

The goal of this study is to examine the impacts of alternative hydropower operation rules and weather variability on hydropower generation and grid operations in VRE and transmission infrastructure deployment scenarios. The study evaluates how hydropower scheduling practices can reduce ecological impacts to the region's salmon populations. More specifically, the study examines the impact of today's dam water release rules (called "adjusted base water rules" in this study) and new, ecologically informed water release rules (called "ecosystem water rules" in this study) on two VRE scenarios (current renewable energy levels and higher renewable energy levels) using six weather years for each scenario (2008-2013). CRITFC developed the ecosystem water rules, which capture a portion of the changes they recommend for CRB hydropower operations. These analyses use a water resource planning model (OASIS) and a production cost model (PLEXOS) to simulate CRB reservoir cascade and Western Interconnection power grid operation.

The study indicated that some changes could be made to CRB hydropower operations to improve conditions for fish with limited impacts on electricity system costs and reliability. Key results from the modeling included the following:

- Water rule scenarios do not substantially change daily hydropower plant generation. As a result, total power grid operations cost, local marginal prices (LMPs), and grid reliability metrics do not change substantially across these scenarios.
- Power grid operation costs in the ecosystem water rules scenarios are about 1% higher on average for the Pacific Northwest region (for both the base grid and high renewable energy scenarios), and about 2% higher on average for the Bonneville Power Administration (BPA) (about 1% for the base grid scenarios and about 3% for the high renewable energy scenarios), relative to the adjusted base water rules scenarios.
- Operations costs vary more between years (due to factors such as weather variability and electricity system load) than between water rules scenarios. For example, in the base grid scenario, in 2010 (the highest average cost year) Pacific Northwest region operations costs are 18% higher than in 2011 (the lowest average cost year) for both the adjusted base water rules and the ecosystem water rules scenarios. In the HRE grid scenario, Pacific Northwest region costs are 31% and 32% higher in 2010 than in 2011 for the adjusted base water rules and ecosystem water rules scenarios, respectively.
- Results indicate that hydropower dispatch patterns vary across power grid scenarios, weather years, and water rule scenarios. However, relative to the adjusted base water rules, the ecosystem water rules did not substantially reduce the ability of hydropower plants to follow net load curves in higher renewable energy scenarios.

This study did not consider the impact of: 1) a broader range of changes CRITFC recommends to minimize the impacts of CRB hydropower operations on fish in the region, 2) changes in optimal transmission infrastructure buildout for the water rule scenarios, or 3) specific power contracts that constrain generation dispatches and transmission use. Further study is needed to explore these topics.

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Introduction

The Columbia River Treaty Tribes in the Pacific Northwest—the Nez Perce, Umatilla, Warm Springs, and Yakama—hold treaty-reserved fishing rights for the Columbia River, the largest river in North America flowing into the Pacific Ocean. The Columbia River was once one of the most productive salmon rivers in the world and a critical resource for Tribes in the region. However, the tribes have expressed that current operating regimes of hydropower dams throughout the Columbia River Basin (CRB) (**Figure 1**) do not fully account for tribal fishing rights and have negatively impacted fish populations. The four tribes envision a future where the Columbia River Basin (CRB) electric power system supports healthy and harvestable fish and wildlife populations, protects tribal treaty and cultural resources, and provides clean, reliable, and affordable electricity.

As an alternative to business-as-usual, the four tribes, acting through the Columbia River Inter-Tribal Fish Commission (CRITFC), have prepared a vision for a more harmonized energy and water system in their 2022 Energy Vision for the Columbia River Basin (Aja DeCoteau 2023). The Vision outlines four major issues: "(1) Many Columbia Basin salmon and steelhead populations are near extinction; (2) The climate crisis is already underway; without strong action, it will further reduce the survival of salmon and steelhead and damage every part of the region's economy and environment; (3) Renewable energy resources (hydropower, wind, and solar) will play a larger role in meeting future electricity needs in the region. Under the right conditions they can reduce greenhouse gases and benefit salmon. (4) Without proper integration and siting, renewable resources can make things worse for Columbia River salmon and other tribal resources." To help realize the Energy Vision, CRITFC has received technical assistance from the National Renewable Energy Laboratory (NREL) through the Communities Local Energy Action Program (LEAP) pilot to ensure tribes are fully informed and prepared to have their interests integrated into regional power system planning.

As stated in CRTFC's 2022 Energy Vision, current power system models often do not fully account for the many constraints faced by hydropower facilities in the CRB. Therefore, the models may inaccurately represent the ability of these facilities to respond to an increasing need for system flexibility. As the deployment of variable renewable energy (VRE) like solar and wind continues to increase, power system flexibility will become increasingly important. As a result, there is a growing need to better understand the true capabilities of the hydropower generation fleet (Northwest Power and Conservation Council 2022). In addition, as conventional thermal power plants that provide grid ancillary services and peak load are retired, hydropower's role is expected to shift from providing baseload generation to ancillary services and peak load. This may lead to increased hydropeaking operations—fluctuations in water releases as hydropower plants quickly ramp up and down—to balance VRE generation (Somani et al. 2021; De Silva et al. 2022). Changes in downstream flows associated with these operational modes can lead to different environmental impacts and require different mitigations (Jager et al. 2022). As a result, there is a need to study alternative hydropower system operation rules that consider downstream ecological water requirements. These efforts need to incorporate tribal treaty rights and account for potential threats to fish populations. Ultimately, any new VRE integration strategies must respect the cultural, ecological, and economic importance of fish populations.

CRITFC is interested in power grid modeling to understand (1) how hydropower operations would change in a future power grid with a high share of VRE and (2) how changes in hydropower operating rules—with the goal of supporting fish populations and upholding treaty rights—would impact grid operations costs and reliability. However, power grid modeling tools generally have limited capabilities to account for the specific goals and constraints of interest to CRITFC. Water resources models have capabilities to simulate ecological constraints and other water use constraints related to hydropower, but limited details of power grid operation. Several studies integrate water resources and power grid models to address similar limitations in power system modeling tools and explored information to better understand hydropower related constraints (Pracheil et al. 2022; De Silva et al. 2023). Integrated modeling approaches have been used for selected hydropower plants in the CRB to show the limitations of power system models in capturing hydropower-related constraints (Magee et al. 2022). However, the grid impacts of implementing water rules developed by the Columbia River Treaty Tribes and the role of Columbia River basin hydropower plants in a power grid with higher VRE levels have not been studied.

The goal of this study is to examine the impacts of alternative hydropower operation rules and weather variability on hydropower generation and grid operations in various VRE and transmission infrastructure deployment scenarios using an integrated modeling approach. The hydropower operation rules in this study incorporate a portion of the changes that CRITFC recommends for CRB hydropower operations. Future studies are needed to consider the impacts of a broader range of proposed changes to minimize the impacts of CRB hydropower operations on fish in the region.

Importantly, the study was a collaborative effort between NREL and CRITFC, with NREL providing power grid modeling expertise to CRITFC's water system modeling team. While other organizations are conducting similar analyses in the region, it's important for tribal organizations to conduct their own independent modeling that represents their interests. Ultimately, CRITFC would like to have the technical capacity to fully engage with states, utilities, other tribes, and the federal and Canadian governments on energy planning and policy issues. For example, while CRITFC participates in the development of the annual Fish Passage Plan for the CRB, they do not have a substantial role in the development of the Northwest Power Plan and the modeling tools used to create it (e.g., GENESYS). Through this study, CRITFC seeks to demonstrate how tribal rights and goals can be more effectively integrated into power system modeling using an integrated water-energy modeling approach.

Columbia River Basin Hydropower

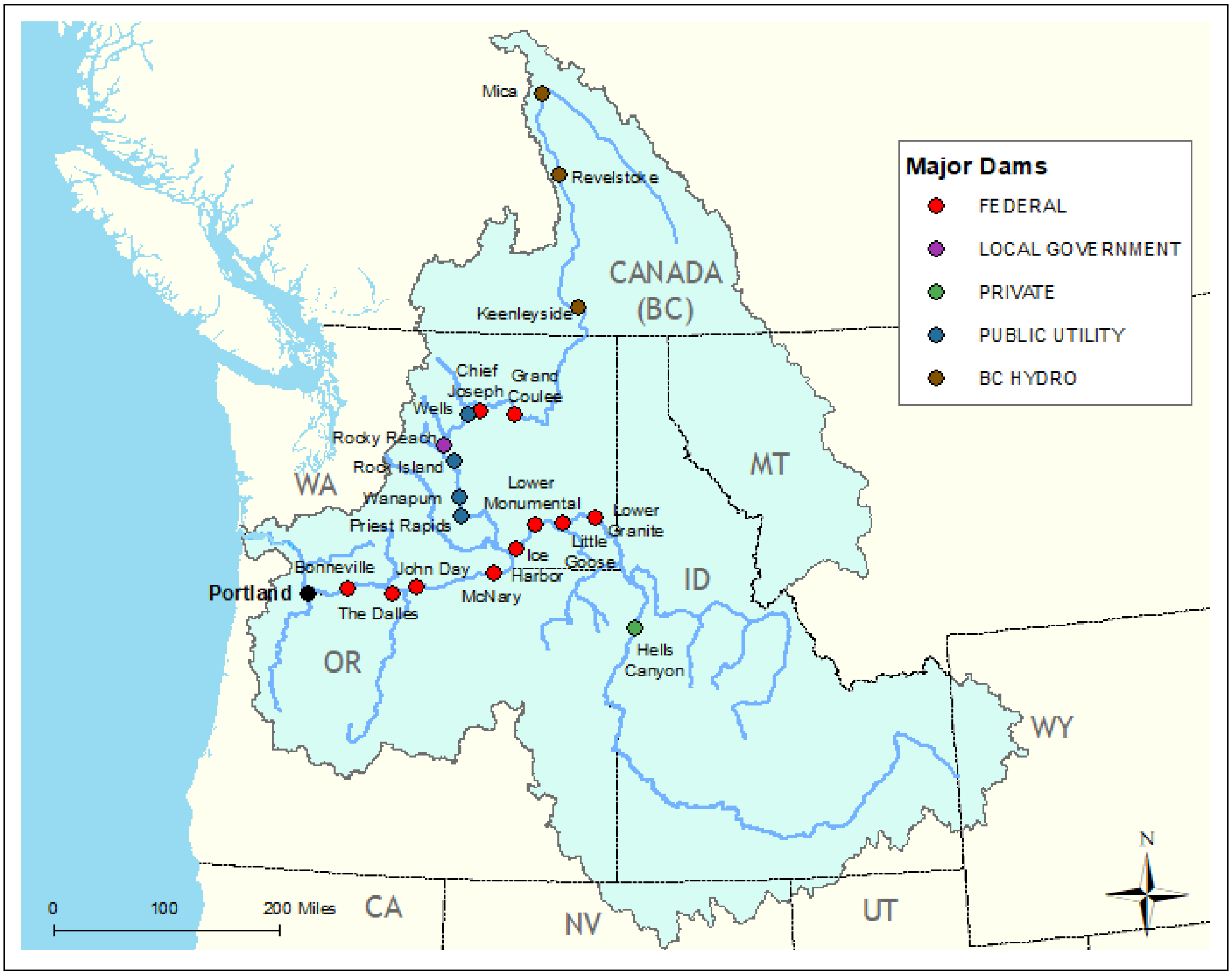

Figure 1. Major Dams in the Columbia River Basin

The Columbia River is a 1,200-mile river that starts in the Rocky Mountains of British Columbia, Canada and flows through the U.S. Pacific Northwest region to the Pacific Ocean. The CRB gathers an average annual runoff of about 244 billion cubic meters from its sub-basins in seven U.S. states (Washington, Oregon, Idaho. Montana, Wyoming, Nevada, and Utah) and one Canadian province (British Columbia) (Bonneville Power Administration, U.S. Army Corps of Engineers, and U.S. Bureau of Reclamation 2001). Historically, it produced abundant salmon runs and was central to the culture of the Indigenous Tribes of the region. However, construction of numerous dams and impoundments throughout the basin between the early 1900s and late 1970s have jeopardized the historical salmon runs and contributed substantially to major declines in salmon populations and habitat degradation (Graves et al. 2012). Currently, the river's main stem passes through 14 major hydroelectric dams. These dams, along with tributary projects, produced 44% of the total hydroelectric generation in the United States in 2012 (U.S. Energy Information Administration, 2014). Three of the 14 dams (Mica, Revelstoke, and Keenleyside, also called Arrow) are located in British Columbia, Canada and are owned and operated by BC Hydro. The remaining 11 dams are in the United States and owned and operated by the U.S. Army Corps of Engineers (5 dams), public utility districts (5 dams), and U.S. Bureau of Reclamation (1 dam). The Grand Coulee dam generates the most hydroelectric power in the CRB, with a net summer capacity of 6.8 GW. The 11 U.S. dams also provide flood control during periods of high runoff, navigation for barges and other vessels, water supply for municipal and industrial uses, and irrigation to surrounding agricultural communities.

CRB dams are divided into two categories: storage reservoirs and run-of-river dams. Storage reservoirs are dams with large storage units (known as reservoirs or artificial lakes) used for adjusting river flow patterns, storing water from rain and snowmelt, and providing flood control. Run-of-river dams have limited to negligible storage capability and are primarily used for navigation and hydropower generation. Water resource modeling for this project (explained in the section below) accounts for 6 storage reservoirs and 14 run-of-river dams in the CRB. Specifically, the Columbia River main stem includes 3 storage reservoirs (Mica, Arrow or Keenleyside, and Grand Coulee) and 11 run-of-river dams (Revelstoke, Chief Joseph, Wells, Rocky Reach, Rock Island, Wanapum, Priest Rapids, McNary, John Day, The Dalles, and Bonneville Dams); the Kootenai River includes 2 storage reservoirs (Libby and Corra Linn) and 3 run-of-river projects (Lower Bonnington, Kootenay Canal, and Brilliant Dams); and the Duncan River includes 1 storage reservoir (Duncan Dam).

Background on Power Grid Modeling

This section provides background on power grid modeling as context for the specific modeling methods selected for this study. Power grid modeling simulates the technical, economical, and other characteristics of the grid at various timescales, with an aim to analyze its behavior, ensure stability and reliability, optimize performance, and plan for future expansion.

Several power grid modeling tools are used to understand grid infrastructure expansion and operation in different spatial and temporal resolutions. Identifying future infrastructure needs of a specific power grid involves several steps with multiple models (De Silva 2024a; Brinkman et al. 2021; Gagnon 2023). This process is also known as integrated resource planning, which identifies potential plans to meet future energy demand considering supply and demand-side resources and transmission. These plans are prepared at regular intervals (two to four years), accounting for changes in policy, technology, and market conditions. Figure 2 illustrates the modeling framework, data, and study assumptions used in such processes to better understand the various possible grid infrastructure buildout scenarios and investment decisions (Cochran et al. 2021; Gagnon 2023; De Silva 2024b).

Capacity expansion models, which are used for long-term power system planning, consider many constraints, drivers of change, and power sector investments. Given their scope providing a system-wide long-term outlook, capacity expansion models represent power grid operations and shorter time-scale behaviors in a simplified way. Detailed operational analyses require the use of production cost models, resource adequacy models, and power flow analysis models.

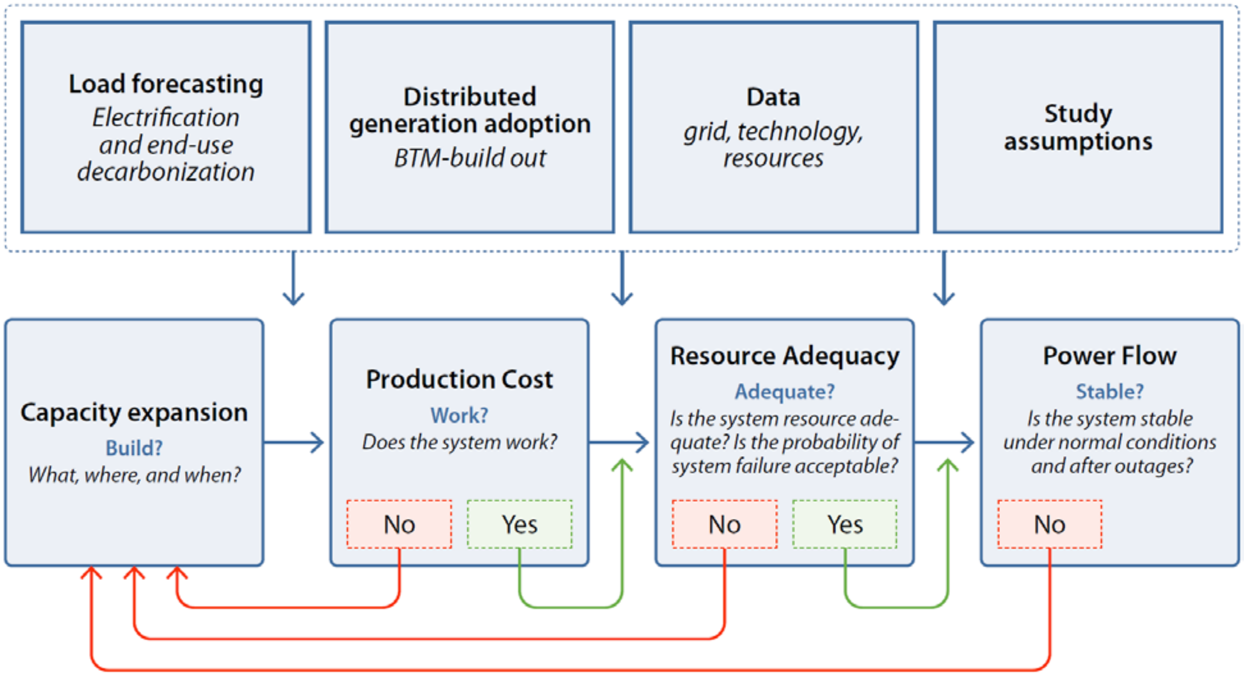

Figure 2. Bulk Power System Modeling Approach for Capacity Expansion

Figure 2 shows the elements of bulk system modeling, including:

- <u>Load forecasting:</u> Electric load projections in sufficient temporal and spatial resolution for multiple consumer categories and load profiles.
- <u>Distributed generation adoption:</u> Different pathway projections for behind-the-meter (BTM) distributed PV deployment (such as rooftop-PV) for the residential, commercial, and industrial sectors.
- <u>Data:</u> Data on wind and solar resources, electric load, hydropower water use, power grid topology, technologies, fuel prices, policies, regulations, and constraints.
- <u>Study assumptions for scenarios:</u> Policy sensitivities, constraints, scenario development, technology selection, cost sensitivities, reliability, economic and supply chain forecasts, and other planning parameter sensitivities.
- <u>Capacity expansion model:</u> Capacity expansion tools, such as Regional Energy Development System (ReEDS) (Ho et al. 2021), Resource Planning Model (RPM) (Hale, n.d.), and Aurora (Energy Exemplar, n.d.), focus on medium- and long-term scenarios for investment planning decisions for grid infrastructure expansion. These tools optimize infrastructure buildout—such as installing new generators, storage, and transmission infrastructure—and operations cost under given constraints. They consider a range of possible future grid expansion scenarios, capturing various policy goals, technology development, and uncertainty of assumptions. The scenarios project different levels of renewable energy deployment, thermal power portfolios, storage technologies, and transmission infrastructure expansion. These tools frequently model hydropower based on long-term and medium-term energy availability and a limited representation of operating constraints and flexibility.
- <u>Production cost model:</u> Production cost models (PCMs) such as PLEXOS (Energy Exemplar 2024), PROMOD (Hitachi Energy 2024), and MAPS (GE VERNOVA 2024) simulate short-term power grid operations and can account for variations in and uncertainty of load and VRE (wind and solar).

They examine hourly or sub-hourly generation scheduling and economic dispatch, consider transmission topology, and ensure provision of various types of operating reserves. PCMs balance the load and generation of a given system and identify times of potential strain characterized by curtailment, unserved energy, and unserved reserves. PCMs frequently model hydropower plants linked to reservoirs with constraints on energy availability for a given period such as a month, week, or day. They can incorporate fixed or flexible hourly profiles depending on the plant's flexibility.

- Resource adequacy model: Resource adequacy refers to the power grid's ability to serve electricity demand with an acceptably low risk of failure due to power supply shortfalls or deliverability issues. Resource adequacy models conduct system reliability and resource adequacy testing for different weather conditions that affect wind and solar output, load profiles, risk of thermal power outages, and other contingency events.
- Power flow analysis: Power flow modeling can be used to measure transmission system reliability, examining real and reactive power flow, fault tolerance, and contingency response over very short periods of system stress (milliseconds to minutes).

This study seeks to characterize changes in grid operations under various renewable energy deployment and hydropower operational scenarios. It does not seek to determine the optimal buildout of new assets and retirement of existing assets. Therefore, the study team used NREL's previously developed future power grid infrastructure scenarios based on the modeling framework in Figure 2. NREL then conducted production cost modeling to characterize the operational details of the existing and future grid scenarios.

The cost outputs of the scenario comparison are grid operational costs and do not include grid infrastructure buildout costs. Therefore, caution should be exercised when comparing production cost differences between scenarios with significantly different generation or transmission assets. This is especially true when considering portfolios with significantly different amounts of renewable energy and thermal power plants. Total costs for renewable energy include a much smaller proportion of variable costs (e.g., no fuel costs). As a result, operations costs can be expected to be significantly lower for a high-renewables grid, assuming all other relevant factors are held equal.

Methods

Water-Energy Integrated Modeling Approach

For this study, CRITFC and NREL collaborated to integrate a water resources model, the Operational Analysis and Simulation of Integrated Systems (OASIS) tool, and a production cost model, PLEXOS, to better understand the impacts of different Columbia River hydropower operations scenarios (Figure 3).

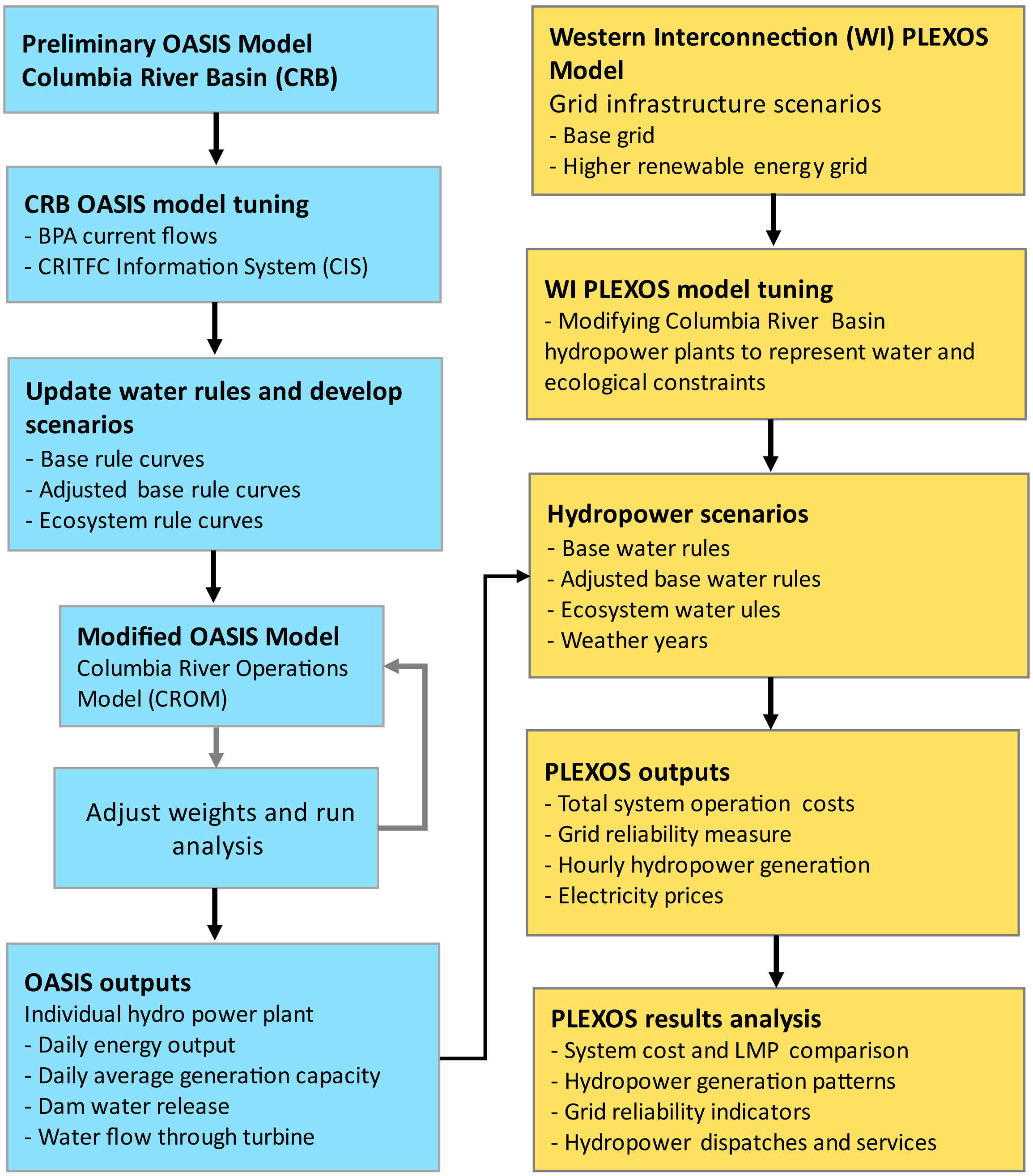

Figure 3 Integrated Modeling Approach Combining Water and Grid Models

Water Resource Modeling

Introduction to OASIS and CROM

OASIS, which models the operations of water resources systems, is owned, maintained, and enhanced by the water project engineering firm, Hazen and Sawyer. OASIS uses linear programming to optimize system operations for each time step in a simulation period (Hazen and Sawyer 2009). Linear programming is a method used to maximize or minimize a cost function used to create an optimized mathematical representation of an overall system. OASIS does not perform a single optimization for an entire period of record. Instead, it optimizes system operations for each time-step (one day) depending on user-defined goals and constraints. Time-step optimization is a useful framework for simulating water resource systems because it is similar to how dam operators operate their systems. Because of its flexible input and output forms, database storage structure, transparent code, and ability to integrate with other models, OASIS has been used to model diverse water management systems throughout North America for over two decades (Rivera 2024; Meyer et al. 1999).

