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Optimizing Hydropower Operations While Sustaining Ecosystem Functions in a Changing Climate

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation and bring ideas from the lab to the marketplace. The CEC and the state's three largest investor-owned utilities—Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company—were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Optimizing Hydropower Operations While Sustaining Ecosystem Functions in a Changing Climate is the final report for Contract Number: 300-15-004 conducted by the University of California, Merced. The information from this project contributes to the Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the CEC at ERDD@energy.ca.gov.

ABSTRACT

California's long-term energy plans depend on a science-based understanding of the impact of climate change on renewable energy systems, especially hydropower resources and urban, agricultural, environmental, and recreational water users. Climate change is expected to exacerbate the state's already high hydroclimatic variability, creating new challenges for management of hydropower and ecosystems, including increased uncertainty and potential increased frequency of system failure. Water system simulation models can help understand and overcome these challenges through climate impact and management scenario analyses.

This Project developed CenSierraPywr, a hydropower optimization modeling framework to consider institutional and physical constraints placed on hydropower operations. This framework – which integrates models, modules, routines, algorithms, wholesale electricity prices and data – has the capability of running various climate change scenarios. The model focused on four major San Joaquin River subbasins: Stanislaus, Tuolumne, Merced, and Upper San Joaquin. Ten climate models at two projected intensities for greenhouse gas emissions were used to generate hydrological conditions that assessed potential impacts on system operations and behavior under future conditions (2031-2060). In addition to global circulation model-centric analyses, the CenSierraPywr model investigated more ecologically supportive flow releases ("functional flows") from the basin outlets. Although alternative flow management for environmental objectives does not have a large impact on hydropower, there may be tradeoffs with water supply and timing. The scenarios provide insights into management-relevant decision making and trade-offs with hydropower generation in the study area.

Keywords: Hydropower, climate change, general circulation models, water resources management, water allocation, instream flow requirements, optimization, system analysis, scenario analysis, *Pywr*, functional flows

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EXECUTIVE SUMMARY

Introduction

California has the second largest hydropower production capacity in the United States and is one of the top three hydropower producing states. Hydropower generation accounts for 7 percent to 20 percent of the annual energy production in the state. Hydropower generation relies on water availability from precipitation and California has high variability in precipitation.

Climate change is expected to increase hydroclimatic variability and challenge hydropower production. Since hydropower is critical for the state's long-term energy development, future energy development plans must have a science-based understanding of the potential impact of climate change on hydropower facilities.

Since reservoir and hydropower facilities operate under a variety of constraints, water system simulation models that use *realistic* assessments of actual facility operations with climate change impacts can help decision-makers and hydropower operators understand and overcome these challenges.

Project Purpose

Over the decades, the hydropower systems of California have been extensively studied for different water resource interests with various optimization models developed for these investigations. These models have limitations related to size or lack of incorporating actual operating conditions. The models tend to focus on a single facility or are run using monthly data and do not include daily operating constraints. Developing a *realistic* model would include actual operational decisions and constraints in the model framework. Such realistic optimization models offer a platform for testing a range of scenarios and provide regional water resource planners and reservoir operators with a decision-support tool to assess their facilities operations in an integrated way.

The team from the University of California, Merced developed a *realistic* hydropower optimization model, CenSierraPywr, to understand the impact of climate change on California's large- and medium-sized hydropower facilities. This framework integrates models, modules, routines, algorithms, real market pricing and data as well as the capability of running various climate change scenarios using multiple greenhouse gas emission scenarios.

Project Approach

The team's modeling efforts with CenSierraPywr was built on previous studies that incorporated rainfall-water runoff under various climatic warming scenarios. The scenarios concentrated on the four major contributing basins to the San Joaquin River watershed in the central west slope Sierra Nevada – Stanislaus, Tuolumne, Merced, and Upper San Joaquin – since they provide water for major hydropower systems, urban demand in the San Francisco Bay Area, and agricultural demand in the Central Valley and they are seen as vital to restoring ecological conditions in the Sacramento-San Joaquin Delta.

The San Joaquin River basins operations were assessed using 10 general circulation models (GCMs) (a type of climate model using the planet or ocean atmosphere). Four core GCMs were focused on with their corresponding end-of-century comparative outcomes: Warm/Dry, Cool/Wet, Middle, and Complement/Cover. Although the study focused on four core GCMs, six additional GCMs were added to explore the breadth of potential outcomes relevant to hydropower generation.

The research was informed by a technical advisory committee and experienced water resource researchers. The committee included representatives from the Merced Irrigation District, Southern California Edison, United States Department of Energy, San Francisco Public Utilities Commission, United States Department of Agriculture Forest Service, and the University of California, Davis. Input from the advisory committee and other domain experts ensured that CenSierraPywr was populated with accurate, timely data.