The Columbia River Operations Model (CROM) is a version of OASIS that utilizes its linear optimization technique and Operations Control Language scripting language to simulate reservoir operations on the Columbia River and its tributaries (Hazen and Sawyer 2023). CROM was originally developed as part of the 2013 master's dissertation of Mark F. Cecchini Beaver, *Transboundary Columbia River Operational Alternative Analysis in a Collaborative Framework* (Beaver 2013). Cecchini Beaver recognized that the CROM model does not perfectly replicate the long-term, observed Columbia River system flows and reservoir levels. It uses current operating rules, Endangered Species Act–required storage levels, spill requirements, and flows modified by irrigation depletions and river regulation. Because of this, CROM was calibrated by Cecchini Beaver to replicate the results of the River Management Joint Operating Committee's 2011 climate impacts study using Hydro-system Simulator (HYDSIM) (U.S. Army Corps of Engineers and Bonneville Power Association 2011). HYDSIM is a monthly time-step, deterministic model created and used by the Bonneville Power Administration (BPA) and other hydro-system operators. In the model, April and August are divided into half months because of the large changes in the CRB within these months. It is widely regarded as an accurate representation of the Columbia River system.

CRITFC acquired a license for CROM in November 2022, enabling CRITFC to install, execute, and modify the model. CRITFC modified and updated the original CROM to include the most current hydrologic input data (through 2018) and system rules and constraints (2023) used by the federal agencies operating the Columbia River hydro-system. CROM was selected for CRITFC's evaluation of climate change impacts on hydro-operations because it was already built for the purpose of investigating Columbia River water management strategies using a current suite of performance measures related to flood control, hydropower, instream flow, recreation, navigation, and shoreline (stable or variable level) goals. In addition, a version of CROM is currently in use by the Indigenous Nations in Canada for their evaluations of hydro-operation influences on Indigenous priorities.

CROM Methodology

Like all OASIS models, CROM is built using "nodes," "arcs," and "inflows.". A node is a point of interest in the system, which may be of two different types: (1) junction nodes and (2) reservoir nodes. Junction nodes represent locations where water leaves the model domain and are used for run-of-river dams, important gage points, and confluences, while reservoir nodes are used for the six reservoirs in the model domain with significant active storage capacity—Mica, Arrow, Duncan, Libby, Kootenay Lake, and Grand Coulee. Arcs are the features that convey unidirectional water flow between nodes. Inflows are locations where a predetermined amount of water enters or exits the system at a node. CROM has two kinds of inflows: headwater and local. Headwater inflows occur at five nodes: Mica (100), Libby (200), Duncan (220), the Pend Oreille River Inflow (480), and the

Snake River Inflow (690), while local inflows occur at the other nodes in the system. **Figure 4** shows the CROM schematic, where yellow circles represent junction nodes, blue triangles represent reservoir nodes, black lines connecting the nodes represent arcs, and the purple lines and arrows represent the inflow at the node to which they connect. The node numbers serve as a reference for various functions in the model code.

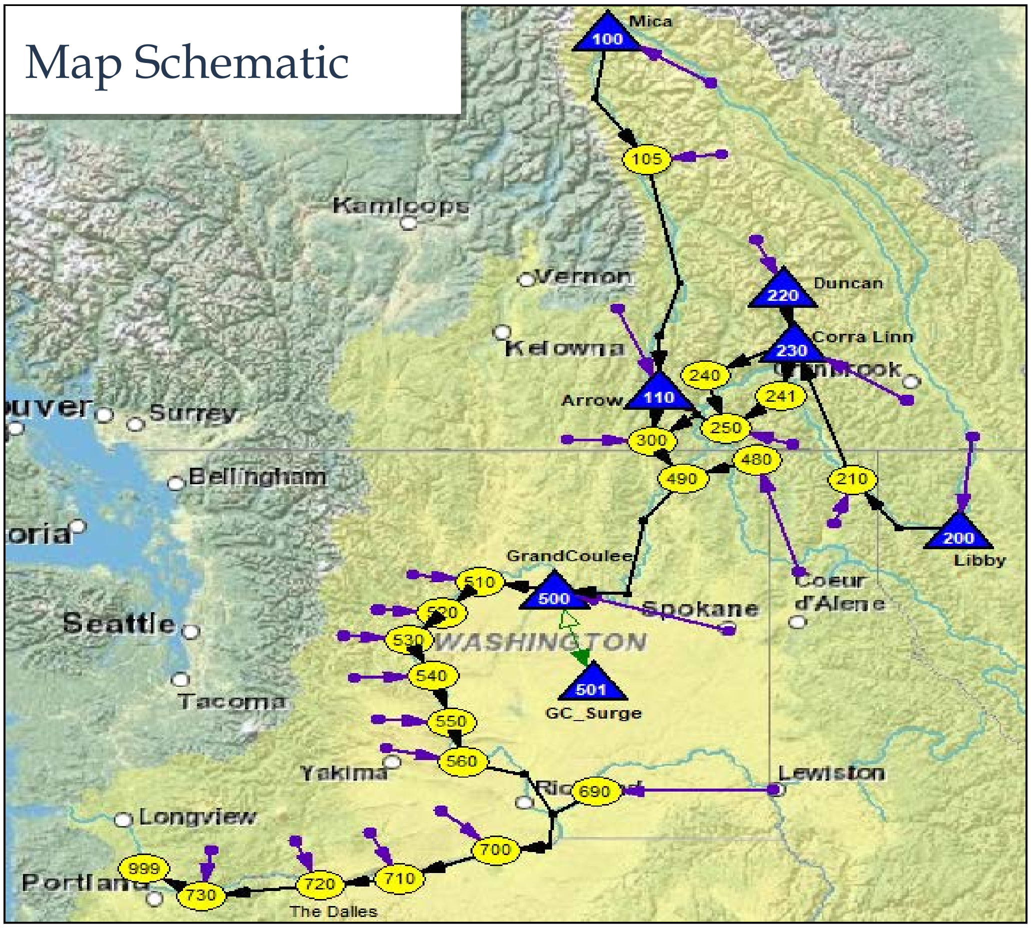

Figure 4. Schematic of the Columbia River Operations Model (CROM) Showing Nodes, Arcs, and Inflows

Data Inputs

CROM uses three external drivers that serve as time-series data inputs in the model: inflows, loads, and energy prices.

Inflow data consists of modified flows data obtained from the BPA. Modified flows are defined as the historical stream flows that would have been observed if today's irrigation withdrawals existed in the past, and if the effects of river regulation were removed—except at the upper Snake, Deschutes, and Yakima basins, where current upstream reservoir regulation practices are included. Irrigation practices have changed significantly over time, so the observed historical stream flows have been adjusted to account for current levels of irrigation depletions. The initial CROM version obtained from Hazen and Sawyer in 2022 used the modified flow data during the 1928-2008 period extracted from the 2010 Level Modified Streamflow Report. Later, CRITFC study team extended the modified flow data from 2008 to 2018 based on the 2020 Level Modified Streamflow Report (Bonneville Power Administration 2021). They also extended the CROM simulation time through 2018.

In CROM, energy load data approximates the share of firm load served by the hydropower projects. However, CROM has separate load datasets for Canada and the United States, using 2011 data to represent loads served by hydropower for all years in the model. Hourly hydropower generation for 2011, sourced from the BPA and BC Hydro websites, were averaged to provide a single capacity value for each day. An approximation of the firm power served by the projects in CROM was developed from the 2011 hourly generation pattern throughout the year, adjusted by the average critical period capacity (Beaver 2013). The study team lacked the necessary information to incorporate more recent firm generation estimates in CROM. As an alternative, a sensitivity analysis was performed to examine the effects of employing different firm generation requirements, which likely have changed since 2011. For this analysis, the firm energy assumptions in the model were multiplied by various factors to examine their effects on model results. The analysis revealed that factoring the firm generation with multipliers from 0.5 to 1.1 would cause a negligible difference on the CROM outputs while multipliers of 1.2 and above caused substantial differences. Multipliers below 0.5 were not evaluated. The implications of firm generation variability on OASIS model optimization could be explored further in future studies.

The energy price data from the Cecchini Beaver version of CROM were used in its updated version (CROM v2). While Cecchini Beaver was not able to obtain pricing data for the Canadian portion of the CRB, the Cecchini Beaver version of CROM used 2011 peak price data for the Mid-Columbia wholesale power trading hub from U.S. Energy Information Administration (U.S. Energy Information Administration 2024). This data reflects 2011 weather, streamflow, and economic conditions as well as court-imposed spill requirements from that year. Nevertheless, because the data cover the same period as the load data, they were considered a useful approximation for the value of power during the simulation period.

In addition, CROM uses volume forecasts for the modified flows. Volume forecasts are used to anticipate runoff patterns in the winter and spring, support flood risk reduction, and inform the flood rule curves used at each hydropower project. Issued monthly between January and June, they are primarily based on the seasonal mountain snowpack, which supply spring and summer river flows. CROM contains daily volume forecast data for each historical year and applies them in the same way that the U.S. Army Corps of Engineers and BPA use them for the rule curves that govern reservoir elevations and releases. The daily volume forecast values in CROM were linearly interpolated from 14-period volume forecasts based on the 1928-2018 modified flows.

CROM Goals and Constraints

Goals (also known as targets) are rules that CROM tries to meet, while constraints are rules that CROM can never violate. There are three general types of goals in CROM: rule curves, generation targets, and flow targets. Constraints in the CRB include water supply, dam and reservoir dimensions, power plant characteristics, and electrical grid (Beaver 2013). When goals compete with one another, CROM will attempt to meet the goal with the higher user-specified weight. The study team updated the flow targets where necessary to match those in the 2023 Water Management Plan (Bonneville Power Administration et al. 2023).

Rule Curves

Rule curves guide the reservoir levels to maximize operational objectives. Run-of-river projects do not currently have rule curves because they are assumed to have no storage capacity. The various types of rule curves are defined below in this section.

CROM allows the user to adjust upper and lower rule curves with a fixed multiplier. Unlike operational models used by the U.S. Army Corps of Engineers to manage the hydropower system continuously, the current version of CROM does not calculate rule curves on an ongoing basis. The upper rule curves are not modified because of prevalent operational goals of flood control in storage dams throughout the Columbia River main stem. The variable energy content curve, the assured refill curve, and the critical rule curve generally define the operational floor for the storage reservoirs. A rule curve based on these limits is determined for each reservoir according to an algorithm contained in the OCL model code (Beaver 2013). Table 1 lists the data sources for all rule curves.

UPPER RULE CURVE

The upper rule curve defines the reservoir elevations necessary for flood control. A single time series taken from Columbia River hydropower plant data files (Beaver 2013) defines this curve for each reservoir at each time step.

LOWER RULE CURVE

The lower rule curve defines the minimum storage necessary to meet firm generation under various conditions. Using an algorithm defined by Columbia River Treaty operating plans, CROM selects a lower rule curve that allows the reservoir to release water for firm power generation (and other purposes) while providing a high likelihood of refill. The lower rule curves in CROM were obtained from several sources.

VARIABLE ENERGY CONTENT CURVE

These curves, obtained from BPA, allow for secondary generation while maintaining a 95% refill probability (Bonneville Power Administration 2011). The curve changes each year depending on the runoff forecast.

ASSURED REFILL CURVE

These curves define the reservoir levels necessary for a high probability of refill by July and are the same for every year in the record. They were sourced from the 2011–2012 Columbia River Treaty Detailed Operating Plan, which incorporates results from past Pacific Northwest Coordination Agreement studies (Beaver 2013).

CRITICAL RULE CURVE

This rule curve defines the reservoir levels necessary to meet the hydro-system's share of the firm load under the worst historical water conditions (currently the 1936—37 water year). It is the same for every year in the record and was sourced from the 2011–2012 Columbia River Treaty Detailed Operating Plan, which incorporates results from past Pacific Northwest Coordination Agreement studies (Beaver 2013).

ECOSYSTEM RULE CURVES

These curves were originally developed for the CRITFC Information System, a predecessor to CROM developed by CRITFC that employed a user interface to operate the HYDSIM Model for different scenarios. The curves attempt to shape reservoir releases to a peaking hydrograph to mimic historical spring freshets (natural runoff peaks from snowmelt) more closely and to aid the downstream migration of juvenile salmon and steelhead smolts. To protect resident fish ecosystems and tribal cultural resources, the curves aim to provide fuller, more stable reservoir elevations without compromising upper rule curves that minimize flood risk. The rules were developed for operations at Grand Coulee, Mica, and Arrow, which contain most of the system storage available for management. Ecosystem rule curves from the CRITFC Information System are used in CROM to simulate alternative river operation scenarios during drier years, as determined by annual water supply forecasts.

Figure 5 illustrates ecosystem water rule simulation for the Grand Coulee dam. The upper rule curve, lower rule curve, ecosystem rule curve, and model storage values are measured on the left Y-axis ("Storage MAF"), and the water volume forecast and dry year cutoff values are measured on the right Y-axis ("Apr-Aug Forecast (MAF)"). Daily water releases (the green line labeled "Ecosystem Rule") depend on the upper and lower rule curves, model storage, the water volume forecast for April-

August, and the dry year cut off. When the water volume forecast is lower than the dry year cutoff, upper and lower rule curves remain high and water releases are lower (i.e., storage volumes remain high) during winter and early spring months. For example, year 2009 and 2010 upper and lower rule curves remain high during winter and early spring months. Conversely, when the water volume forecast is higher than the dry year cutoff, upper and lower rule curves remain lower and water releases are higher (i.e., storage volumes decrease). Although 2009 is a dry year, at the beginning of the year the water volume forecast is higher than the dry year cutoff. Therefore, water releases during the 2009 winter and early spring months are higher than in typical dry years.

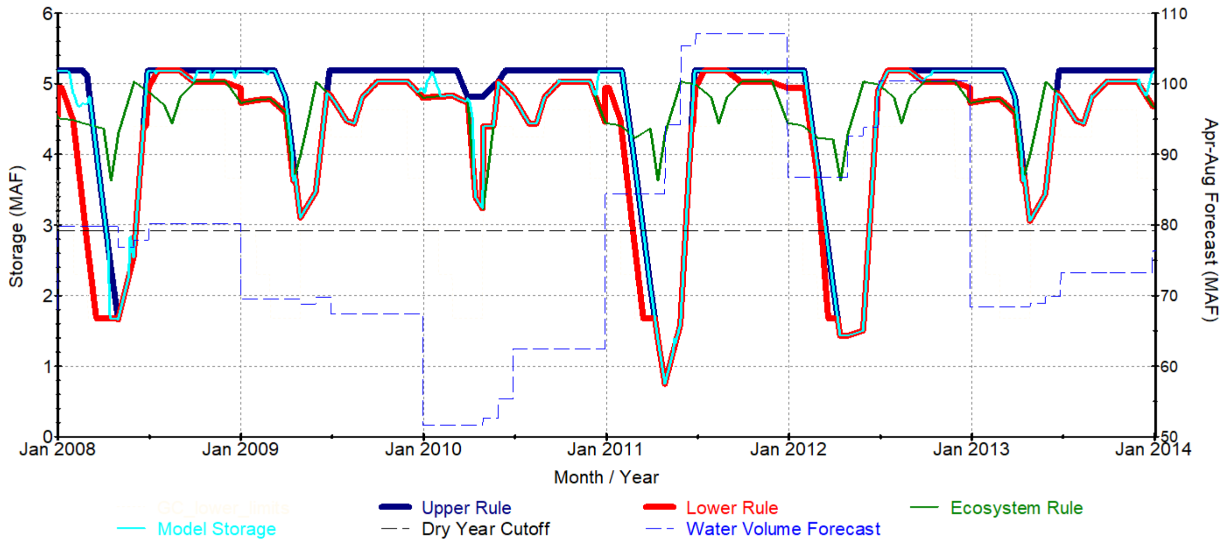

Figure 5 Grand Coulee Dam Ecosystem Water Rules Simulation

Table 1. Rule Curves Used in CROM and Their Data Sources

Data	Source
Variable energy content curve	Bonneville Power Administration
Critical rule curve	Columbia River Treaty Operating Committee, 2011, Detailed Operating Plan for Canadian Storage, Exhibit 9 (DOP11-12)
Assured refill curve	Columbia River Treaty Operating Committee, 2011, Detailed Operating Plan for Canadian Storage, Exhibit 9 (DOP11-12)
Grand Coulee Draft Limit	Bonneville Power Administration, U.S. Bureau of Reclamation, U.S. Army Corps of Engineers, 2012 Water Management Plan (pp. 51) & BPA 2012 Loads and Resources Study Documentation (p. 126)
Ecological Rule Curves	BPA and CRITFC Information System

CROM Outputs

CROM produces four primary types of outputs for each day and node in the simulation:

- Streamflow: the river discharge flowing through all dams (both run-of-river and storage)

- Reservoir water storage: the water level acquired by each storage dam
- Average daily energy generation: relates to the generation of hydroelectric power from all run-of-river or storage dams able to generate electricity
- Spill: the amount of water that bypasses each hydropower plant without being used for generation (required for fish passage).

Notably, CROM does not track electricity demand and therefore does not calculate the excess hydropower generation not needed to serve net load (i.e., total electric load minus wind and solar generation). CROM assumes net load is greater than total hydropower generation. Updating CROM to reflect current conditions at multiple projects was an iterative process that involved adjusting targets and weights in the model linear programming. Each adjustment required examining the results throughout the multiple projects (nodes) of the CRB to ensure that operations were not disrupted inadvertently by the enforcement of new goals.

Once this process was completed, the study team developed multiple scenarios with the updated model (CROM v3) to represent different practices for managing the hydropower system. These scenarios were developed for learning purposes and are not intended to be final policy recommendations from CRITFC or NREL. They are also not intended to coincide with scenarios that are currently being developed as part of the Columbia Basin Restoration Initiative of the "Six Sovereigns"—the states of Washington and Oregon and the four CRITFC member tribes (Nez Perce, Yakama, Umatilla, and Warm Springs). These scenarios are captured in more detail in Table 3.

In this study, CRITFC delivered 4 CROM outputs: daily discharge (flow), spill, reservoir elevations, and hydropower generation. While CROM was run for a 90-year record (1928-2018), the study team incorporated the 2008-2013 results into PLEXOS. This provided a manageable, continuous, recent time period with a good sampling of dry, normal, and wet years based on the total spring and summer flow forecast for the Columbia River (**Figure 6**).

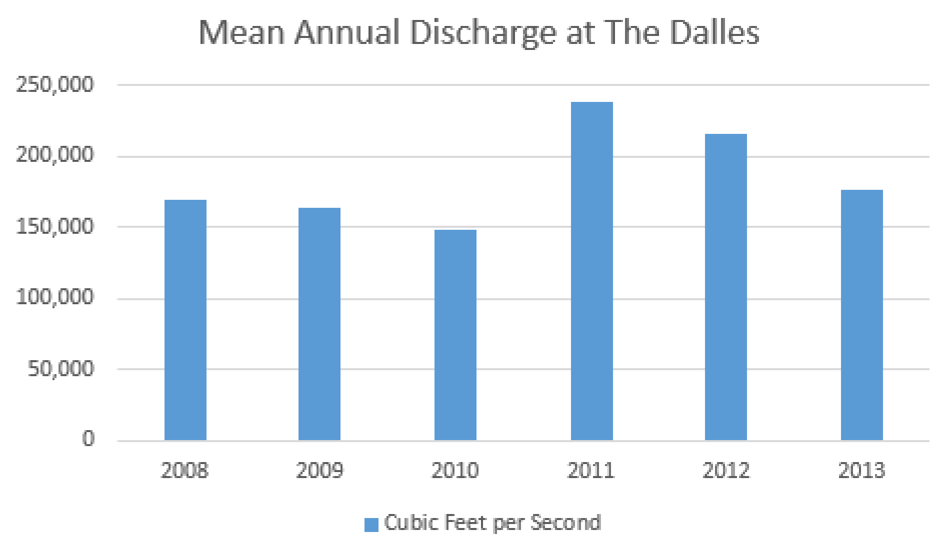

Figure 6. Mean Annual Discharge at The Dalles Dam (cfs) by Water Year (October 1–September 30)

Production Cost Modeling

NREL chose a commercially available PCM, PLEXOS, which is widely used to simulate power grid operations on an hourly basis (Energy Exemplar 2024). Using PLEXOS, NREL modeled several scenarios with varying weather, grid infrastructure changes across the Western Interconnection grid

(Figure 6), and rules for operating the CRB cascade hydropower plants. The Western Interconnection includes 14 U.S. states and the Canadian provinces of British Columbia and Alberta (Western Electricity Coordinating Council, n.d.). PLEXOS optimizes for least-cost unit commitment and economic dispatch of every generator in the system, given the physical and other constraints of the system. These constraints include the hourly electricity demand, the operating parameters of individual generators, the transmission system topology, and the availability of wind, solar, and water for electricity generation. It also ensures the sufficient provision of operating reserves.

The PLEXOS model simulates day-ahead generating unit commitment and economic dispatch of the system with hourly resolution, using forecasted wind and solar profiles. It includes medium-term and short-term modeling steps to efficiently handle long-run constraints in a shorter time frame. The medium-term step handles all user-defined constraints that span several weeks or months. It uses a simplified model and considers only the load duration curve to plan long-term, energy-limited resources like hydropower. Monthly or weekly energy targets are used to get daily energy targets. This information passes into the short-term modeling step, which executes full chronological unit commitment and economic dispatch using mixed-integer programming. Day-ahead forecasted flexibility, contingency, and regulating reserves are used. The study team used an additional one-day look-ahead with hourly time resolution in this step.

PLEXOS's outputs include hourly optimal dispatch of the generation fleet, locational marginal prices, and total generation cost (including fuel, variable operating and maintenance costs, and start and shutdown costs). PLEXOS can also identify transmission lines or paths that exhibit congestion and reliability concerns, such as unserved load or reserve failures.

Hydropower Modeling

In this study, hydropower plants were modeled using three methods in the PLEXOS model.

(1) Dispatchable hydropower plants with reservoirs were modeled with monthly energy maximum limits and other operational parameters (maximum capacity, minimum stable levels, and ramp rates).

(2) Non-dispatchable run-of-river hydropower plants were modeled as hourly fixed generation profiles.

(3) Pumped storage hydropower plants were modeled with upper and lower reservoir capacities with energy volumes.

Hydropower plant operation is constrained by ramping rates and maximum and minimum stable capacity values. In the medium-term optimization, monthly hydropower energy is allocated for each day of the short-term schedule, considering these constraints.

In PLEXOS, the CRB hydropower plants were modeled as dispatchable power plants with daily maximum energy limits based on the daily dam water releases values from OASIS model outputs. In addition, the hourly minimum flow requirement is prescribed for Bonneville, Chief Joseph, John Day, Libby, McNary, Dalles, and Priest Rapids power plants. Further, hourly minimum flow values are prescribed for Snake River hydropower plants: Little Goose, Ice Harbor, Lower Granite, and Lower Monument. The maximum ramping rates for hydropower plants were also simulated. Table A-1 shows the hourly minimum flow and ramping rates.

The study team simulated daily maximum energy limits in PLEXOS by separating them into fixed hourly generation and dispatchable, daily maximum constraints. OASIS outputs provided dam spill and turbine flows and calculated daily generation corresponding to the turbine flow. In the hourly time step, the minimum flow requirement is met by spill flow alone or both spill and turbine flows. If the spill cannot meet the hourly minimum flow requirement, the balance is met by turbine flow. In these periods, the total turbine flow is divided to meet hourly minimum flow requirements, and the balance is released according to the grid's hydropower needs. In other words, daily maximum generation is divided into hourly fixed generation (to meet hourly minimum flow) and dispatchable daily generation.

To evaluate the grid impacts of weather variability, the study team incorporated six years of weather data (2008-2013) into PLEXOS along with data on load, reserve products, hydropower, wind, and solar generation.

Geographic Scope

CRITFC wanted to understand the potential impacts of renewable energy deployment across western North America because a large amount of energy flows across this region. In addition, variable renewable energy creates a need for additional power plant flexibility, and the Pacific Northwest hydropower offers a potential source of that flexibility (Northwest Power and Conservation Council, n.d.). Therefore, while CRITFC's water modeling was limited to the CRB, NREL's modeling team chose to conduct power grid modeling across the Western Interconnection to understand the impacts of regional renewable energy deployment on hydropower operations.

This study used NREL's dataset for the Western Interconnection power grid (Figure 7). The dataset includes thousands of generators, busbars (nodes), and transmission infrastructure that connects generators with loads.

Transmission Modeling

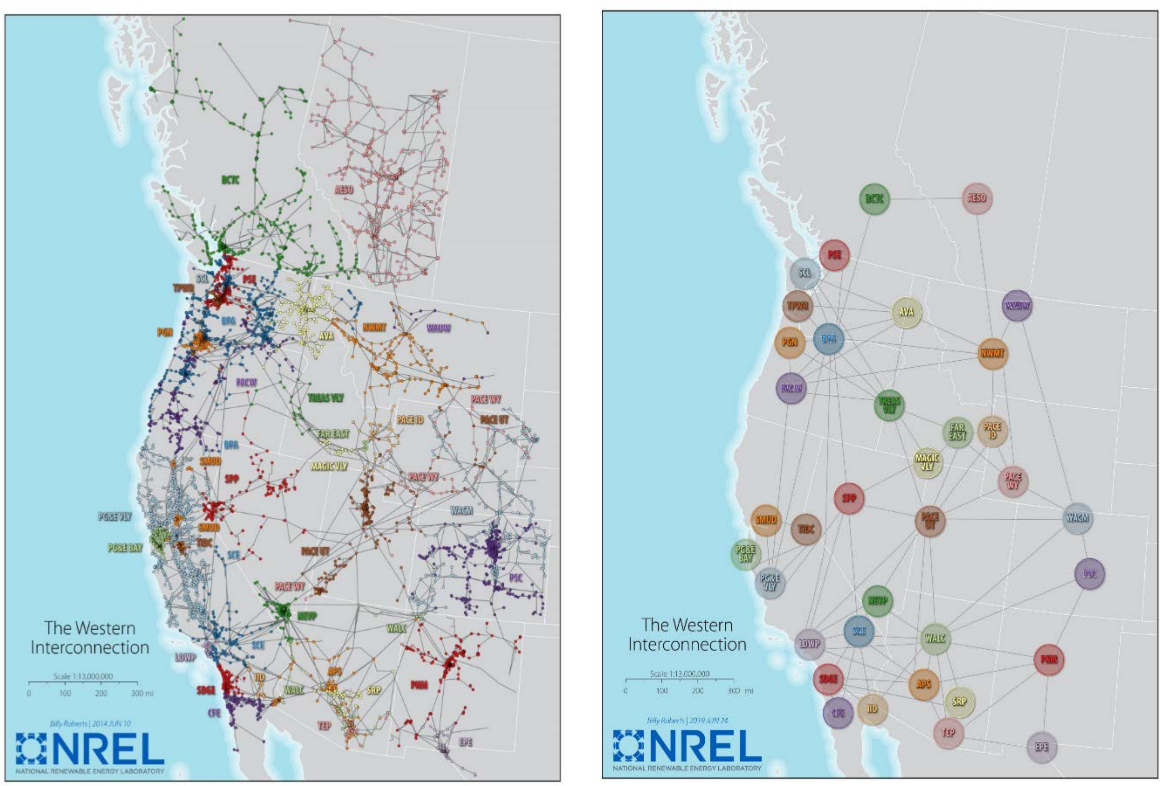

Figure 7. Detailed and Simplified Transmission Representations of the Western Interconnection Power Grid

PLEXOS simulates transmission in either a detailed or simplified way. The detailed transmission simulation includes details of transmission infrastructure within and between balancing authorities—known as nodal-level granularity (**Figure 7***,* left). The simplified transmission simulation only includes transmission lines between balancing authorities, called zonal-level granularity (**Figure 7**, right). To simplify calculations for this study, the team combined nodal- and zonal-level transmission simulation, including nodal-level transmission for the CRB focus regions and zonal-level transmission for the rest of the Western Interconnection.

CRB hydropower plants are operated by 14 balancing authorities in the U.S. power grid's Pacific Northwest region. The study team simulated nodal-level transmission for all of these balancing authorities, which account for the majority of CRB hydropower energy sales (**Table 2**).

Table 2. Focus Region of Detailed Power Grid Transmission Modeling

Balancing Authority	CRB Hydropower Plants
Bonneville Power Administration	Grand Coulee, Chief Joseph, Libby, McNary, John Day, Dalles, Bonneville
Chelan County PUD No.1	Rocky Reach, Rock Island
Grant County PUD No.1	Wanapum, Priest Rapids
Douglas County PUD No.1	Wells
Seatle City Light	
City of Tacoma, Department of Public Utilities	
Avista Corporation	
North Western Energy	
PacifiCorp West	
Portland General Electric Company	
Puget Sound Energy	
Upper Great Plains West	
Alberta Electric System Operator	
British Columbia Hydro Authority	Mica, Revelstoke, Arrow Lake, Corra Linn, Upper and Lower Bonnington, Kootenay Canal, Brilliant, South Slocan

Study Scenarios

The study examined grid impacts for three reservoir operating water rules and weather variability. It used two grid infrastructure scenarios to understand impacts with base grid infrastructure and grid with high renewable energy contribution share. Using the 2008–2013 dataset, it examined how load and hydropower, wind, and solar generation varied with weather. The details of the study scenarios are shown in **Table 3**.

Table 3. Study Scenario Details

Scenario	Description
Base water rules and base grid	Daily energy limits are provided from OASIS model results based on strict adherence to reservoir water resources planning rules and base power grid infrastructure.
Base water rules and high renewable energy grid	Daily energy limits are provided from OASIS model results based on strict adherence to reservoir water resources planning rules and high renewable energy power grid infrastructure.
Adjusted base water rules and base grid	Daily energy limits are provided from OASIS model results based on reservoir water resources planning rules that strive to replicate current operations and base power grid infrastructure.
Adjusted base water rules and high renewable energy grid	Daily energy limits are provided from OASIS model results based on reservoir water resources planning rules that strive to replicate current operations and high renewable energy power grid infrastructure.
Ecosystem water rules and base grid	Daily energy limits are provided from OASIS model results based on reservoir water resources planning rules that better support fish populations and base power grid infrastructure.
Ecosystem water rules and high renewable energy grid	Daily energy limits are provided from OASIS model results based on reservoir water resources planning rules that better support fish populations and high renewable energy power grid infrastructure.

Water Rule Scenarios

The study team examined 3 water rule scenarios and created three versions of CROM:

1. Base water rules (CROM 3.1): This base case for Columbia River operations strictly strives to meet all system requirements for flow levels at each project, including minimum flows, maximum flow rates of change, spill (water that bypasses turbines to support downstream juvenile fish migration and maintain reservoir levels as dictated by rule curves).

2. Adjusted base water rules (CROM 3.2): This adjusted base case allows for more flexibility to avoid disrupting the overall seasonal system integrity. It does this by assigning less stringent flow requirements, preserving target operating curves, and striving to meet the objectives in the strict base case. In discussions with water management professionals, it was determined that the adjusted base case is a more realistic simulation of current water operations in the CRB. Therefore, the study team chose this scenario as the base case going forward.

3. Ecosystem water rules (CROM 3.3): After the base case scenarios were complete, the ecosystem rule curves were translated from the CRITFC Information System for use in CROM, adjusted as necessary to match the model's logic. These rule curves were implemented in the adjusted base case to simulate an ecosystem water rule scenario. We examined the results and further adjusted the ecosystem rule curves as needed in order to meet the objective of providing more downriver flow to juvenile fish between mid-April and mid-July during the driest 40% of years modeled (as determined by the seasonal water volume forecasts).

Power Grid Scenarios

Many states in the Western Interconnection are planning for additional renewable energy deployment. CRITFC wanted to better understand the impacts of varying hydropower operations scenarios on costs and reliability at multiple levels of renewable energy deployment. Capacity expansion modeling was out of scope for this study. Instead, NREL used two previously developed scenarios for installed generation and transmission: (1) a modeled base scenario representing the current 2024 grid and (2) a higher-renewables scenario representing a potential future grid (Novacheck et al. 2021; Brinkman et al. 2021). **Figure 8** shows the capacity mix of the base grid scenario (2024) and the higher renewable grid scenario, compared with the historical year (2020). In the base grid scenario, a significant portion of the capacity is from thermal power, such as natural gas-fired combined cycle, combustion turbine, and coal power. In the high renewable energy grid scenario (HRE grid scenario), the thermal power share is lower, and wind and solar (utility-scale PV and behind-the-meter PV) share are higher. In addition, nuclear capacity drops gradually, and hydropower capacity remains relatively stable when transitioning from 2020 to the base and high renewable energy grid scenarios. In these two grid scenarios, approximately 26% and 51% of total generation comes from renewable energy resources across the Western Interconnection.

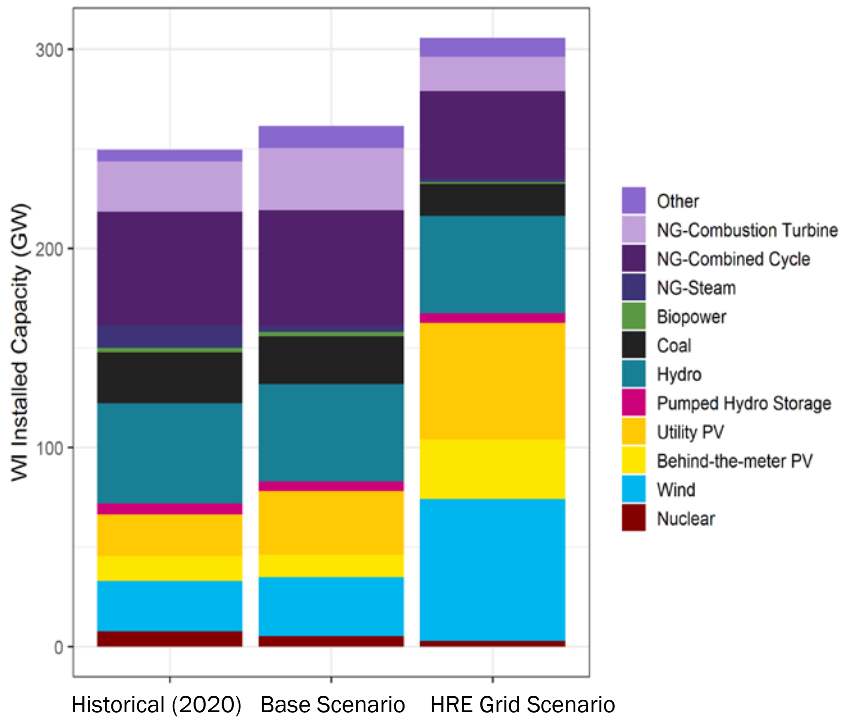

Figure 8. Renewable Power Share of Grid Scenarios

The production cost model results include technical and economic details such as generator dispatch levels, transmission use, operating costs, and reliability. From the hour-by-hour optimal dispatch of the generation fleet, the study team examined how hydropower dispatches vary across scenarios. The team also examined how operating costs and marginal prices differ among scenarios.

In this study, the PLEXOS model did not include specific contract details and power market design for energy sales from or between balancing authorities since this data is not typically publicly available. Contract structures can have a significant impact on generator dispatch and transmission use and in turn on operations costs and marginal prices. Importantly, market prices in practice can deviate from marginal costs due to market design, contract structures, cost recovery for non-variable costs, and bidding strategies. In addition, retail electricity prices are generally not set directly based on marginal costs and must balance considerations such as cost recovery and equity.

Results

Variations in Hydropower Generation Patterns

The total hydropower generation budgets of the scenarios differ due to weather variability and water resources planning rules. The OASIS model outputs include daily spill, turbine flow, and hydropower generation. Table 4 includes annual addition of spill and turbine flows from all CRB dams modelled in the OASIS model. 2012 had the highest spill, turbine flows, and generation, and 2010 had the lowest values. Relative to the adjusted base water rules scenario, the ecosystem water rules scenario had higher total dam spills for the 2008–2013 weather years to meet ecological water needs. Notably, in 2009 the ecosystem water rules scenario's turbine flows were higher than in the adjusted base water rules scenario. As a result, the ecosystem water rules scenario's total annual hydropower generation in 2009 was higher than in the adjusted base water rules scenario. This is a result of the volumetric forecast at the beginning of 2009 being higher than the dry year cut off and actual water volumes, leading to higher water releases than in a typical dry year. Figure 5 illustrates an example of this relationship for the Grand Coulee Dam.

Table 4. Spill, Turbine Flows, and Generation of CRB Hydropower Plants for Different Weather Years and Water Rule Scenarios

Weather Year	Spill AWR (kcfs)	Spill EWR (kcfs)	Turbine Flow AWR (kcfs)	Turbine Flow EWR (kcfs)	Generation AWR (GWh)	Generation EWR (GWh)
2008	93,204	94,226	491,691	481,513	102,328	99,598
2009	72,767	77,971	440,603	457,628	92,522	94,861
2010	71,469	74,257	436,637	417,890	91,867	88,536
2011	133,255	134,704	616,369	609,873	123,322	121,508
2012	137,898	142,981	630,619	616,572	129,116	126,274
2013	89,946	104,171	519,691	516,046	110,154	109,240

Note: AWR refers to adjusted base water rules and EWR refers to ecosystem water rules.

Hydropower generation patterns across water rules and weather years were compared across multiple time resolutions (monthly, daily and hourly) and discussed in the below. Only the adjusted base water rules and ecosystem water rules scenario results are included in the figures since the base water rules scenario doesn't reflect real-world operations. Comparison of results of the two water rules can be found in Appendix A.

Hydropower Monthly Generation Across Water Management Scenarios

Figure 9 shows the total monthly hydropower generation of CRB hydropower plants from the OASIS model results. Figure A-1 and Figure A-2 illustrate the monthly generation of Bonneville and Grand Coulee hydropower plants. There were significant differences in hydropower generation due to weather variability. Similar to spill and turbine flows, hydropower generation budgets for 2011 and 2012 were higher than for other years.

These results indicate that the monthly generation values of each water resources rule scenario are slightly different. With the ecosystem water rules scenario, generation during late spring and early summer is generally higher than or equal to the values with the adjusted base water rules scenario. For example, in dry weather years such as 2009 and 2010, June, July, and August generation values for the ecosystem water rules scenario are higher than for the adjusted base water rules scenario.

These differences are a result of the design and implementation of the ecosystem water rules. In years that are forecast to have less available runoff, these rules modify hydropower system operations to preserve more water in the upper reservoirs during the winter—and subsequently discharge this water between mid-April and mid-July to support the downstream migration of juvenile salmon and steelhead. Additionally, the ecosystem water rules spill more water over the dams for juvenile migration than is currently required.

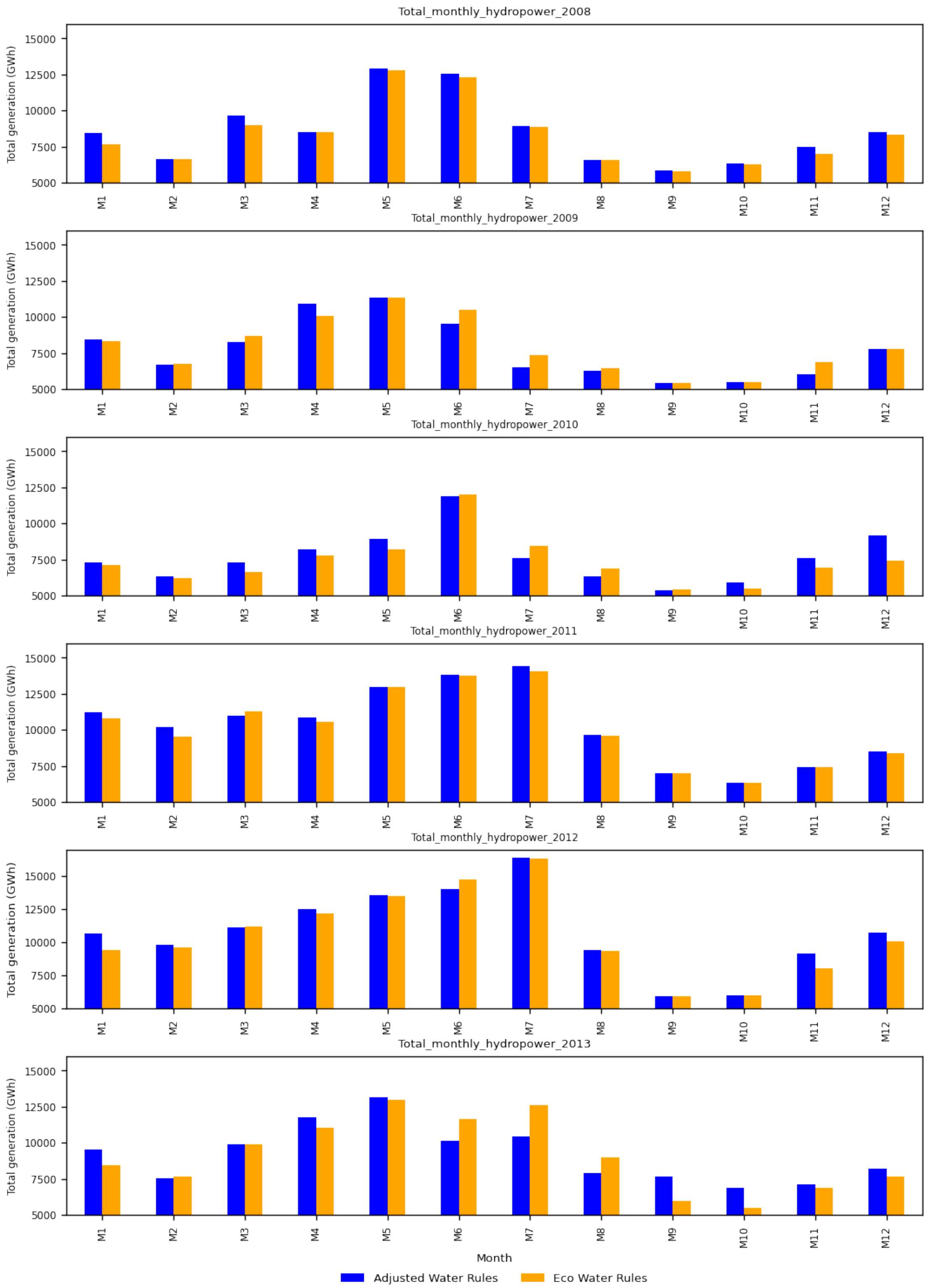

Figure 9. Monthly Hydropower Generation Variability for Various Weather Years and Water Rule Scenarios (M1 = January)

Generation Mix for Scenarios

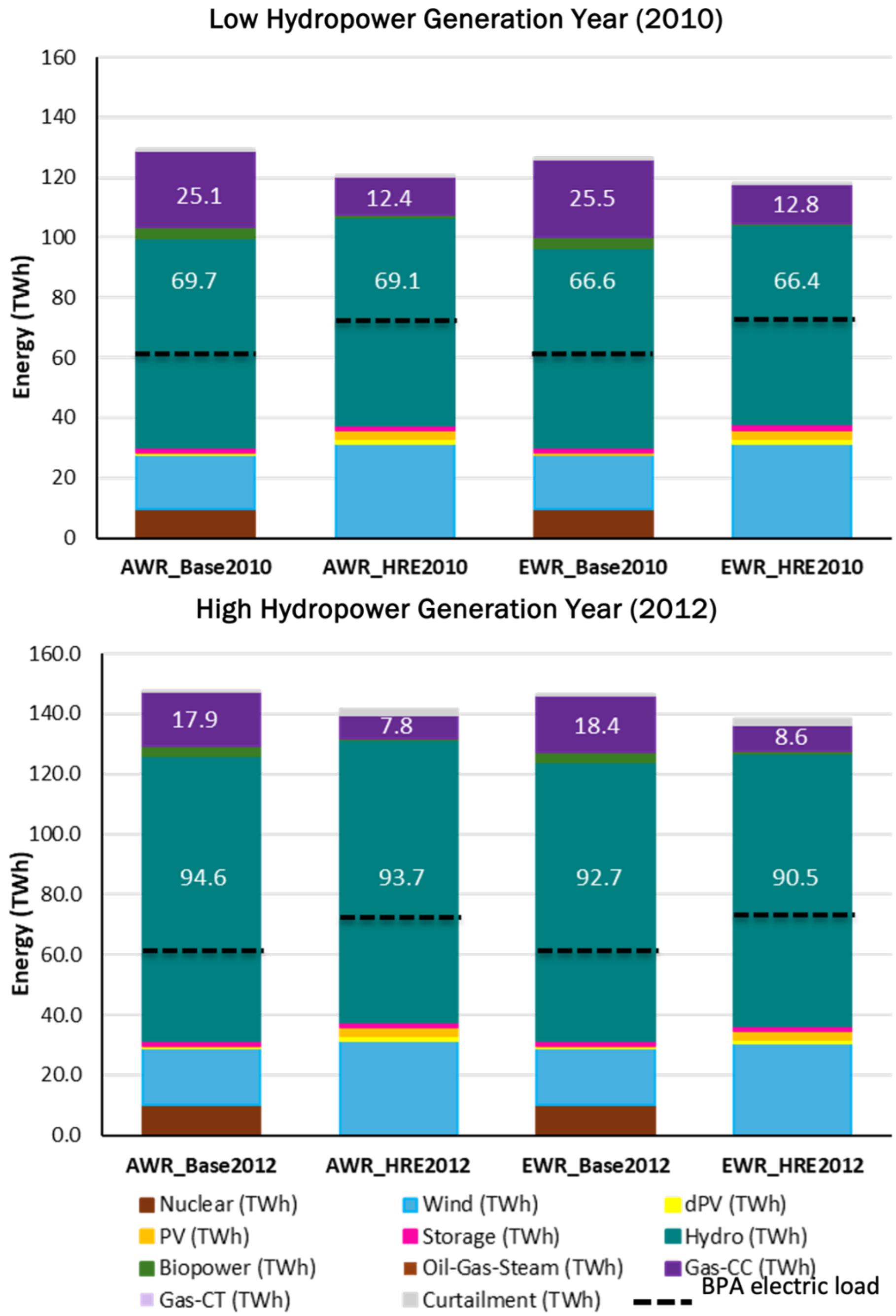

Figure 10. Generation Mix of Bonneville Power Association for Various Grid and Water Rule Scenarios

Figure 10 compares BPA generation mixes for water rules and grid scenarios for low and high hydropower generation years. The majority of CRB hydropower plants are located in BPA's service region (**Table 2**). In all years, BPA generation is substantially higher than BPA load (i.e., BPA is a net exporter), so differences in generation are primarily reflected as differences in exported energy. There is no nuclear generation in the higher renewable energy scenario due to retirements, and higher wind and solar generation. Combined-cycle gas generation is higher in low hydropower years than in high hydropower years, and higher for the base grid scenario than the higher renewable energy scenario. There is a relatively smaller difference in combined-cycle gas generation between the adjusted base water rules and ecosystem water rules scenarios, with slightly higher generation for the ecosystem water rules scenarios.

Daily Total Hydropower Generation Patterns

Figure 11 shows the Bonneville Dam and Grand Coulee hydropower plants' daily average generation values calculated by OASIS for 2008 -2013 across water rule scenarios. Daily generation values for these plants and others in the CRB were used to calculate daily total energy generated by CRB hydropower and simulated in the PLEXOS model as daily maximum energy limits.

For Bonneville and Grand Coulee plants' summer days, there are no significant changes in daily hydropower energy availability across the two water rules. However, from February to April, hydropower generation varies across two water rule scenarios. The results indicate that in dry years, dam water releases and generation are generally lower during winter and early spring and higher in late spring through summer. Daily generation values of other plants are illustrated in *Figure A-4* and *Figure A-5*.