The project team undertook a comprehensive review of Federal Energy Regulatory Commission (FERC) licenses and other local guidelines to understand the legal and operational constraints for the facilities. Rim dams and reservoirs — low elevation, large multi-purpose installations — along with their flood control and water diversion operations were incorporated in CenSierraPywr. Optimization efforts focused on basins operated for hydropower production, maximizing revenue and production decisions with energy pricing derived from an independent energy model prediction output.

At each stage of the CenSierraPywr model development, consultations with the advisory committee and other stakeholders refined and validated model behavior.

Project Results

The team's analysis of the climate change scenarios showed that the water inflow to the rim dam reservoirs increased in winter and decreased in summer. They found that in the future there will be more dry and wet years than normal years, reinforcing a bimodal distribution (two different types) identified by others (Null and Viers 2013).

This forecast indicates a shift in precipitation patterns and the impacts of a warming climate. The forecast indicates higher variability in wet months and lesser variability in dry months. Hydropower production increases in fall, winter, and spring but is largely diminished in summer.

The decrease in summer generation is less because of the regulating effect of reservoirs but more due to a shift in hydroclimatic signals. Reservoir storage and operations moderated the impacts of climate warming shifts in hydrological response, particularly in hydropower-optimized basins (Stanislaus and Upper San Joaquin); however, the amount of storage, as well as basin operational objectives, mediated the outcomes of future climate change signals. Disruptions to outflows were less substantial than might be expected annually or seasonally due to the flexibility afforded by reservoir storage. When outflows were below historical norms, however, the wide range of possible future outcomes also indicated a much lower outflow from all modeled basins.

The CenSierraPywr model framework proved to be a flexible platform for investigating numerous questions related to climatic and management constraints on the study area. The greatest limitation was reconciliation between the observed data and the infrastructure operations to ensure the time and locations of the CenSierraPywr model matched on-the-ground operations. Other models that operate at a weekly or monthly time step provide more generalized results, whereas the CenSierraPywr model required more calibrated data which was not always available or complete. As model refinement occurs through coordination and engagement with utilities and other domain experts, assumptions and sources of error will be reduced.

Knowledge Transfer

The CenSierraPywr effort has resulted in an open-source modeling framework and optimization method intended to support users understanding of the impacts of climate change and a changing energy configuration on hydrogeneration facilities, individually or in series. Modeling outcomes have been communicated with public and professional circles as well as regional utilities and water resource managers. Open-source repositories, such as GitHub, have provided an accessible space for storing and distributing the model whereas targeted professional publications and meetings will be used to spread knowledge of the model. The CenSierraPywr effort has required and will continue to greatly benefit from operators' and utilities' feedback within the study area.

Benefits to California

The CenSierraPywr effort has provided a better understanding of the impact of climate change in relation to changing energy configuration in the central Sierra Nevada. The flexible framework will continue to support the state in the development and visioning of long-term operation planning. As FERC licenses are updated periodically and state expectations for flow management evolve, hydropower will face the challenge of balancing production with other water users. This study offers insights into these potential future flow management trade-offs as well as a framework which can accommodate alternative management and climate scenarios. CenSierraPywr results lay the groundwork for finer analysis of facility resilience and the development of multi-basin modeling for the study area and beyond.

Additionally, the modeling methods contribute to the science of water systems management and will support future work both in California and beyond. Improvements to these investigations benefit ratepayers over time as the body of work strengthens water management, particularly as competing needs for water are heightened due to climate change.

CHAPTER 1: Introduction

Background

California is the second largest consumer of energy in the United States (U.S. Energy Information Administration 2018). In 2018, more than 50 percent of the state's energy came from renewable sources including conventional hydropower[1] . Among the states, California has the second largest hydropower production capacity and is one of the top three hydropower producing states.[2] California's hydropower relies on water availability, and the Mediterranean climate of cold wet winters with a snowpack and hot dry summers causes the state to be highly dependent on snowpack for its hydropower production during most of the year. The existing water infrastructure in the state is geared towards managing current precipitation patterns of winter snowfall and snowpack cycles with gradual spring snow melt (Nover et al. 2019).