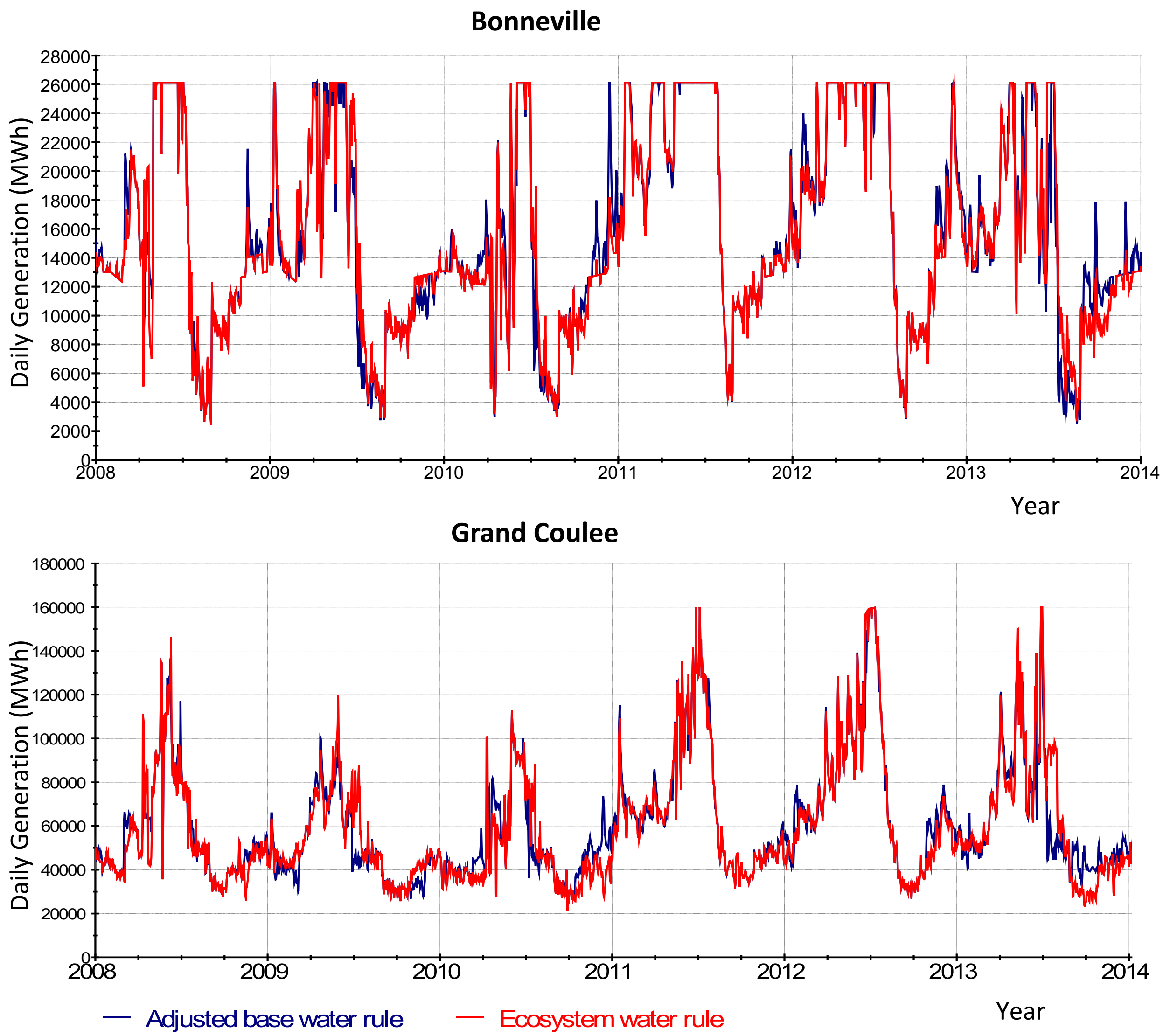

Figure 11 Bonneville and Grand Coulee Plants Daily Hydropower Generation Availability Values for Water Rule Scenarios

Total Daily Hydropower Generation for Different Water and Energy Scenarios

PLEXOS hourly economic dispatch results (**Figure 12** and **Figure 13**) reveal how CRB hydropower dispatches vary across weather conditions and renewable energy share grid scenarios. For different weather years, wind, solar, and hydropower generation, including CRB hydropower plants, differ in their relative contribution to total energy production, although the installed capacity remains the same across the system. As an example, **Figure 12** shows the Bonneville Dam power plant's daily hydropower generation patterns across the base grid and higher renewable energy grid scenario. Summer hydropower generation is higher than that of other periods for all years and grid scenarios. In all scenarios, annual runoff has a significant impact on daily generation, and that impact varies widely in different years.

The hydropower generation patterns in the high renewable energy grid scenario are more variable than the base power grid hydropower generation patterns. For example, the right side of the top row of **Figure 12** indicates that Bonneville summer generation in the high renewable energy grid scenario has more fluctuations compared to the base power grid scenario. There is similar generation variability in other years and power plant dispatch patterns.

Furthermore, hydropower generation varies across different water rule scenarios. In a high hydropower year, when summer days have maximum generation values, generation patterns are similar for all the scenarios. An example is 2012 in **Figure 13**. However, in low water periods and transition periods, hydropower generation varies more between scenarios. For example, in the years 2010 and 2013, Bonneville's daily generation differs significantly across the adjusted base water rules and ecosystem water rules scenarios. In these years, the ecosystem water rules maintain water in reservoirs during the winter and early spring (reducing generation) to support river flows during late spring and summer (increasing generation).

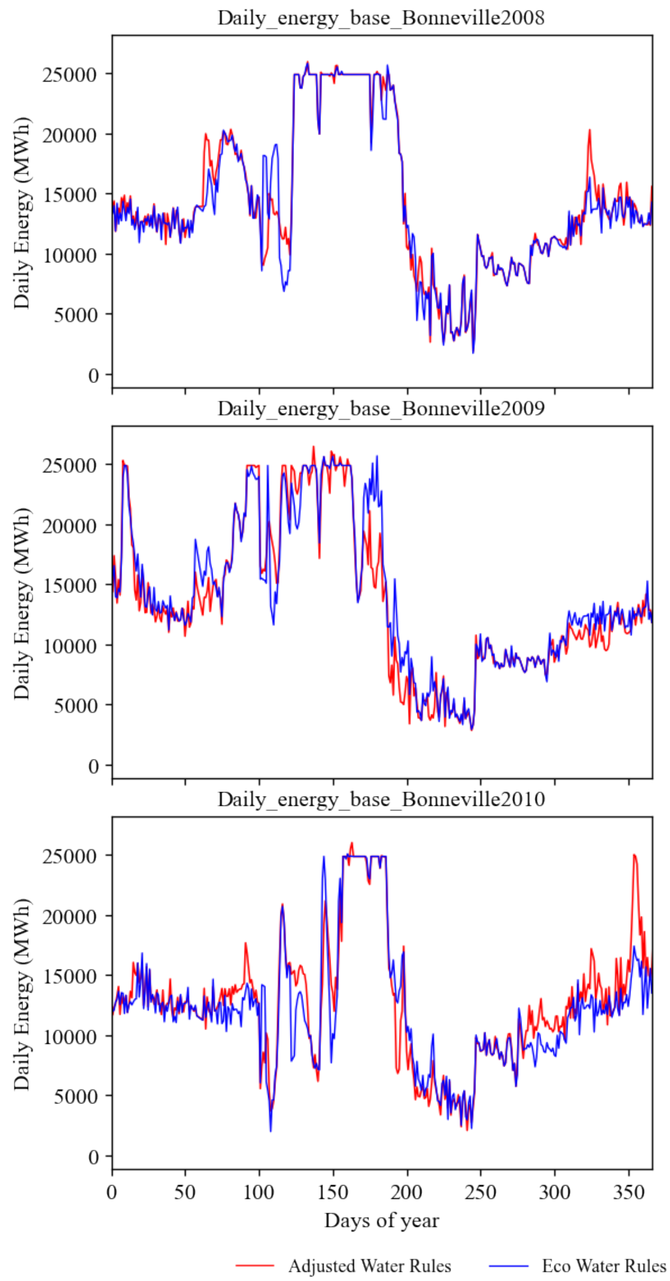

Figure 12. Bonneville Plant's Hydropower Generation for Water Rule and Grid Scenarios and Weather Years 2008, 2009, and 2010

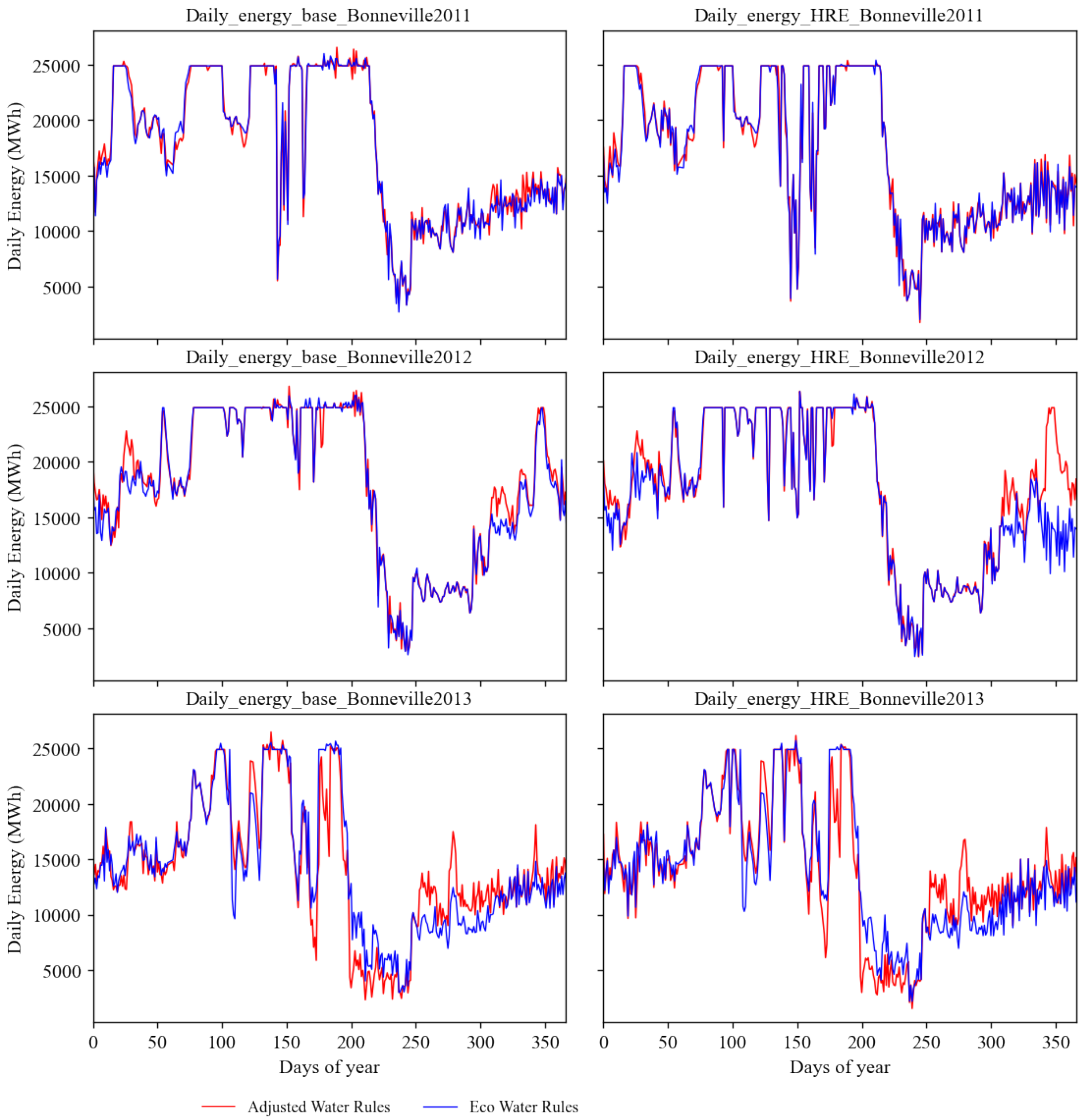

Figure 13. Bonneville Plant's Hydropower Generation for Water Rule and Grid Scenarios and Weather Years 2011, 2012, and 2013

Daily Average Diurnal Hydropower Generation Patterns

The study team calculated average diurnal hydropower generation shapes for four seasons. CRITFC selected these seasons based on the timing of the spring freshet and fish migration and spawning in the CRB water system

- Winter: January 1 – April 15
- Spring: April 16 – June 30
- Summer: July 1 – September 30
- Fall: October 1 – December 31

Figure 14 illustrates the Bonneville plant's seasonal average diurnal hydropower dispatch shapes as well as the maximum and minimum range of hydropower generation over each period. The blue solid line indicates the average hourly values over the season for base power grid infrastructure. The orange solid line indicates the average hourly values for the high renewable energy grid scenario over the season. The dashed blue and orange lines indicate the maximum values for each hour for the two scenarios. The dash-dot lines indicate the minimum values of the respective hours for each grid scenario. The dispatch shapes vary by season. For example, there are morning or evening peaks in the winter, evening peaks in the fall, and less variability during the spring. All four seasons' hydropower dispatch shapes have steep changes in the morning and evening, which become even steeper in the high renewable energy grid scenarios. For example, in the summer, the high renewable energy grid scenario's maximum and minimum operating capacities in the morning are higher than base grid scenario. In the afternoon, these values are lower than base grid scenario values. In the high renewable energy scenario, as solar generation share increases during the summer, daytime hydropower dispatch levels decrease, with sharp morning and evening operating capacity value changes. There are slight differences in seasonal hydropower dispatch shapes across the adjusted base water rules and ecosystem water rules scenarios.

Figure A 12,Figure A 13, Figure A 14 ,Figure A 15, Figure A 16 and Figure A 17 compare other hydropower plants' dispatch shapes for the two water rule scenarios. The plants include Dalles, Grand Coulee, John Day and Chief Joseph. Their dispatch patterns are similar to the Bonneville plant, with steep changes in the high renewable energy grid scenario compared to base grid scenario. In addition, there are slight differences in the average daily dispatch shapes across the water rule scenarios, including morning and evening average and maximum peak values and early morning off-peak values. Daily energy values do not differ significantly across the water rule scenarios. Slight differences in these values do not significantly impact generator scheduling and dispatch in Western Interconnection power grid simulations.

The difference between seasonal maximum and minimum operation capacity values depends on the power grid's net load variability, dam water release flexibility (such as the ability to add spill flows and turbine flows), and the minimum flow requirement of each dam (Figure A-6, Figure A-7, Figure A-8). During the spring, most of the plants meet their minimum release requirements fully by spill release (Figure A-8, Figure A-10). Then, daily turbine flow volumes have flexibility to increase to meet power grid requirements (Figure A-9, Figure A-11).Similar to system operators, production cost models dispatch flexible hydropower plants at maximum capacity during peak periods and at minimum capacity during off-peak periods. Therefore, spring generation spans a wider range between the maximum and minimum operation capacity of the power plants. The study team assumed that the technical minimum operation capacities of hydropower plants are zero. Since the model already accounts for the minimum flow requirement, the minimum operating capacities only depend on the technical parameters of the plants. In early summer, spill releases meet minimum release requirements. Later in the summer, turbine flows partly meet minimum flow requirements. Hence, on average, minimum operating capacities are greater than zero. In the winter and fall, minimum release requirements are met by both spill and turbine flows. Hence, hydropower generation flexibility is lower, and there is a smaller operating capacity range.

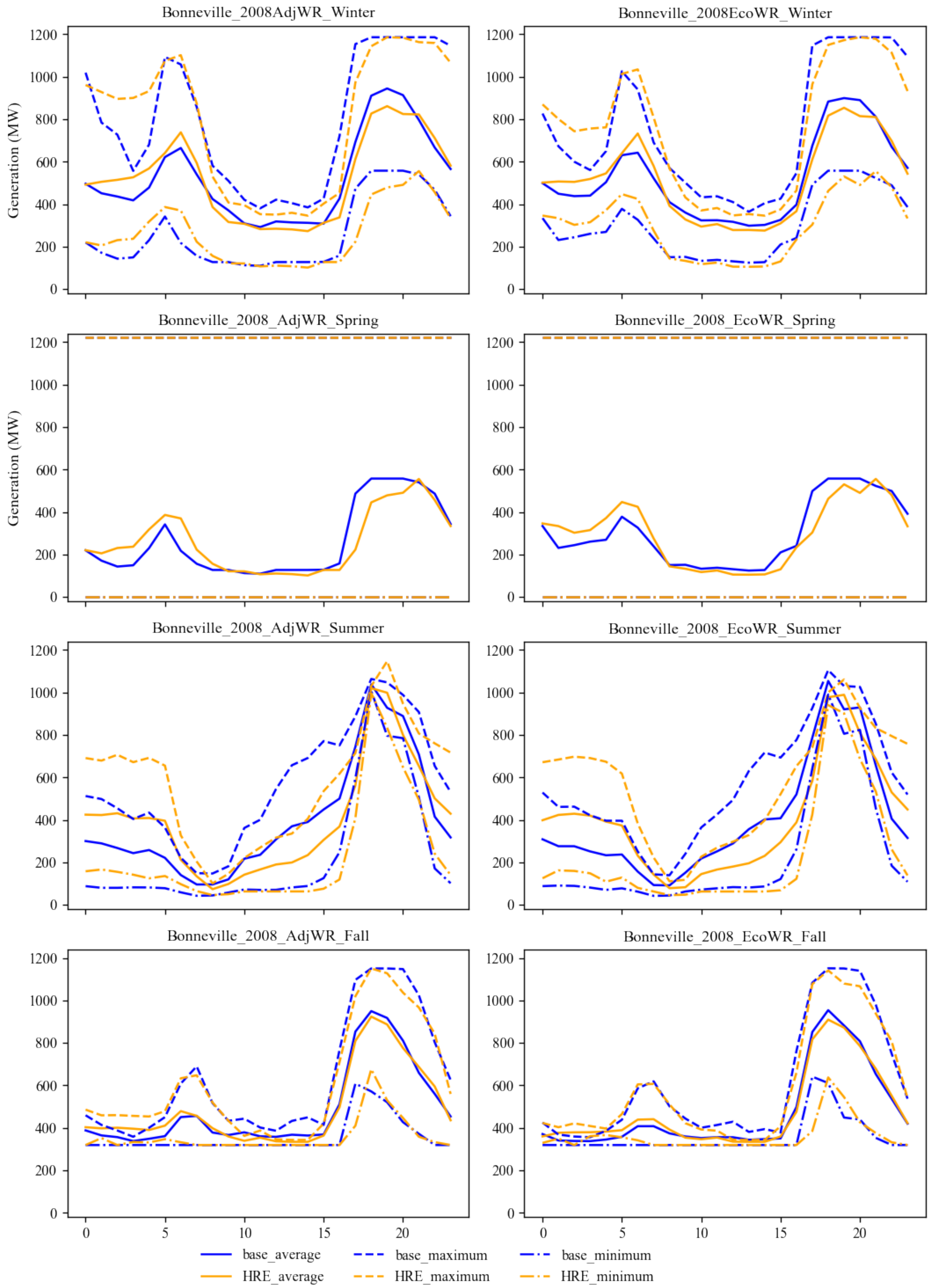

Figure 14 Seasonal Average Diurnal Hydropower Dispatch Patterns of Bonneville Plant

Hydropower Dispatch Variation

The modeling results revealed a higher variability of hydropower dispatch in the high renewable energy grid scenario. To better understand hydropower's role in grid operations, the study team selected two time windows (May 15–25 of weather year 2008 and April 13–17 of weather year 2012) to examine BPA's hourly generation dispatches across the base and high renewable energy grid scenarios.

Figure 15 and **Figure 17** show BPA's hourly dispatches in these two periods, along with demand. BPA hydropower plants have a total capacity of 28 GW and include Grand Coulee, Chief Joseph, Libby, McNary, John Day, Dalles, and Bonneville. Nuclear power in BPA's service territory will be retired in the higher renewable energy scenario, and new wind and solar plants will increasingly contribute to BPA generation. BPA is a net exporter, with generation exceeding electricity demand in the base and high renewable energy grid scenarios.

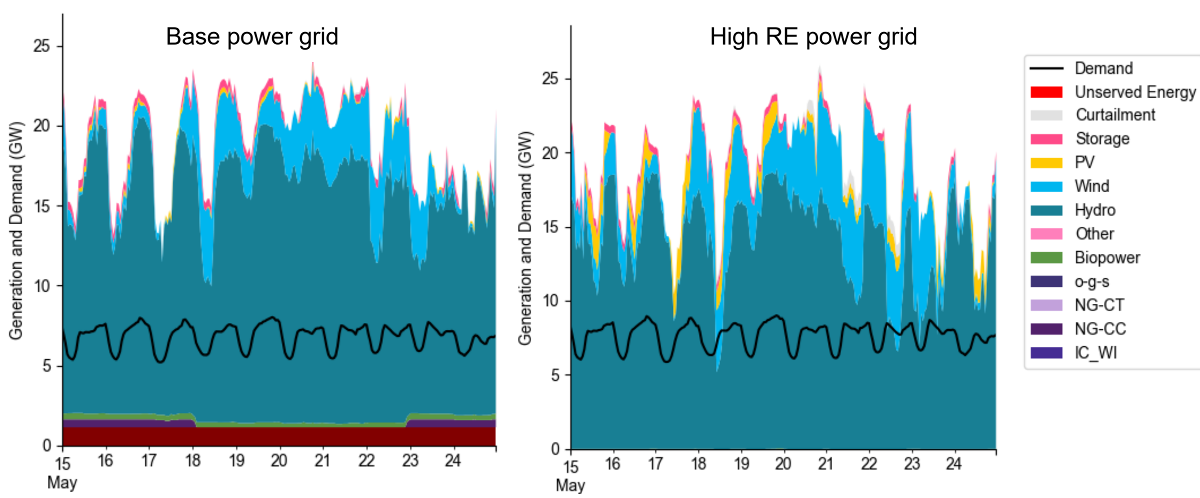

Figure 15. BPA Hourly Generation Dispatch during May 15–25 for Adjusted Base Water Rules Scenario and Weather Year 2008

Figure 16 shows BPA's hydropower and VRE generation. Hydropower generation balances short-term wind and solar generation variability, in addition to hydropeaking. Since wind and solar contribute more to the grid in the high renewable energy scenario, the variability of net load is also higher. For example, from May 18 to May 19, hydropower generation decreases when VRE generation increases. Similar patterns were observed with other balancing authorities.

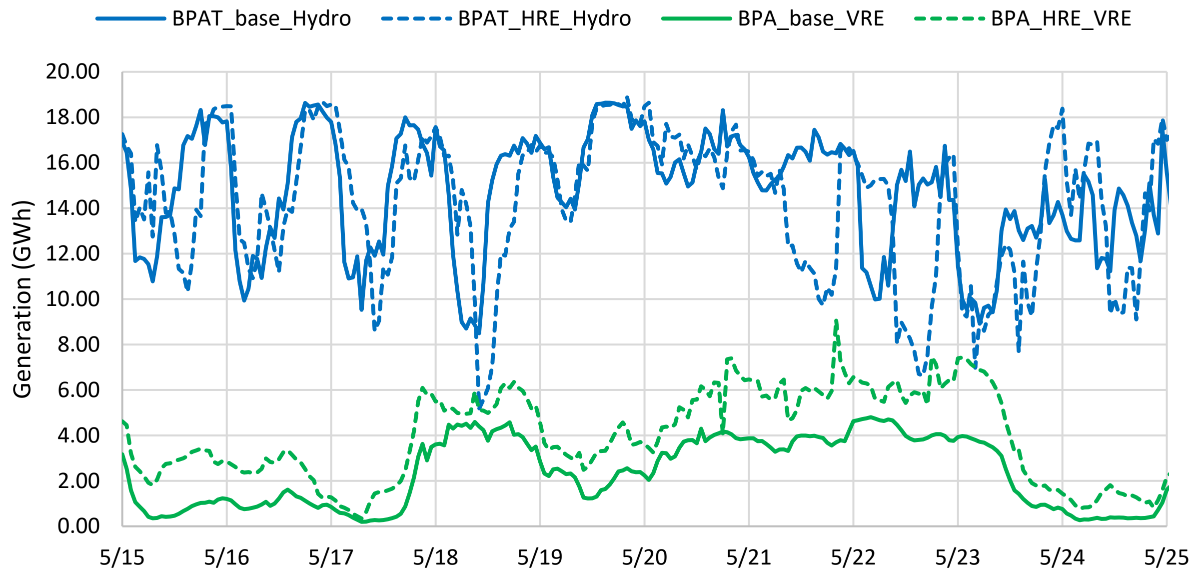

Figure 16. BPA Hydropower and VRE Generation during May 15–25 for Adjusted Base Water Rules Scenario and Weather Year 2008

The study team also examined hydropower and other generator hourly dispatches for the ecosystem water rules scenario, and there was not a significant difference with the adjusted base water rule scenario. For example, in weather year 2012 for the two water rules scenarios, April 13 to 17 dispatches have minor differences (**Figure 17**). These observations suggest that the constraints in the ecosystem water rules scenario do not restrict hydropower's hourly generation variability and flexibility to follow net load and balance VRE.