California exhibits the highest variability in its precipitation among all the states in the country (Dettinger et al. 2011). Annual precipitation in the state ranges from 50 percent to 200 percent of average values (Lund 2016). The large inter- and intra-year variation impacts water availability for hydropower facilities. Although the network of reservoirs in the state has been helpful in mitigating the impacts of precipitation variability (Lund 2016), extended droughts (as experienced in 2011-2015) strain these systems by decreasing hydropower production through changes in magnitude and timing of water availability for energy generation. Depending upon the climatic conditions, the annual contribution of hydropower can range from 7 percent to 20 percent of the total energy production in the state[3] and climate change is expected to further increase the variability and challenge to hydropower production. Warming temperatures due to climate change are expected to increase winter rainfall and reduce snowpack, which will change the hydrological cycle in the state. These impacts have significant considerations given California's energy and environmental goals in which hydropower production is expected to play an increasingly important role. The state has a plan to provide 50 percent of retail electricity from renewable sources by 2030, increase distributed power generation, and have 100 percent zero-carbon electricity by 2045.[4] The future grid configuration will require "flexible" electricity sources that can cater to sudden changes in demands. Hydropower is not only a zero-carbon, but is also a flexible energy source. It is critical for the state's long-term development and future energy plans to have a science-based understanding of climate change's impacts on hydropower facilities.

[1] California Energy Commission (2018) 2018 Total System Electric Generation.

[2] US Energy Information Administration (2020)

[3] In 2015, due to extended drought, hydropower contributed to only 7% (13,808 GWh) of the state's net electricity generation, whereas in 2017 (after above-normal rains), it contributed to about 20% (42,363 GWh). (CCCA4 Key Findings)

[4] CA SB100 | 2017-2018 | Regular Session. (2018, September 10). LegiScan.

Previous studies have looked at reservoir operations and hydropower production in response to climate change. The studies range from state-wide analysis to single reservoir operations. Optimization models have been developed to manage reservoirs to either maximize returns from hydropower production, to minimize costs, or to explore potential ways to maintain environmentally friendly operations (Craig et al. 2019; Goharian et al. 2017; Rheinheimer, Yarnell, and Viers 2013; Madani and Lund 2009). However, optimization models sometimes suggest outcomes that are not politically or legally feasible and hence are unapplicable. Although such studies provide critical understanding of the systems and help identify optimal resource usage within ideal conditions, they are difficult to implement, and remain an academic exercise.

Reservoir and hydropower facilities operate under a variety of constraints. The non-federal hydropower facilities are regulated by the Federal Energy Regulatory Commission (FERC) (Federal Energy Regulatory Commission 2017), and must obtain a license from FERC to operate. The licenses are typically given for 30 to 50 years and may contain provisions for maintaining minimum flows and ramping rates downstream of reservoirs. Low-elevation dams (rim dams) are operated in accordance with U.S. Army Corps of Engineers (USACE) flood control manuals to prevent flood related damage in downstream regions. Additionally, there may be contracts and agreements to provide water downstream for human consumption or habitat restoration, that need to be honored. Incorporating on-the-ground operating conditions into modeling systems is necessary for realistic scenarios. Such models will find more traction with stakeholders who are involved with operation and planning.

Existing Simulation and Optimization Modeling

Over the decades, the hydropower systems of California have been extensively studied for different water resource interests with various optimization models. Since the publication of the first *Climate Change Assessment Report* in 2006, there have been major studies related to the impact of climate change on water and energy systems in California, particularly in relation to hydropower production.

There are two statewide system models that are widely used in California to better understand water allocation:

- **CalSim** (including its successors CalSim 2 and CalSim 3) is a systemwide model used by the California Department of Water Resources (CDWR) and developed jointly with the U.S. Bureau of Reclamation. It uses a mixed integer linear programming solver to allocate water across the network (Draper et al. 2004). It was primarily developed for management of the State Water Project and the federal Central Valley Project. Recently the model was modified (to CalSim2 or CalSim-II) to study the impact of climate change on managed flows in the Sacramento/San Joaquin River basins (Noah Knowles and Cronkite‐Ratcliff 2018). CalSim 2[5] is a water management optimization model that uses inputs such as inflows to the reservoirs and reservoir management decisions to produce managed flows at a monthly timestep. Although, it uses linear programing, it is not an optimization model. It simulates allocation of water at basin level for various policy and infrastructure related interventions. CalSim 2 contains some significant

[5] CalSim 3, which is currently under development, will improve the spatial resolution and have better representation for groundwater and water supply and demand estimations.

limitations in expanding its application. First, CalSim 2 considers the future water demand as static. Second, CalSim 2 uses perturbation ratios on historical hydrological monthly time series to represent changes in hydrology due to climate change. This limits studies from developing more robust intra-annual or intra-decadal scenarios, where the patterns may not be represented by historical data (Wang, Yin, and Chung 2008; Knowles and Cronkite‐Ratcliff 2018). Finally, CalSim 2 is not specifically developed to study the hydropower facilities in the state.