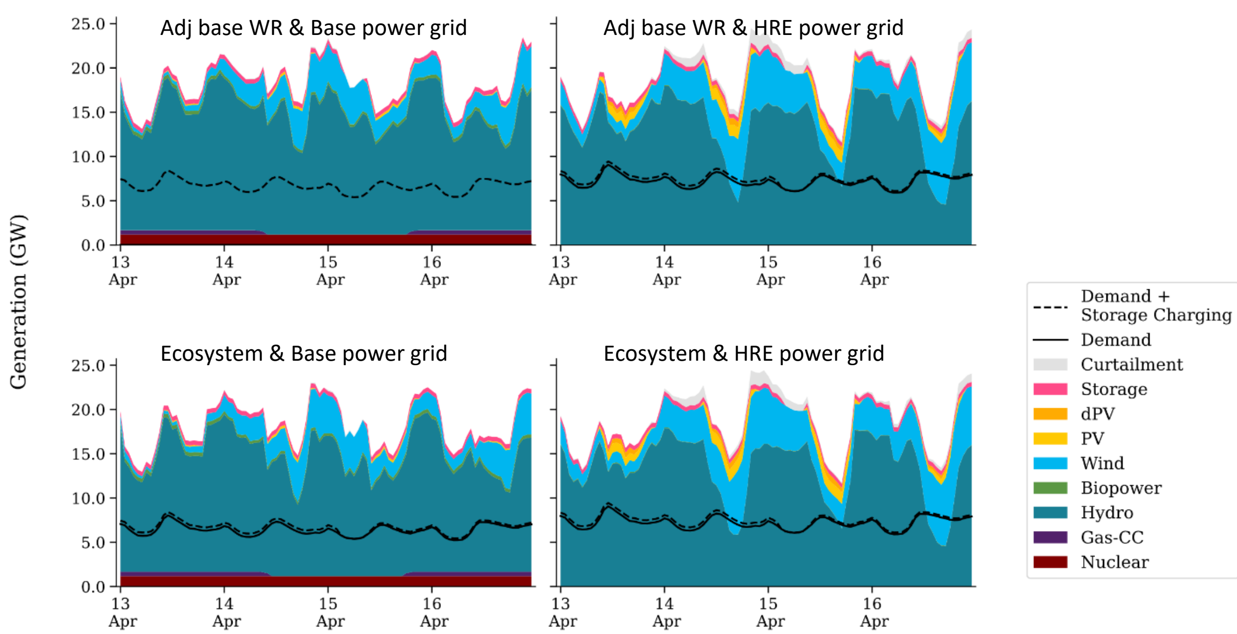

Figure 17. BPA Generator Dispatches for Water Rule and Grid Scenarios in Weather Year 2012

Renewable Curtailment

Hydropower provides grid flexibility services and can balance VRE generation variability as illustrated in Figure 15, Figure 16 and Figure 17. Although dispatch shapes do not differ in the selected time frames, different water rules could limit hydropower flexibility. As a result, VRE generation can be curtailed. Figure 18 compares BPA VRE curtailment for the adjusted base water rules and ecosystem water rules scenarios and base (top panel) and high renewable energy grid (bottom panel) scenarios. There is no major difference between total VRE curtailment values across the two water rule scenarios. (Note that in this figure, the scale of the right y-axis is larger than the scale of the left y-axis.). Figure A 19, Figure A 20, Figure A 21, Figure A 22, and Figure A 23 compare VRE curtailment of Chelan County PUD, Grant County PUD, City of Tacoma, department of Public Utilities, PacifiCorp West and Portland General Electric Company for high renewable grid scenario and different water rule and weather scenarios.

A significant portion of curtailment would happen during summer months when hydropower generation and VRE generation are higher than electricity demand. During dry years such as 2009 and 2010, hydropower generation in June and July is slightly higher in the ecosystem water rules scenario than in the adjusted base water rules scenario. Curtailment values are also higher in the ecosystem water rules scenario during these two months.

In addition, there are significant differences in VRE curtailment across different weather years. For example, VRE curtailment is higher in 2011 and 2012 than in other years. This is likely because there was relatively high annual runoff and more hydropower production. VRE curtailment values are also higher in the high renewable energy grid scenario.

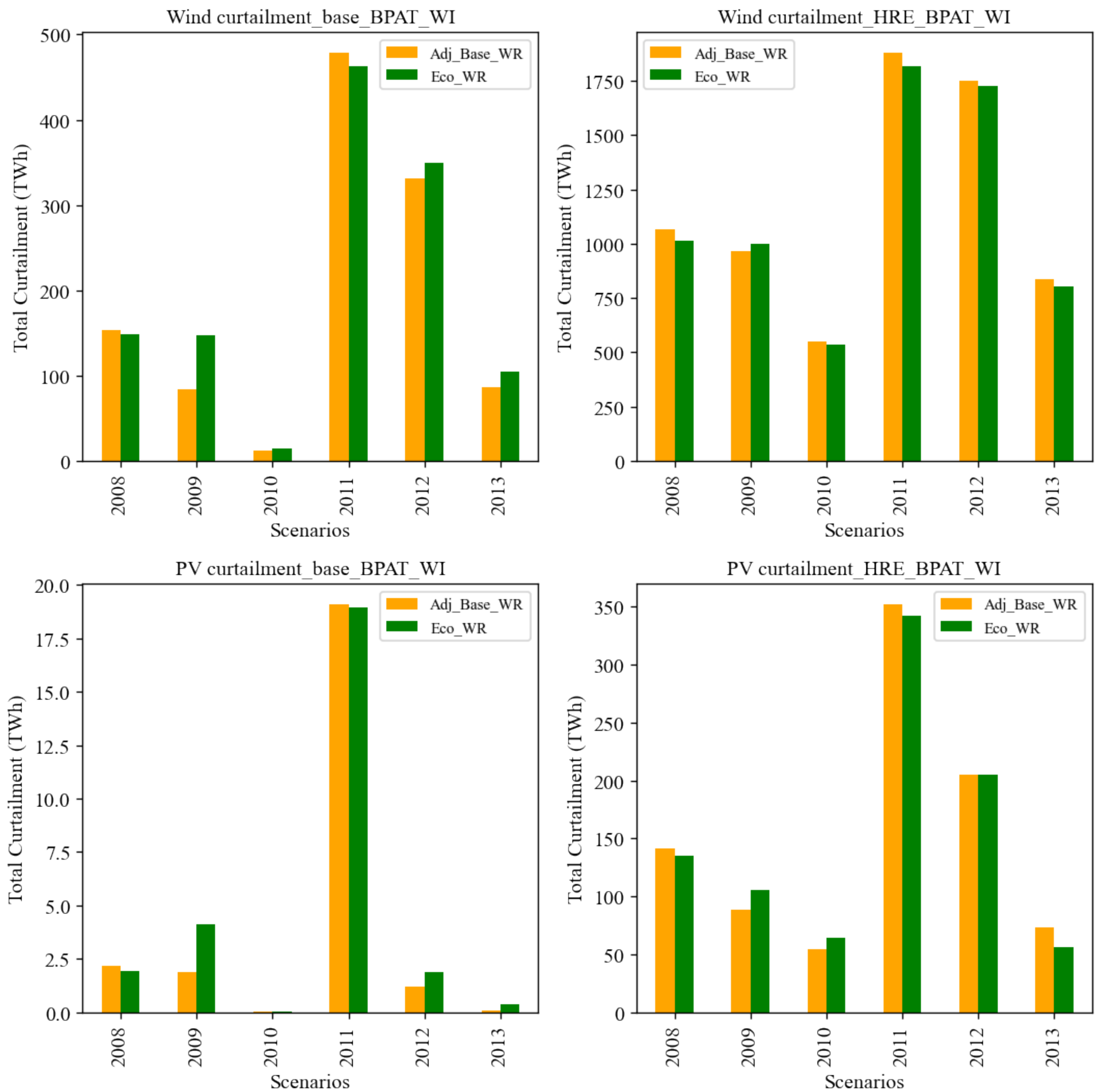

Figure 18. Wind and Solar Power Curtailment for Various Water, Grid, and Weather Scenarios

System Operation Cost

Total system operation costs include generation costs, variable operations and maintenance costs, and reserve costs. The generation costs include fuel, generator start-up and shutdown costs, and generator ramp-up and ramp-down costs. Capital costs for generators and other grid infrastructure are not included in system operation costs. The study team compared the system operation cost of BPA and the 14 balancing authorities of the Western Interconnection across the water rules and grid scenarios. In **Table 5**, BPA's total operating costs are compared across weather years, water rules, and grid scenarios. Cost differences across water rule scenarios are less significant compared to cost differences across different weather years. The operating costs in higher hydropower generation years (such as 2011 and 2012) are lower than operating costs in other years.

Table 5 and **Table 6** show how operations costs in the high renewable energy scenario are significantly lower than in the base power grid scenario. This is expected since VRE plants have lower operating costs than other types of generators. For example, in weather year 2012, the high renewable energy scenario reduced BPA's operations costs by approximately 70%. The operations costs for the focus region in this study (**Table 2**) were reduced by 30%, and the Western Interconnection operations cost were reduced by nearly 20%. The HRE grid scenario has a 55% renewable energy contribution with zero fuel cost (**Figure 10**). In addition, thermal generation with higher generation costs, such as combined-cycle gas and combustion turbines, would be retired and replaced by renewable power and other technologies, significantly reducing system operations costs.

Table 5 and **Table 6** also show that there is significant operation cost variability between years, resulting from factors such as weather variability and electricity system load. For example, in the base grid scenario, in 2010 (the highest average cost year) BPA operations costs are 29% higher than in 2011 (the lowest average cost year) for both the adjusted base water rules and the ecosystem water rules scenarios. In the HRE grid scenario, BPA costs are 62% and 66% higher in 2010 than in 2011 for the adjusted base water rules and ecosystem water rules scenarios, respectively. For the study's full focus region, operations costs are 18% higher in 2010 than in 2011 for the base grid scenario in both the adjusted base water rules and ecosystem water rules scenarios. For the HRE grid scenario, operations costs are 31% and 32% higher in 2010 than in 2011 for the adjusted base water rules and ecosystem water rules scenarios, respectively.

Results also indicate that BPA operations cost in the ecosystem water rules scenario range from 4% lower than in the adjusted base water rules scenario to 11% higher compared with adjusted Water Rules scenario, averaging 2% higher (about 1% for the base grid scenarios and about 3% for the high renewable energy scenarios). Operations costs in the adjusted base water rules scenario is lower than in the ecosystem water rules scenario in all years except 2009 and 2013. As noted in **Table 4** and **Figure *9***, hydropower generation with ecosystem water rules in year 2009 is higher than with the adjusted base water rules. Operations costs with the ecosystem water rules in year 2009 are lower than with the adjusted base water rules scenario. For the 14 balancing authorities, the operation cost increments for the base and high renewable energy grid scenarios are around 1% for the ecosystem water rules and adjusted base water rules scenarios (for both the base grid and high renewable energy scenarios).

Table 5. BPA Region Total Operations Cost

Scenario	Operating Cost 2008 (M$)	Operating Cost 2009 (M$)	Operating Cost 2010 (M$)	Operating Cost 2011 (M$)	Operating Cost 2012 (M$)	Operating Cost 2013 (M$)
Adj WR, base grid	1064.5	1019.1	1124.5	873.9	873.6	1046.2
Eco WR, base grid	1075.7	1007.7	1139.2	880.2	900.6	1040.6
Adj WR, HRE grid	359.8	367.2	417.8	257.2	261.6	361.2
Eco WR, HRE grid	373.2	351.9	432.4	261.0	291.3	364.5

Note: "Adj WR" refers to adjusted base water rules; "Eco WR" refers to ecosystem water rules; "HRE grid" refers to high renewable energy grid scenario.

Table 6. Total Operations Cost, Focus Region (14 Balancing Authorities)

Scenario	Operating cost 2008 (M$)	Operating cost 2009 (M$)	Operating cost 2010 (M$)	Operating cost 2011 (M$)	Operating cost 2012 (M$)	Operating cost 2013 (M$)
Adj WR, base grid	5187.2	5147.5	5474.1	4620.7	4605.1	5179.4
Eco WR, base grid	5240.1	5113.6	5532.5	4699.7	4673.8	5180.3
Adj WR, HRE grid	3638.9	3812.0	4149.7	3169.4	3300.6	3722.6
Eco WR, HRE grid	3689.1	3773.7	4202.8	3183.8	3304.3	3750.2

Note: "Adj WR" refers to adjusted base water rules; "Eco WR" refers to ecosystem water rules; "HRE grid" refers to high renewable energy grid scenario.

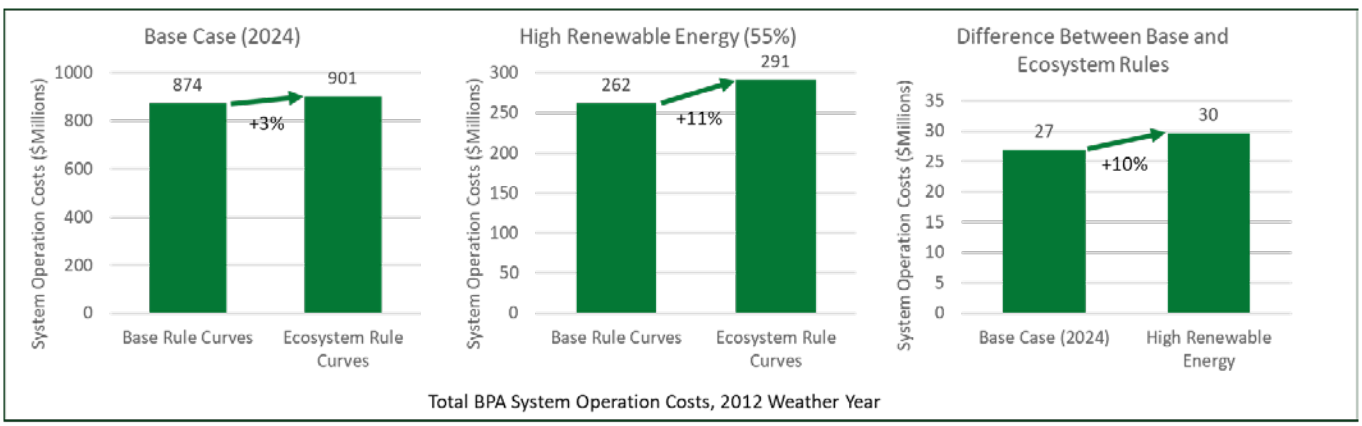

Figure 19. BPA Region System Operation Cost for Three Water Rule and Grid Scenarios for year 2012

Local Marginal Energy Prices

Nodal-level, local marginal energy prices (LMPs) represent the wholesale price of energy at a particular location and time. LMPs partially determine both the potential revenue from selling energy and the potential cost of buying energy for consumers. They are calculated based on the marginal generator's short-run marginal cost, transmission losses, and transmission congestion between balancing authorities. In addition, changes in LMP values across scenarios and weather years indicate how multiple factors would impact the LMP values. **Figure 20** shows the energy price duration curves in the BPA region across two water rule scenarios and two grid scenarios for high and low hydropower generation years. **Figure 21** illustrates the monthly average diurnal price shapes for the BPA region. Generally, the high renewable energy grid scenario has high- and low-price hours compared to the base grid scenario. The low LMPs come from low-cost marginal generators during the daytime, with higher prices occurring in the evening peak period. The ecosystem water rules scenario has more high- and low-price hours compared to the adjusted base water rules scenario.

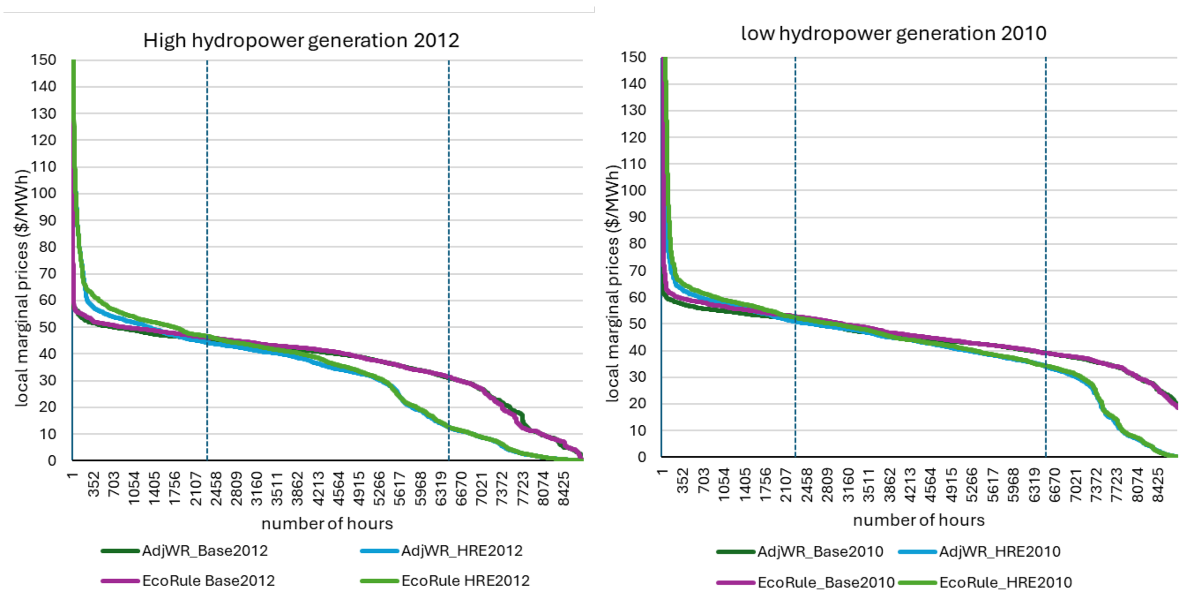

Figure 20. BPA Region Local Marginal Price Duration Curves for Water Rules and Grid Scenarios

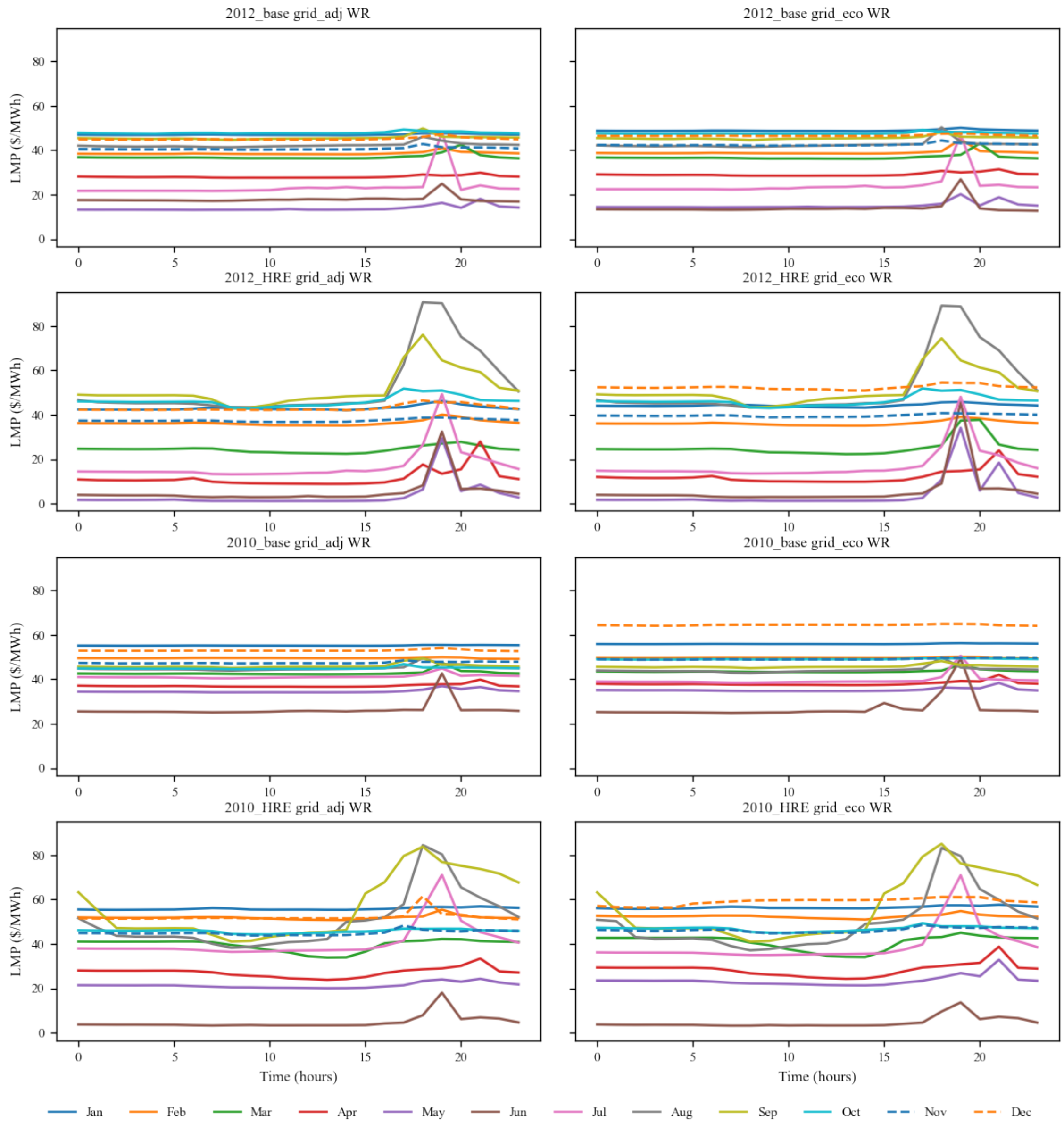

Figure 21. BPA Region Local Marginal Price Monthly Average Diurnal Shapes for Water Rule and Grid Scenarios

Table 7 illustrates average LMP values across water rule and power grid scenarios for different weather years. Average LMP values are lower for the high renewable energy grid scenario compared to the base grid scenario. LMP values are higher in low hydropower generation years (such as 2010) than in high hydropower generation years (such as 2012). The average LMP values of the adjusted base water rules scenario are lower than in ecosystem water rules scenario. In addition, LMP values in the high renewable energy scenario are higher in the ecosystem water rules scenario than in the adjusted base water rules scenario. The changes in LMPs indicate how zero-marginal price hydropower and other renewable energy contributions impact the prices. LMPs in the base power grid scenario and low hydropower years are higher because the contribution from thermal generation with higher marginal prices is greater.

Table 7. BPA Region Average Local Marginal Prices Across Scenarios

Scenario	LMP 2008 ($/MWh)	LMP 2009 ($/MWh)	LMP 2010 ($/MWh)	LMP 2012 ($/MWh)	LMP 2013 ($/MWh)
Adj WR, base grid	41.58	41.50	44.43	36.28	41.96
Eco WR, base grid	41.95	40.56	45.86	36.67	42.00
Adj WR, HRE grid	36.11	38.52	41.49	31.53	37.75
Eco WR, HRE grid	36.38	37.89	42.52	32.83	37.87

Note: “Adj WR” refers to adjusted base water rules; “Eco WR” refers to ecosystem water rules; “HRE grid” refers to high renewable energy grid scenario.

Power Grid Reliability Comparison

Unserved Energy

The study team did not find unserved energy hours for the study focus region on any of the water rule and grid scenarios.

Transmission Congestion

Power flow is constrained by the thermal limits of transmission lines, and the production cost model simulates power flow limits with a penalty. The model results include hours with transmission congestion, aggregating the number of hours in which power flows exceed the maximum line limits. The study team did not find a significant difference in transmission congestion across the two water rule scenarios.

Conclusion

This study used two models to assess the impact of varying water release schedules in the CRB. The goal was to evaluate how changes in hydropower scheduling can reduce ecological impacts to the region's salmon populations. The study evaluated the impact of ecologically informed water release scheduling rules (called "ecosystem water rules" in this study) on two grid scenarios (current and higher renewable energy levels), using six weather and hydrology years (2008-2013) for each scenario. The ecosystem water rule curves mimic historical spring runoff from snowmelt to provide fuller, more stable reservoir elevations that aid the migration of juvenile salmon and steelhead smolts.

The study indicated that some changes could be made to CRB hydropower operations to improve conditions for fish with limited impacts on electricity system costs and reliability. The analysis revealed the following:

- Hydropower dispatch patterns varied across grid scenarios, weather years, and water rule scenarios. There were significant differences across grid scenarios and weather years in parameters such as ramping and morning and daily hydropower generation.
- Water rule scenarios did not change daily hydropower plant generation significantly. As a result, grid operations costs, LMPs, grid reliability metrics (such as unserved energy, transmission congestion, reserve failures, and renewable curtailment) do not change significantly either. The ecological scheduling constraints did not substantially reduce the ability of hydropower to follow net load curves even at higher renewable energy levels.
- Power grid operations costs for the study focus region of the Pacific Northwest are about 1% higher on average for the ecosystem water rule scenarios versus the adjusted base water rules scenarios (for both the base grid and high renewable energy scenarios). BPA operations cost in the ecosystem water rules scenario range from 4% lower than in the adjusted base water rules scenario to 11% higher, averaging 2% higher (about 1% for the base grid scenarios and about 3% for the high renewable energy scenarios).
- Operations costs vary more between years (due to factors such as weather variability and electricity system load) than between water rules scenarios. For example, in the base grid scenario, in 2010 (the highest average cost year) Pacific Northwest region operations costs are 18% higher than in 2011 (the lowest average cost year) for both the adjusted base water rules and the ecosystem water rules scenarios. In the HRE grid scenario, Pacific Northwest region costs are 31% and 32% higher in 2010 than in 2011 for the adjusted base water rules and ecosystem water rules scenarios, respectively.
- Operations costs for the high renewable energy grid scenarios is on average around 50% lower than for the base grid scenarios for both the base water rules and ecosystem water rules scenarios.
- While modeling found the potential for slight increases in total generation costs and LMPs for the ecosystem water rules relative to the base water rules, these increases should be weighed against the value of reducing ecological impacts, which was outside the scope of this study.
- This study did not consider the impact of the broader range of changes CRITFC recommends to align CRB hydropower operations with the needs of fish in the region. Further research is needed to investigate this issue.

- This study does not consider the optimal infrastructure buildout changes for the water rule scenarios. However, the relatively minor differences in daily hydropower generation across the water rule scenarios suggest that the differences in optimal infrastructure build-out would also be minor. Further research is needed to investigate this issue.
- The study did not consider specific power contracts that constrain generator dispatches and transmission use. These constraints could potentially lead to different results.

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Appendix A

Hydropower Monthly Energy

Figure A-1, Figure A-2 and Figure A-3 illustrate CRB hydropower energy from the OASIS model results, which show variability across water rules and weather years. Late spring and early summer months show higher hydropower generation, which could be noticed across total CRB hydropower, Bonneville, and Grand Coulee power plants.

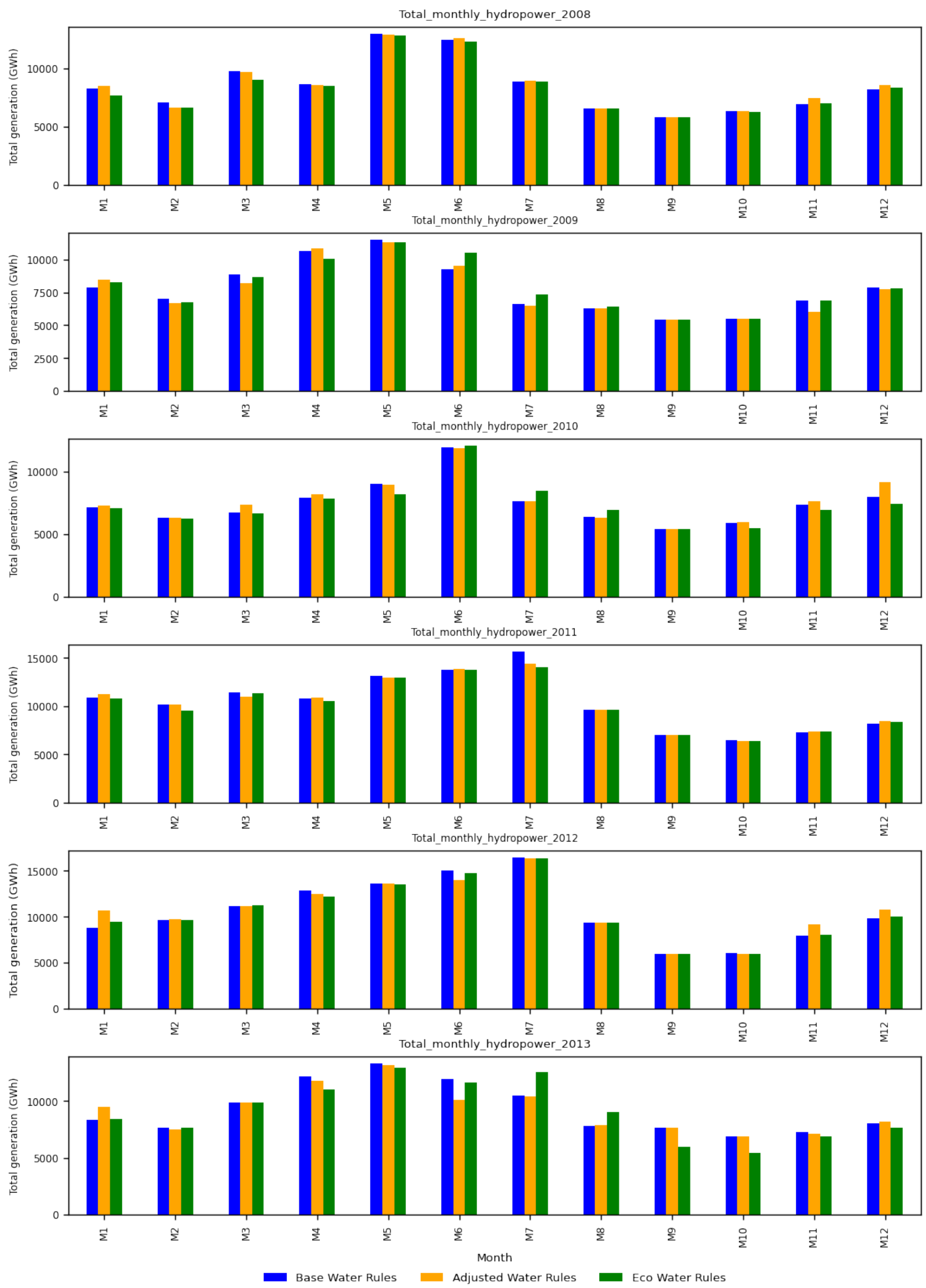

Figure A-1. Monthly Hydropower Generation Variability for Various Weather Years and Water Rule Scenarios

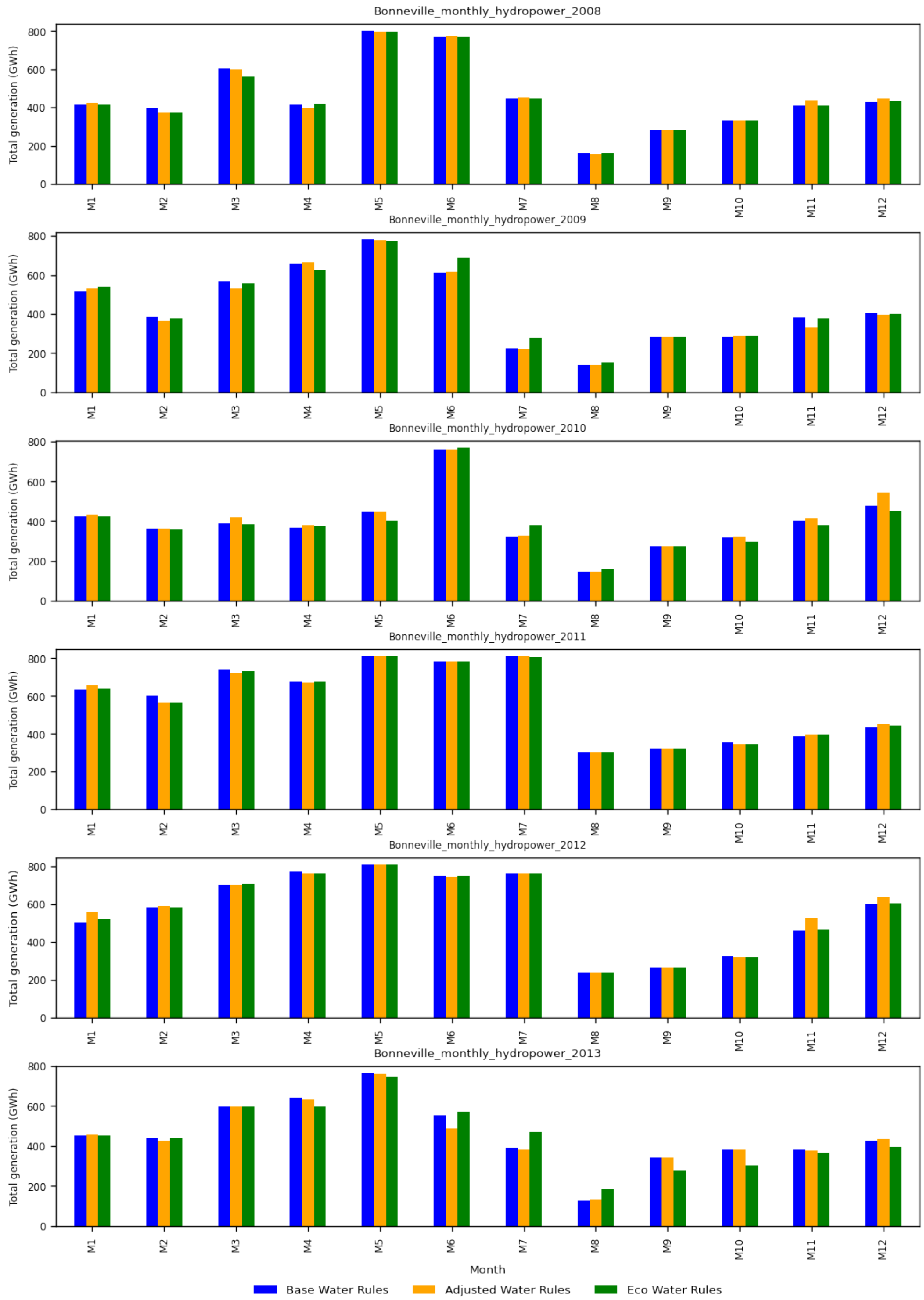

Figure A-2. Bonneville Hydropower Plant Monthly Generation for Various Water Rules and Weather Scenarios

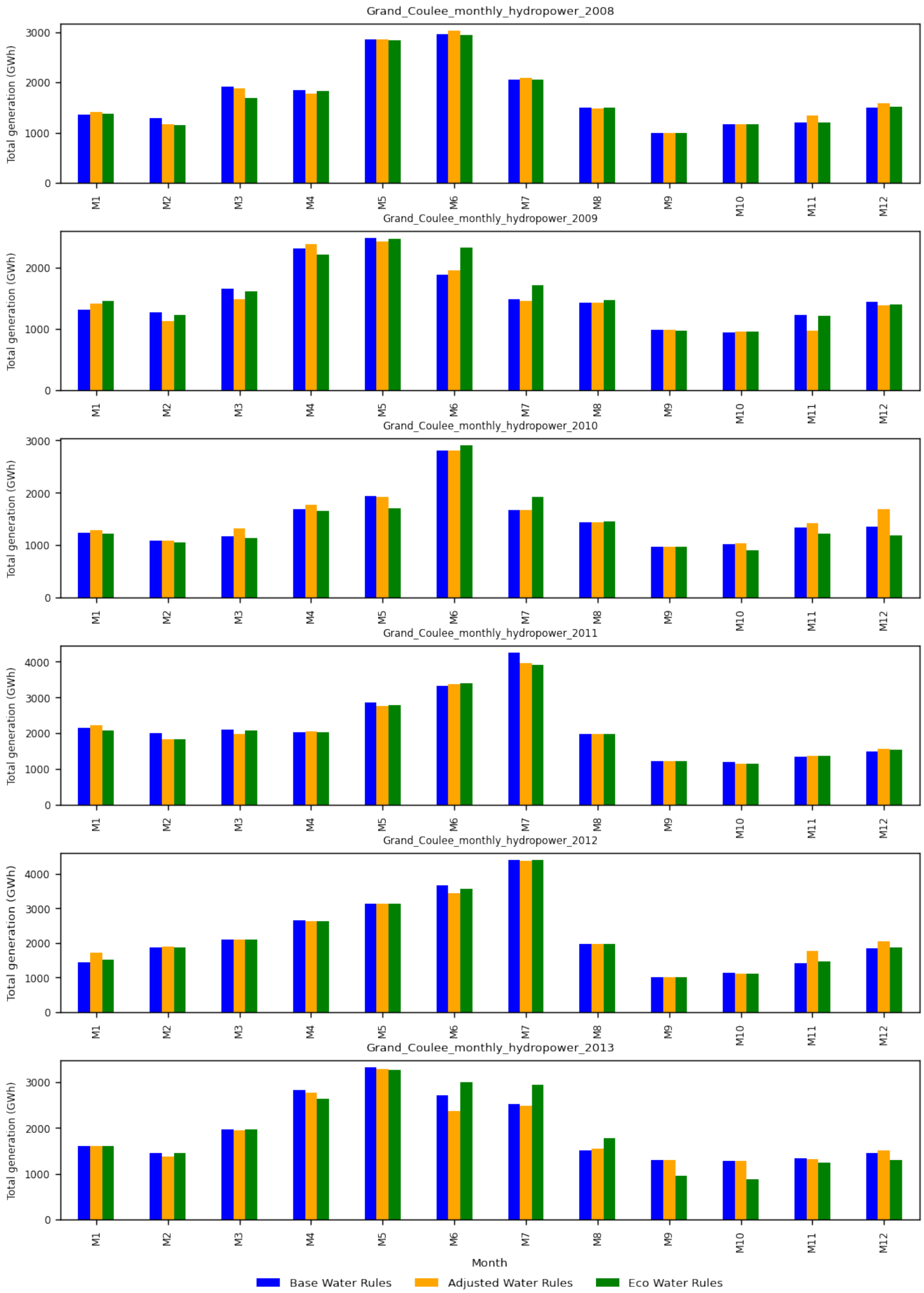

Figure A-3. Grand Coulee Hydropower Plant Monthly Generation for Various Water Rules and Weather Scenarios

Hydropower Daily Energy

Figure A-4 and Figure A-5 illustrate daily hydropower generation for adjusted base and ecosystem water rules. Hydropower generation of dry weather years such as 2009 and 2010 has differences in the water rule scenarios.

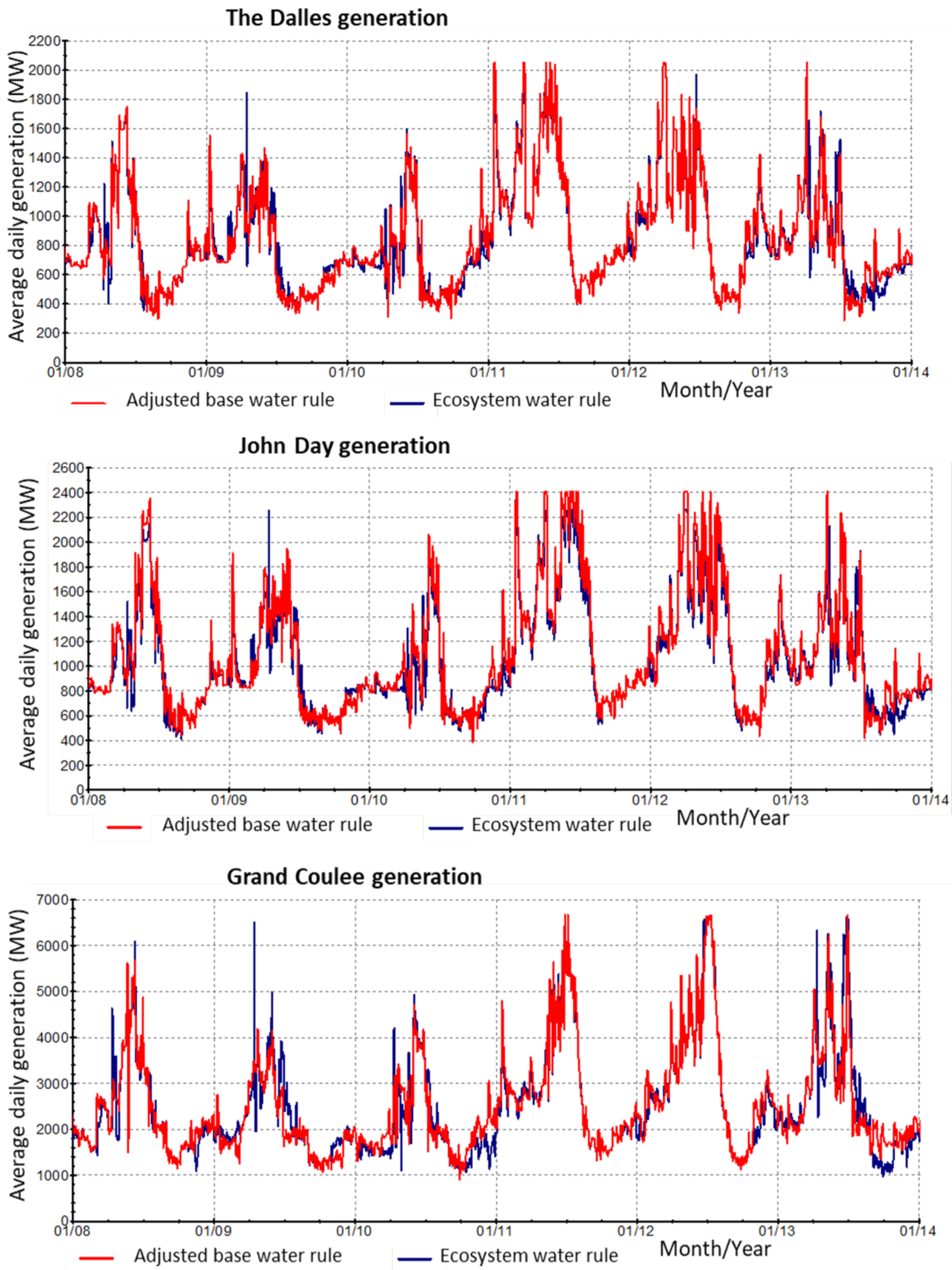

Figure A-4. Average Daily Generation of Dalles, John Day, and Grand Coulee power plants

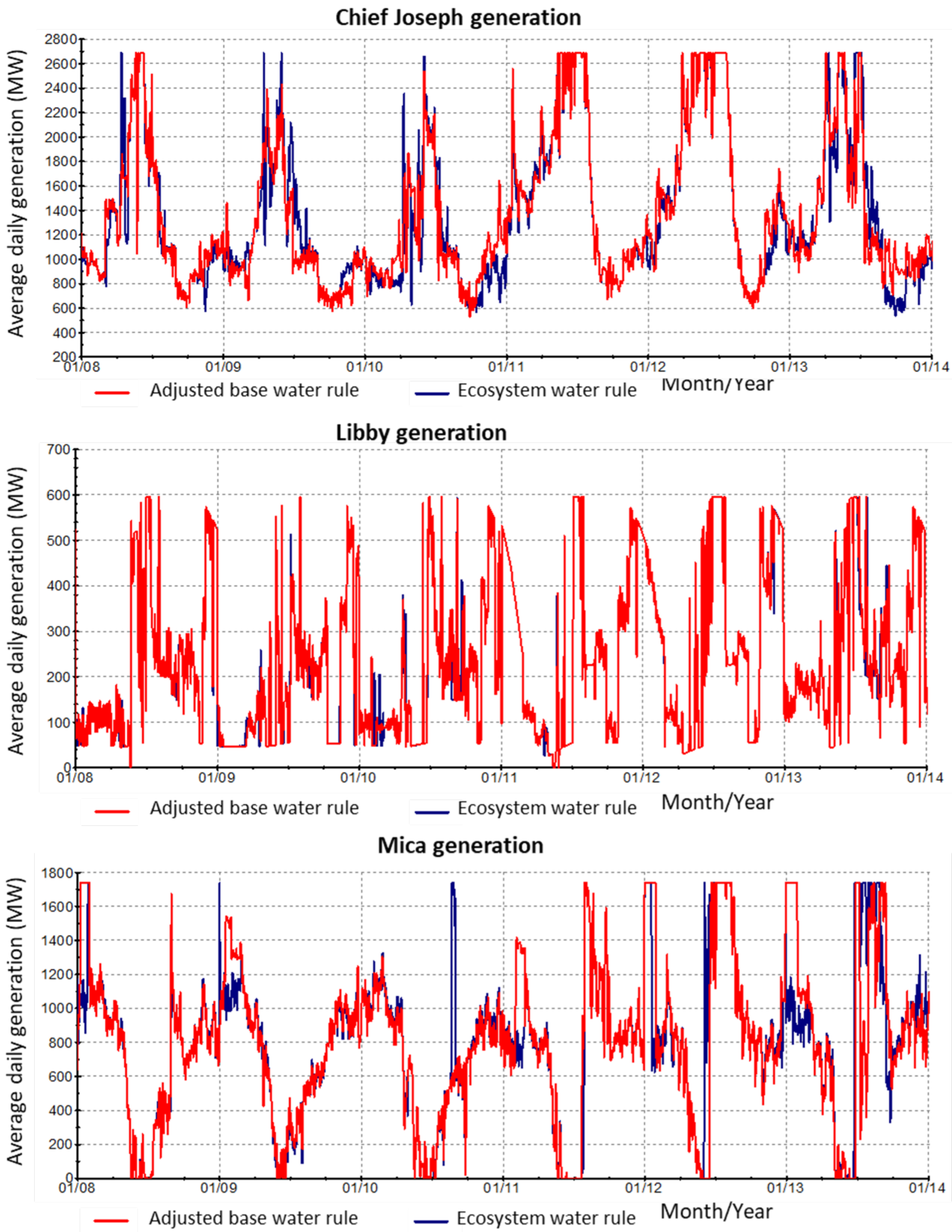

Figure A-5. Average Daily Generation of Chief Joseph, Libby, and Mica Power Plants

Minimum Environmental Flow Modeling

Table A-1. Environmental Flow Values for Columbia River Hydropower Plants

Project	Minimum Flow (instantaneous limit unless noted as daily average)	Maximum Ramp Rate (expressed as reservoir elevation and/or change in discharge rate	Source
Bonneville	80 kcfs (instantaneous) and 100 kcfs (daily average)	Apr-Sep: 1.5ft/hr and 4ft/day; Oct-Mar: 3ft/hr and 7ft/day (tailrace elevation). Additionally, tailwater elevation must be maintained in the following ranges: Nov-Dec: 11.3-12 feet, Jan-Apr10: ~11.3-11.5 ft	2023 Fish Passage Plan; 2023 Water Management Plan; Oasis Model Documentation
The Dalles	Dec-Feb: 12.5 kcfs; Mar-Nov: 50 kcfs	3ft/hr (tailrace elevation) and 150 kcfs/hr	2023 Fish Passage Plan; 2023 Water Management Plan
John Day	Dec-Feb: 12.5 kcfs; Mar-Nov: 50 kcfs	3ft/hr (tailrace elevation) and 200 kcfs/hr	2023 Fish Passage Plan; 2023 Water Management Plan
McNary	Dec-Feb: 12.5 kcfs; Mar-Nov: 50 kcfs	1.5ft/hr (tailrace elevation) and 150 kcfs/hr	2023 Fish Passage Plan; 2023 Water Management Plan
Priest Rapids	Oct15-Nov30: **Maximum** Flow Limit of 70 kcfs; Dec-Jun: Highest flow recorded during Oct15-Nov15 period is applied as the **Minimum** Flow (this is a simplification – is more complex in reality year-to-year)	Not provided	Vernita Bar Agreement; Oasis Model Documentation
Chief Joseph	35 kcfs (daily average)		2023 Water Management Plan
Grand Coulee	Not provided	1.5ft/day (forebay elevation)	2023 Water Management Plan
Libby (Kootenai R)	May15-Aug31: 6 kcfs (daily average); Sep1-May14: 2 kcfs (instantaneous) and 3 kcfs (daily average)	Not provided	2023 Water Management Plan; Oasis Model Documentation

Ice Harbor (Snake R)	Dec-Feb: 0 kcfs; Mar-Jul: 9.5 kcfs; Aug-Nov: 7.5 kcfs	1.5ft/hr (tailrace elevation) and 20 kcfs/hr	2023 Fish Passage Plan; 2023 Water Management Plan
Lower Monumental (Snake R)	Dec-Feb: 0 kcfs; Mar-Nov: 11.5 kcfs	1.5ft/hr (tailrace elevation) and 70 kcfs/hr	2023 Fish Passage Plan; 2023 Water Management Plan
Little Goose (Snake R)	Dec-Feb: 0 kcfs; Mar-Nov: 11.5 kcfs	1.5ft/hr (tailrace elevation) and 70 kcfs/hr	2023 Fish Passage Plan; 2023 Water Management Plan
Lower Granite (Snake R)	Dec-Feb: 0 kcfs; Mar-Nov: 11.5 kcfs	1.5ft/hr (tailrace elevation) and 70 kcfs/hr	2023 Fish Passage Plan; 2023 Water Management Plan

Minimum Environmental Flow Modeling (Adjusted Base Water Rules scenario 2008)

Dam water releases maintain hourly minimum flow requirements, which would be met by the addition of turbine flow and spill. For Adjusted Water rules year 2008, turbine flow is illustrated by **Figure A-6**, spill flow is illustrated by **Figure A-7**, and **Figure A-8** illustrates minimum flow. The OASIS model calculates daily electricity generation corresponding to turbine flow and is illustrated in **Figure A-9**. If spill water release is not sufficient to maintain minimum flow, turbine flow meets hourly environmental flow requirements. Dam hydropower generation corresponding to hourly minimum related-turbine flow, illustrated in **Figure A-10**, has no flexibility to dispatch for grid requirements. The balanced daily hydropower generation, illustrated in **Figure A-11**, has the flexibility to dispatch for grid requirements. During the spring, most plants meet their minimum release requirements fully by spill release (**Figure A-8**, **Figure A-10**). Then, daily turbine flow volumes have the flexibility to meet power grid requirements (**Figure A-9**, **Figure A-11**).

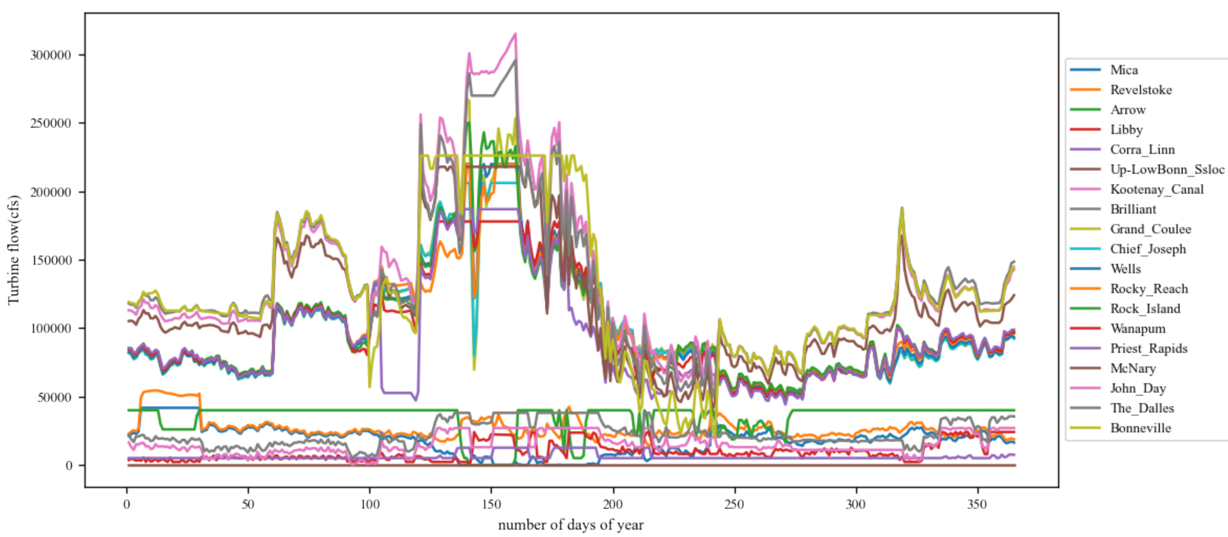

Figure A-6. Turbine Flow Data from OASIS Outputs Adjusted Water Rules 2008

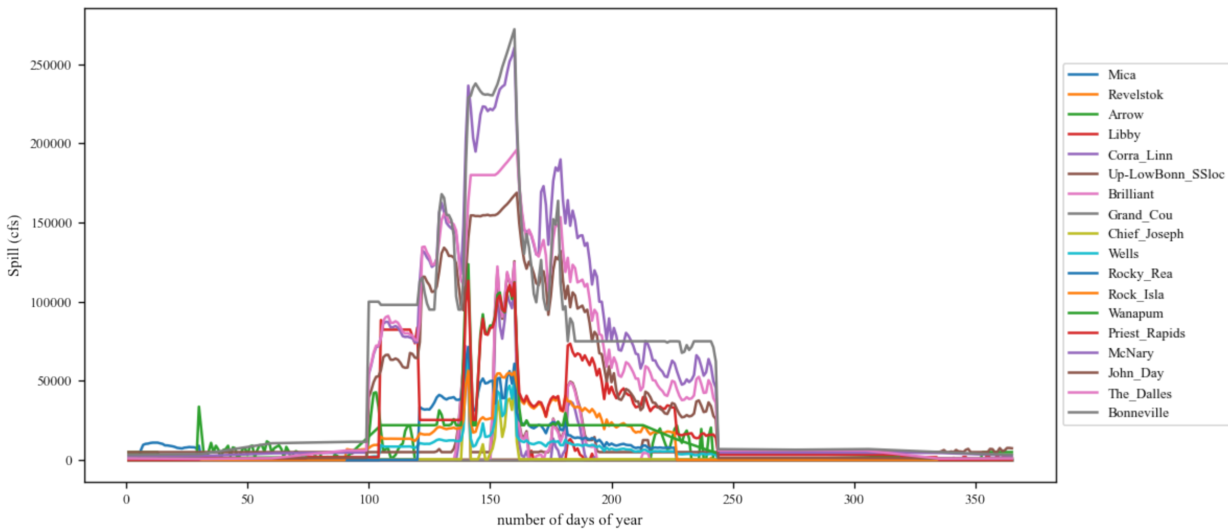

Figure A-7. Spill Flow Data from OASIS Outputs Adjusted Water Rules 2008

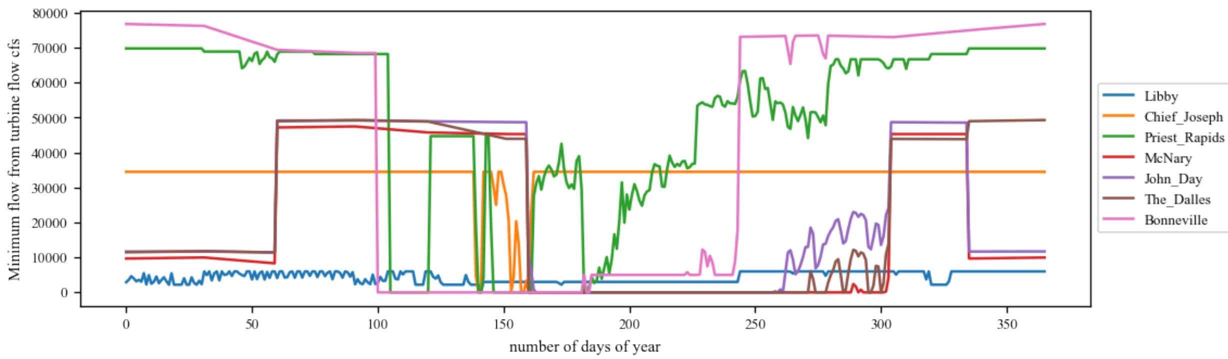

Figure A-8. Minimum Flow Requirement from Turbine Flow Adjusted Water Rules 2008

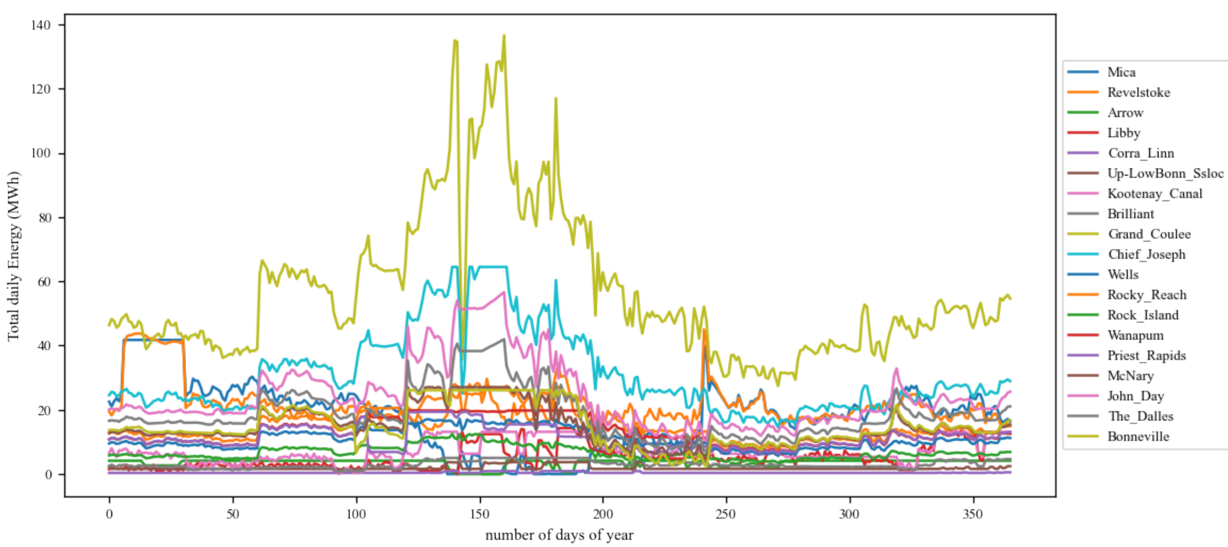

Figure A-9. Total Daily Generation from OASIS Output Adjusted Water Rules 2008

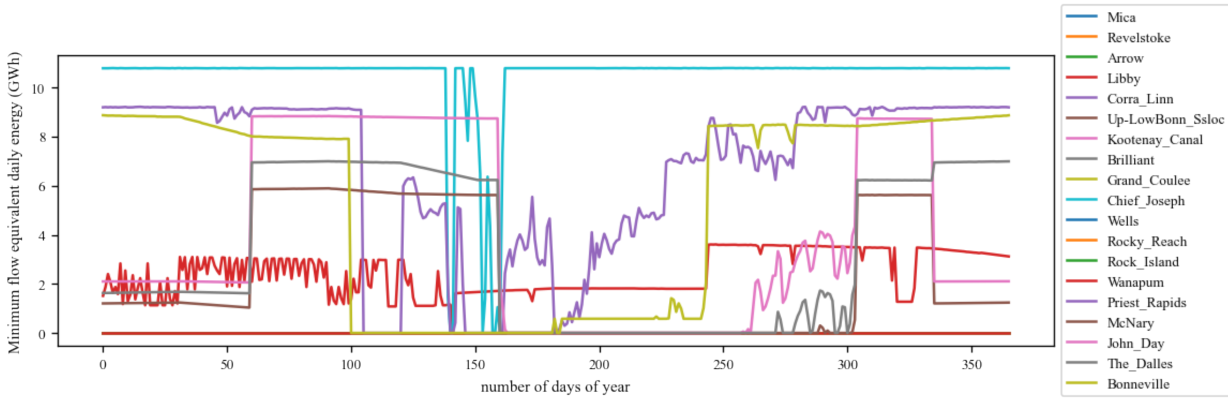

Figure A-10. Minimum Flow Equivalent Daily Fixed Generation (Addition of Hourly Generation)

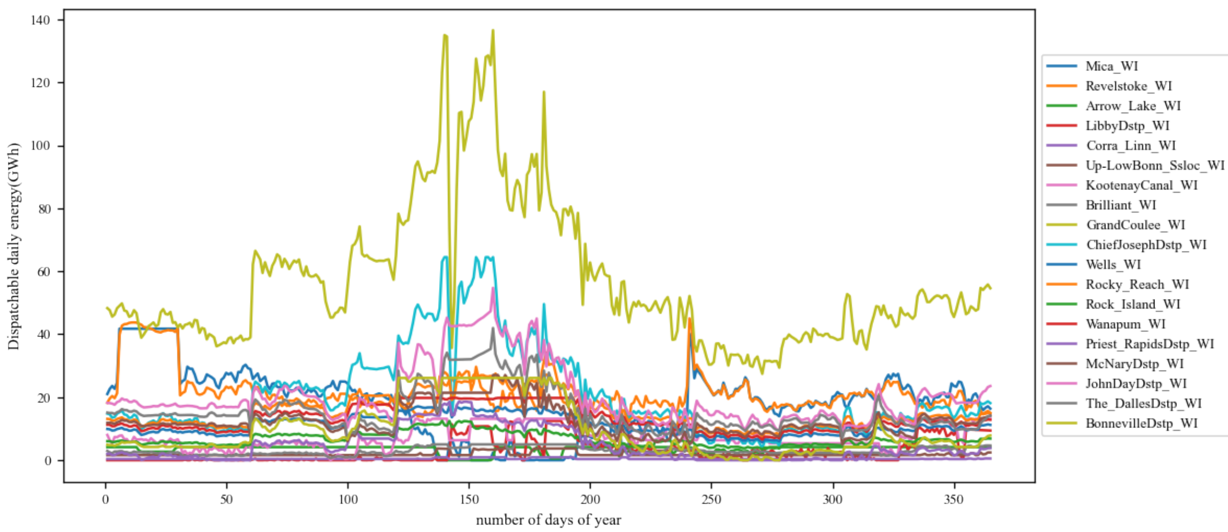

Figure A-11. Dispatchable Daily total Generation

Daily Hydropower Dispatch

Figure A 12, **Figure A 13**, **Figure A 14**, **Figure A 15**, **Figure A 16**, and **Figure A 17** illustrate seasonal average diurnal hydropower dispatch patterns for CRB hydropower plants. Similar to system operators, production cost models dispatch flexible hydropower plants at maximum capacity during peak periods and at minimum capacity during off-peak periods. Spring season's spill releases maintain minimum flow requirement, and turbine flow has the flexibility to release according to grid requirements. Therefore, spring generation spans a wider range between the maximum and minimum operation capacity of the power plants. The study team assumed that the technical minimum operation capacities of hydropower plants are zero. Since the model already accounts for the minimum flow requirement, the minimum operating capacities only depend on the technical parameters of the plants. In early summer, spill releases meet minimum release requirements. Later in the summer, turbine flows partly meet minimum flow requirements. Hence, on average, minimum operating capacities are greater than zero. In the winter and fall, minimum release requirements are met by both spill and turbine flows. Hence, hydropower generation flexibility is lower, and there is a smaller operating capacity range.

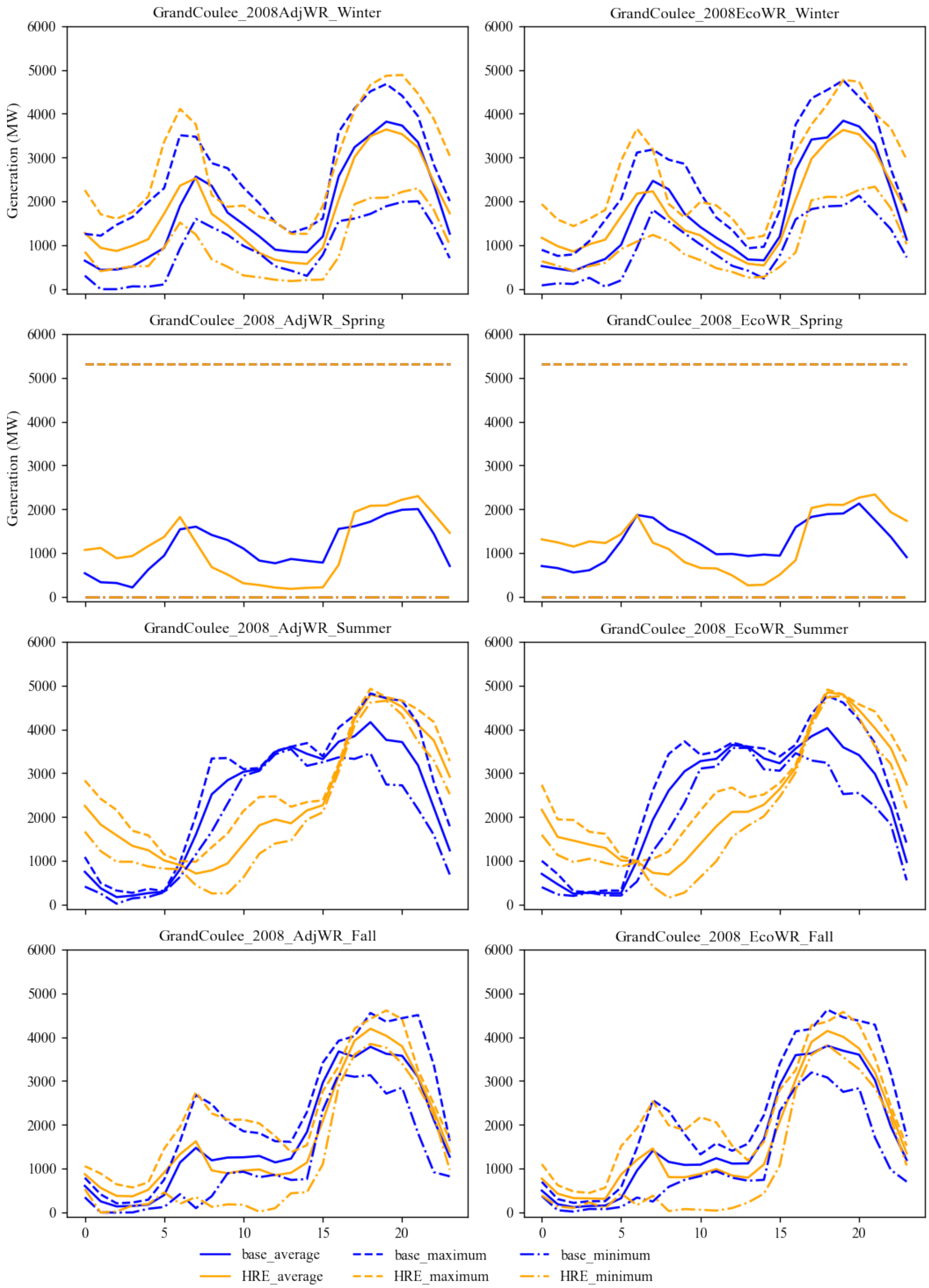

Figure A-12 Year 2008 Seasonal Average Diurnal Hydropower Dispatch Patterns of Grand Coulee Plant

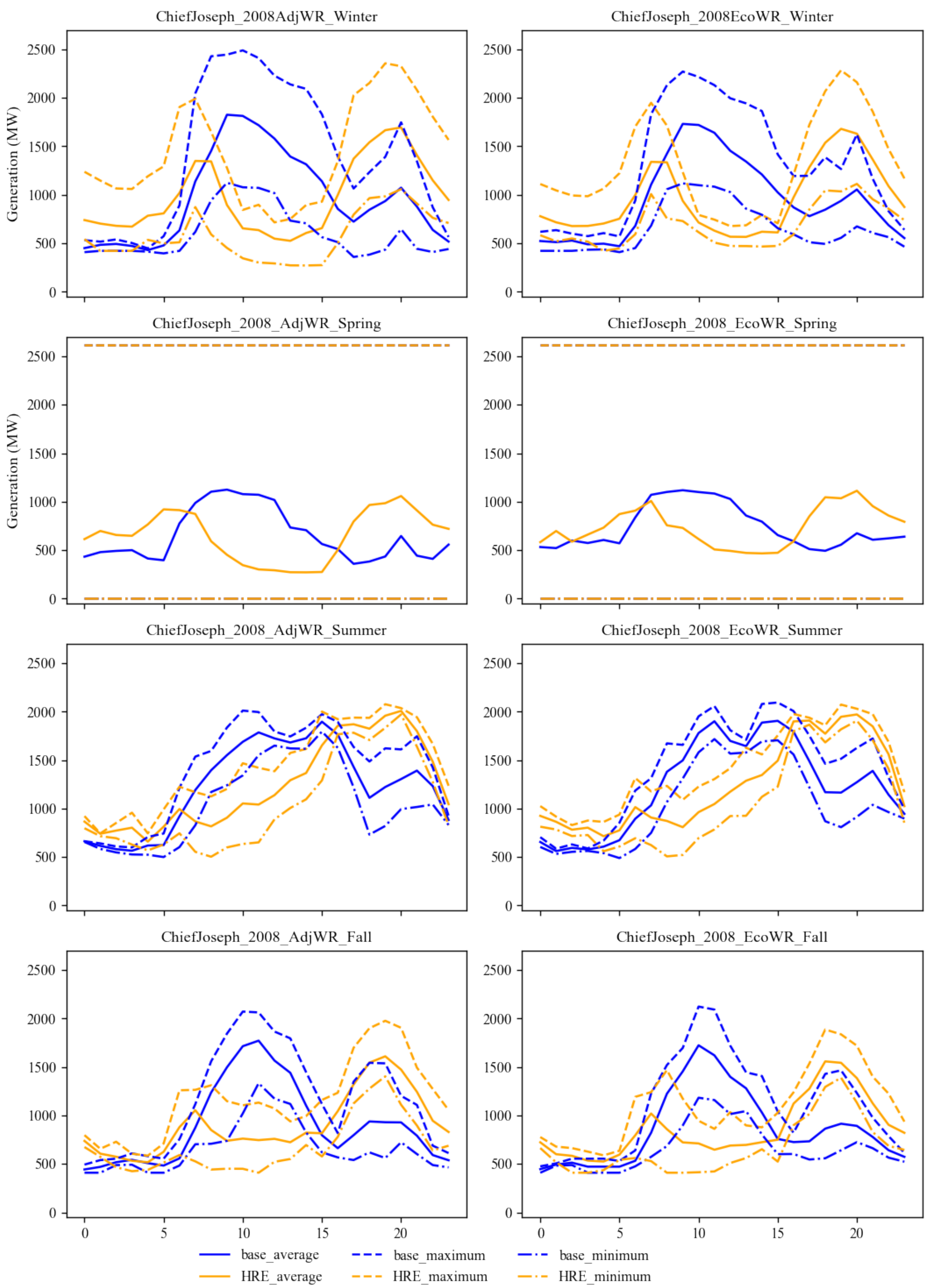

Figure A-13 Year 2008 Seasonal Average Diurnal Hydropower Dispatch Patterns of Chief Joseph Plant

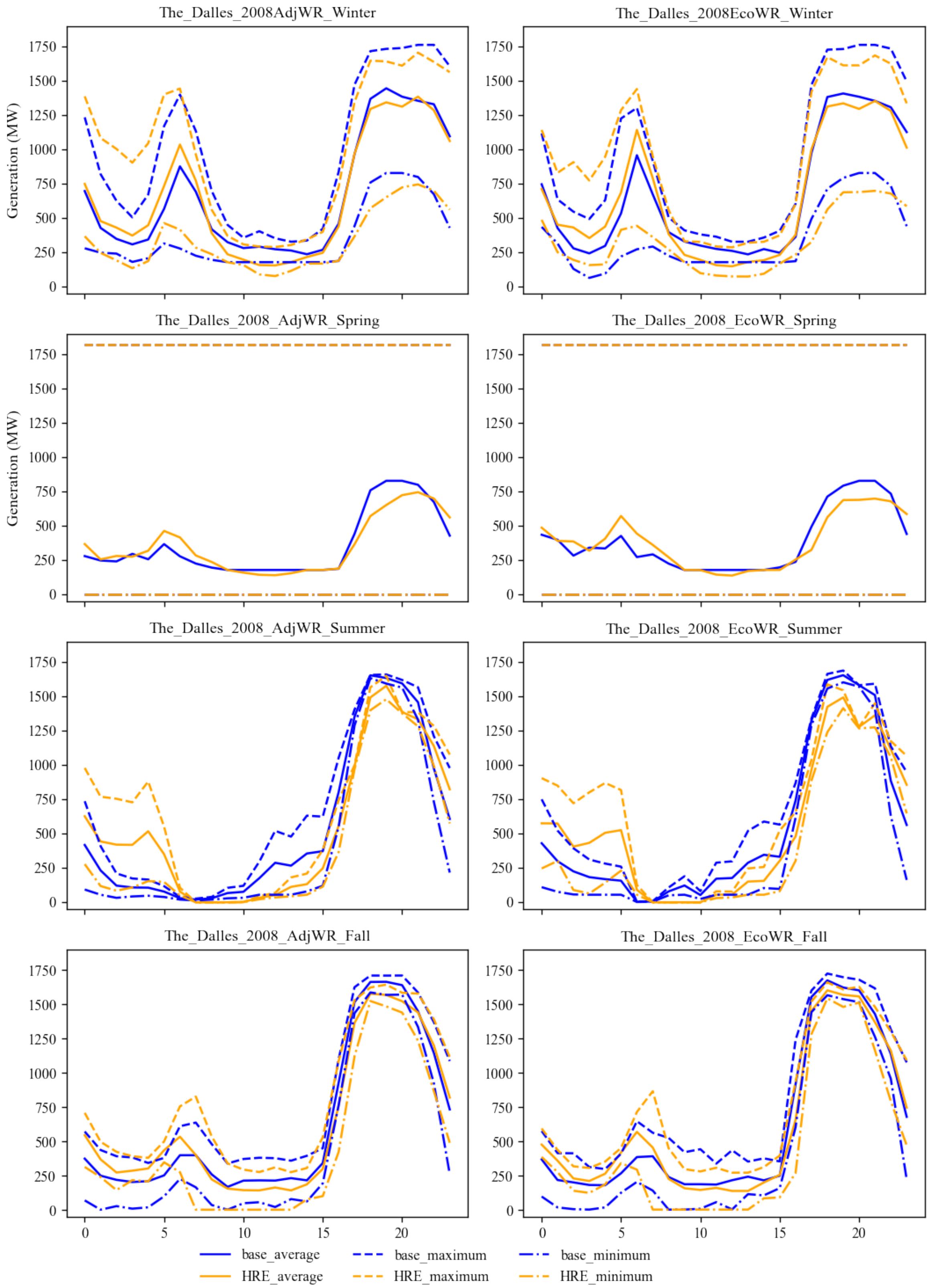

Figure A-14 Year 2008 Seasonal Average Diurnal Hydropower Dispatch Patterns of Dalles Plant

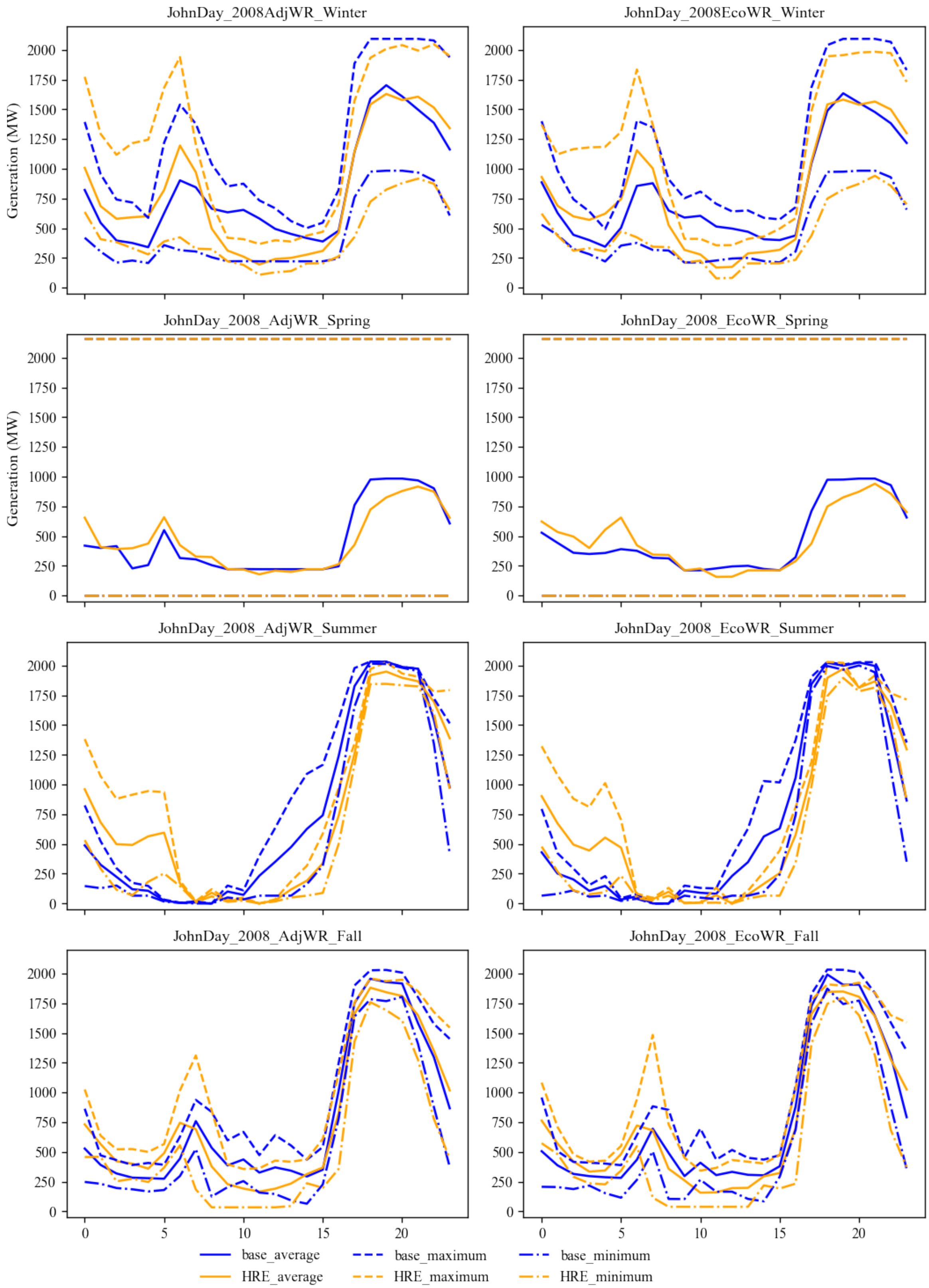

Figure A-15 Year 2008 Seasonal Average Diurnal Hydropower Dispatch Patterns of John Day Plant

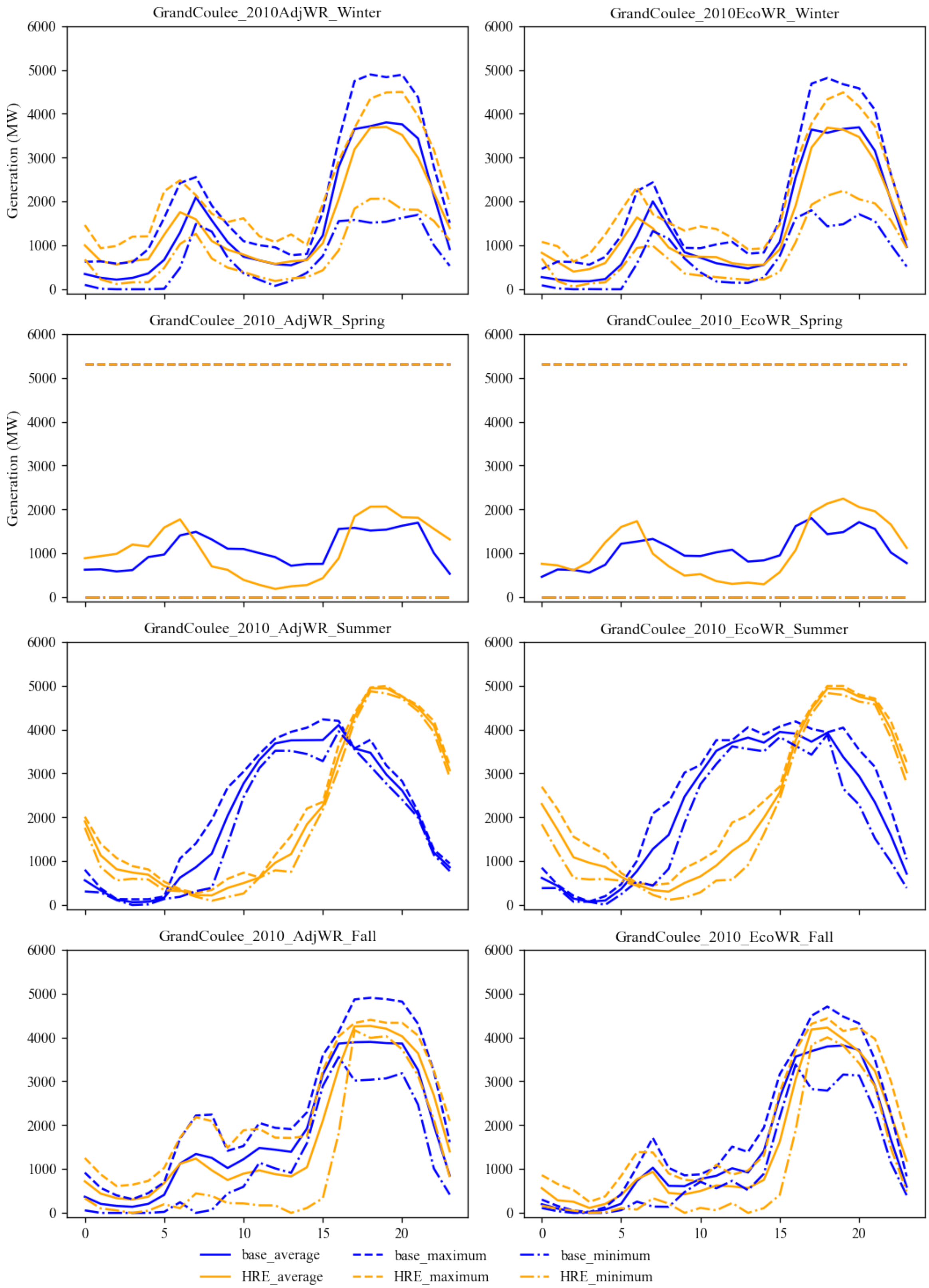

Figure A-16 Year 2010 Seasonal Average Diurnal Hydropower Dispatch Patterns of Grand Coulee Plant

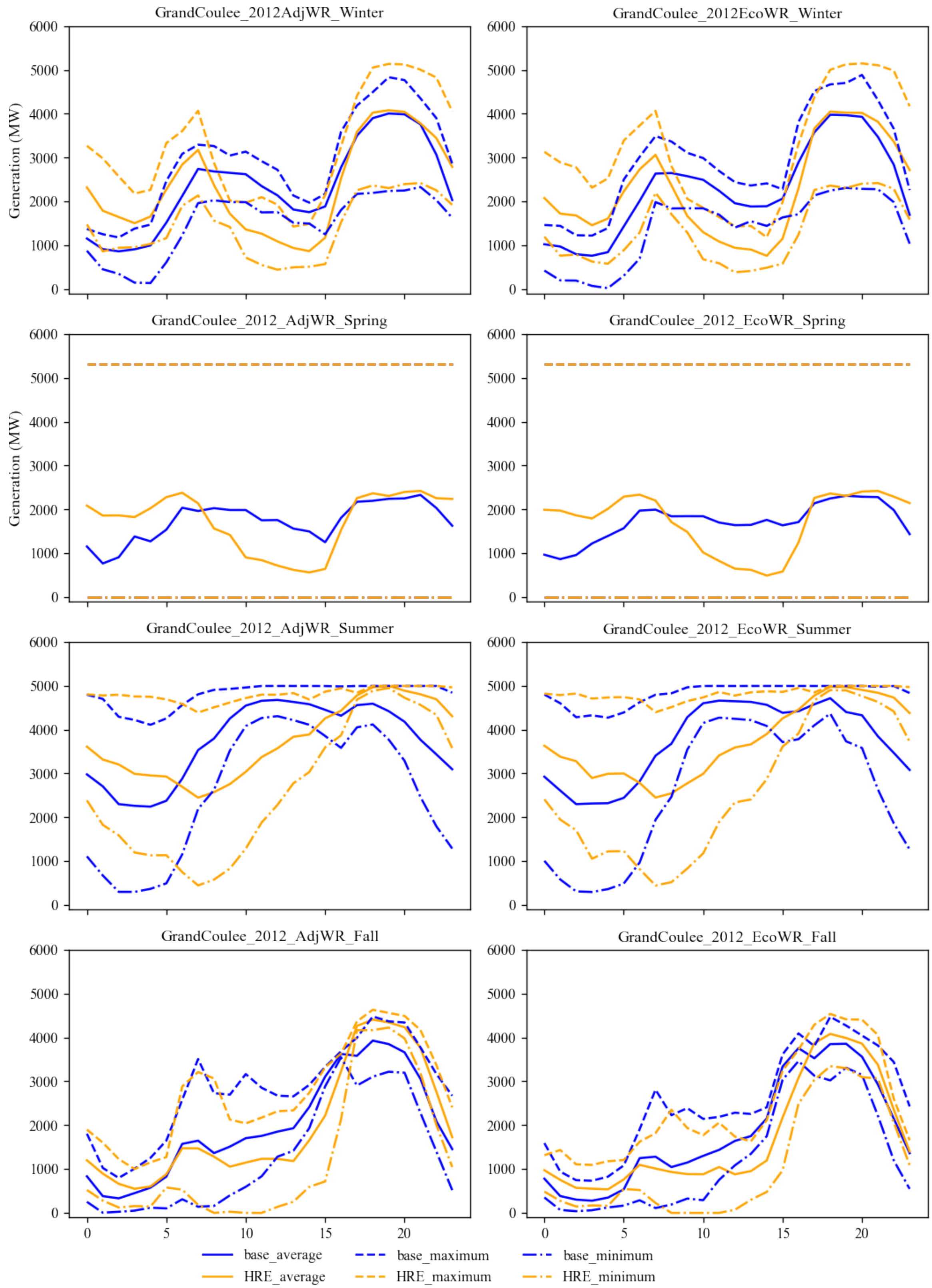

Figure A-17 Year 2012 Seasonal Average Diurnal Hydropower Dispatch Patterns of Grand Coulee Plant

A.1 Wind and Solar Energy Curtailment Across Scenarios

The study team compared wind and solar energy curtailment in the focus region for the base and high renewable energy grid scenarios (**Figure A 18**, **Figure A 19**, **Figure A 20**, **Figure A 21**, **Figure A 22**, **Figure A 23**). Curtailment values are high for high hydropower generation years such as 2011. There were no significant differences in VRE curtailment values across different water rule scenarios.

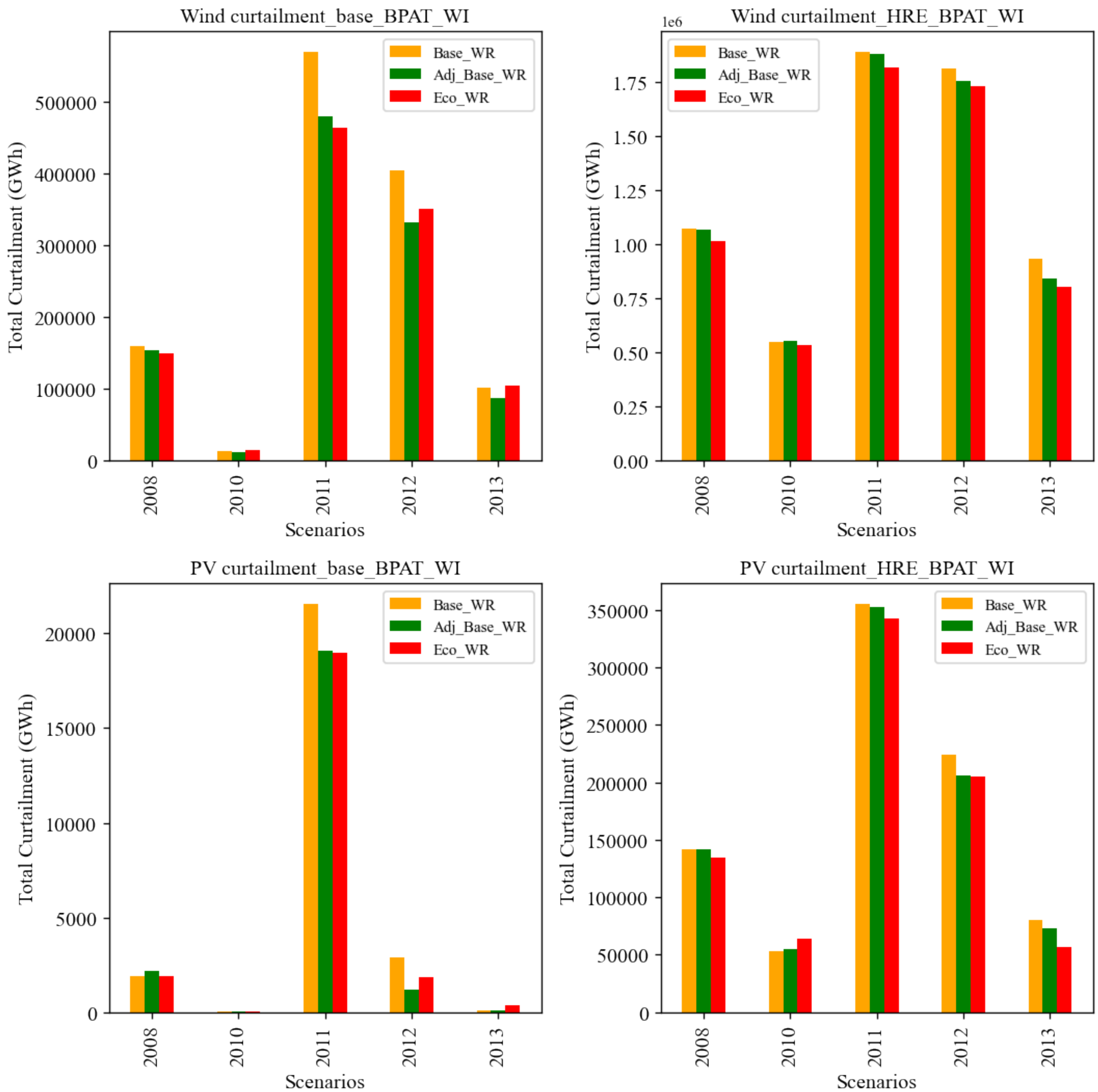

Figure A-18 BPA Wind and Solar Power Curtailment for Various Water, Grid, and Weather Scenarios for Base Water Rules, Adjusted Base Water Rules and Ecosystem Water Rules

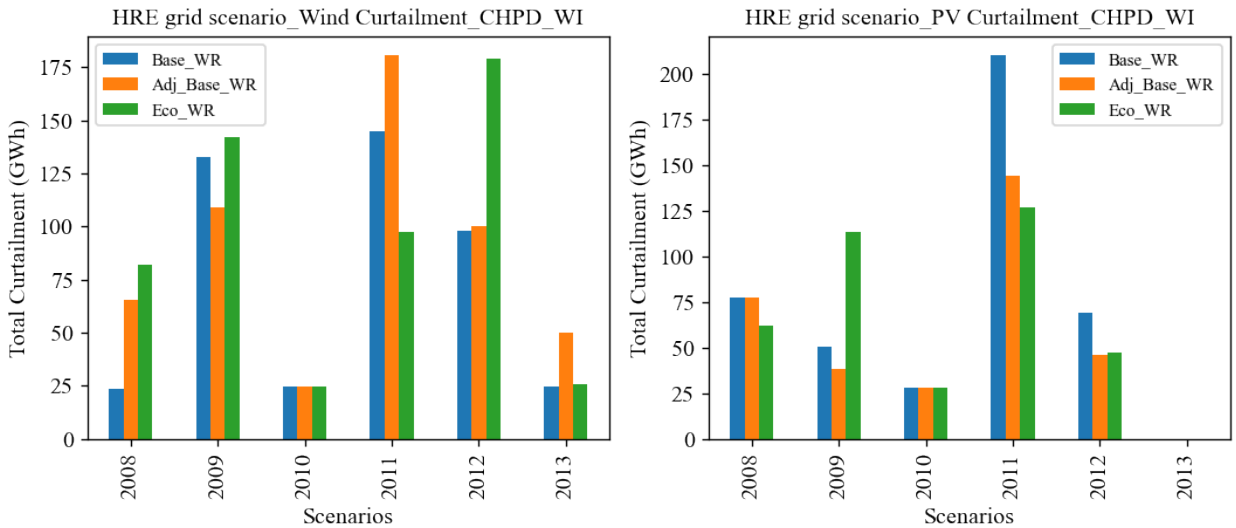

Figure A-19 Chelan County PUD Wind and Solar Power Curtailment for High Renewable Grid Scenario, and Water Rules and Weather Scenarios

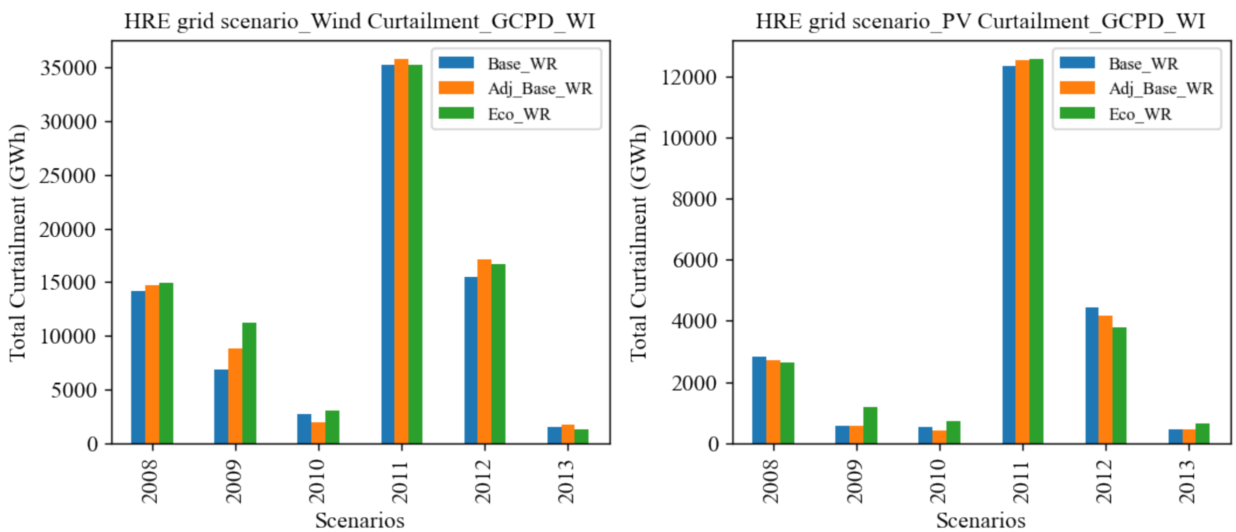

Figure A-20 Grant County PUD Wind and Solar Power Curtailment for High Renewable Grid Scenario, and Water Rules and Weather Scenarios

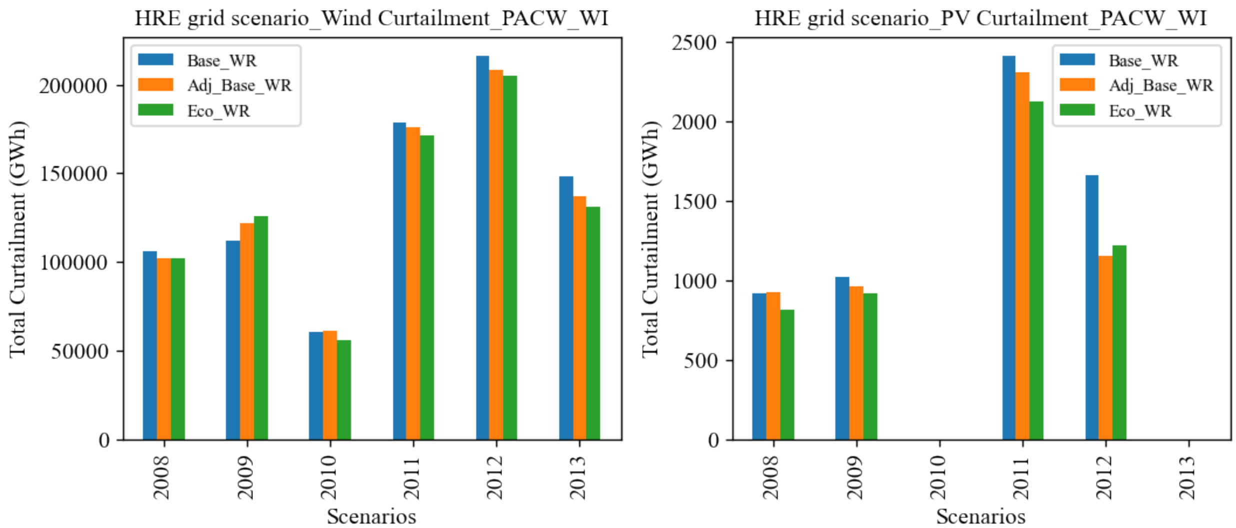

Figure A-21 Pacific Corp West Wind and Solar Power Curtailment for High Renewable Grid Scenario, and Water Rules and Weather Scenarios

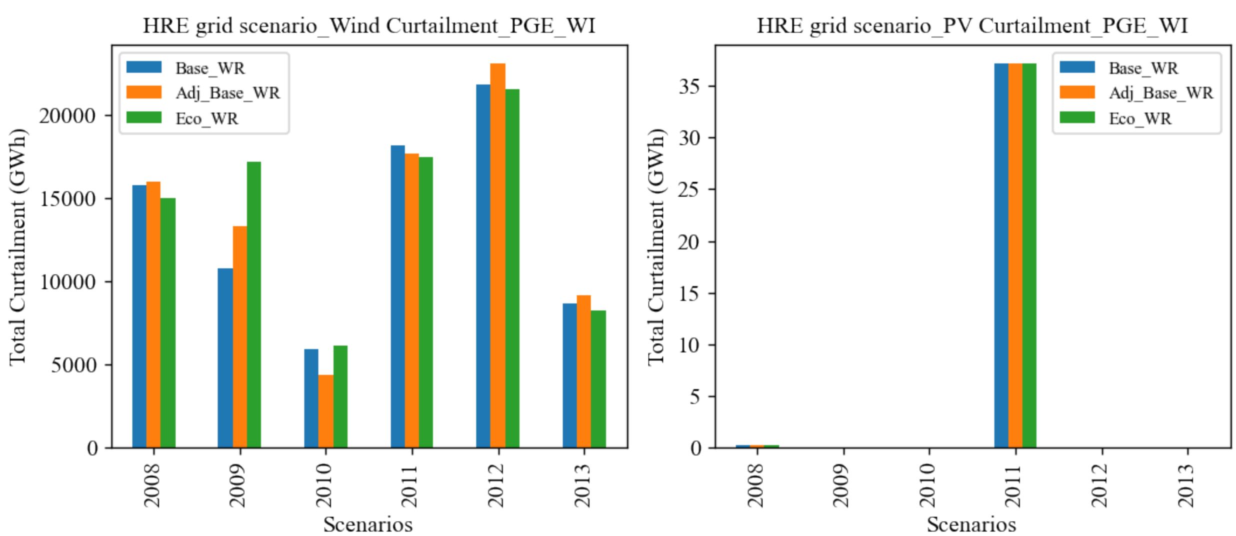

Figure A-22 Portland General Electric Company Wind and Solar Power Curtailment for High Renewable Grid Scenario, and Water Rules and Weather Scenarios

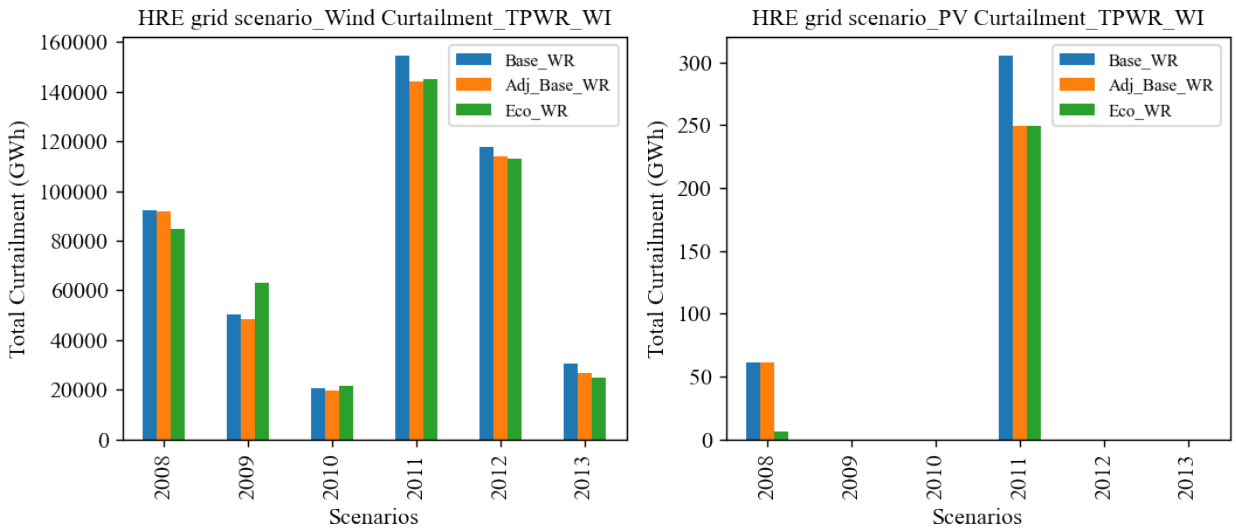

Figure A-23 City of Tacoma, department of Public Utilities Wind and Solar Power Curtailment for High Renewable Grid Scenario, and Water Rules and Weather Scenarios

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