- **California Value Integrated Network (CALVIN)** was developed by researchers at University of California (UC), Davis as a deterministic economic-engineering optimization model for major water systems (including groundwater resources and water reuse) across the state of California (Draper et al. 2003). CALVIN used a generalized network flow optimization solver, which allows for gains and losses to represent return flows and system losses at monthly temporal timesteps to maximize economic value of water use for agriculture and urban sectors within physical and institutional constraints. CALVIN was later modified to be more versatile, cross-platform and compatible with other linear programing solvers (Dogan et al. 2018). It has been used for studying water supply vulnerability and adaptation strategies for various climate change driven scenarios for California's 4th Climate Change Assessment (CCCA4) (Herman et al. 2018). While the original model was developed to run with perfect foresight of water availability for the full time series, the climate change study considered a limited (annual) foresight, thus representing a more realistic operational scenario.

Although CALVIN has been used successfully to explore various water management options, it does not consider hydropower production and flood control functions explicitly. CALVN models rim dams only. The monthly temporal resolution of such models also does not include detailed environmental flow requirements. In addition to CalSim 2 and CALVIN, many smaller scale optimizations have been developed to study hydropower systems in California. Craig et al. (2019) developed a "net-revenue-maximizing optimization model" to study the tradeoff between revenue generation from 36 potential small hydropower facilities and in-stream flow requirements in the Yuba basin. The non-linear relationship of hydropower generation with discharge and varying head were accounted for by using piecewise linear approximation functions. The environmental flows requirement was considered as a minimum flow or as a percentage of natural flows. The Craig et al. (2019) study used energy and ancillary service prices from the California Independent System Operator (CAISO) northern zone and was run at a sub-daily timestep. Dogan and Lund (2018) used a combination of Linear Programming (LP) and Nonlinear Programming (NLP) optimization models to study the effect of increased solar production in California on hydropower production. This effort used a python-based optimization model (*Pyomo*) to develop a routine that first used LP with a simplified objective function and then used the first pass outputs as the initial parameters to solve a more complex iteration with NLP.

Madani and Lund (2009) developed a hydropower optimization model for the high-elevation (> 1,000 ft) hydropower facilities based on energy conservation and balance. In the **Energy-Based Hydropower Optimization Model (EBHOM)**, the changes in reservoir storage are represented by "Energy Storage Capacity" and the objective function to maximize revenue generated by energy production. EBHOM ran at a monthly timestep and used fixed monthly energy prices. To incorporate hourly energy price fluctuation, the authors suggested a nonlinear approach to represent price variability. EBHOM was applied to 137 high-elevation hydropower facilities using Microsoft Excel based "What's Best" solver. The EBHOM model does not consider seasonal variability or environmental flow requirements. The authors also applied this model for studying impact of climate change on high elevation hydropower energy production capability (Madani and Lund 2010).

Other recent hydropower optimization efforts include hybrid multi-objective optimization of Folsom reservoir operation to maximize storage in the watershed, while also maximizing hydropower production (Goharian et al. 2017); developing an Evolutionary Algorithm based reservoir operation optimization model for Oroville–Thermalito Complex (Yang et al. 2015); and linear, multi-reservoir optimization model for hydropower system in upper Yuba River watershed to assess the cost of climate change and environmental flow regulations (Rheinheimer, Yarnell, and Viers 2013).

Rheinheimer et al. (2014) used the Water Evaluation and Planning system (WEAP; Yates et al. 2005) to develop the **Sierra Integrated Environmental and Regulated River Assessment (SIERRA) model.** SIERRA simulated major reservoirs and hydropower facilities in 13 of 15 basins in the upper western slope of the Sierra Nevada with the goal of assessing spatial trends in impact of climate change on hydropower production. Notably, SIERRA did not use optimization, but instead used statistical regression to simulate operations. The authors considered three warming future climate change scenarios (2, 4 and 6°C temperature increases). The study showed that in general, due to a 6°C increase in temperature, hydropower would decrease production by 8 percent for the whole region, although production would increase during winter months (January to March) due to higher rainfall incidents and decrease in other seasons. Spatially, the SIERRA model showed a consistent decrease in hydropower generation in northern basins under different warming conditions. The central Sierra Nevada basins showed higher resilience to changes in climate, while southern regions showed mixed outcomes. The central region, in fact showed a slight increase in hydropower production for lesser warming scenarios, as well as increased recreational opportunities (Ligare et al. 2012).

Existing Model Limitations

The optimization models developed for large systems typically focus only on large reservoirs and utilize coarse temporal resolution. They operate at monthly timesteps and are not adequate to handle daily or weekly variability required for environmental flow requirements. Additionally, energy prices fluctuate at an hourly timestep, hence revenue maximization optimization at a monthly timestep is too coarse a resolution to reflect such price fluctuation. The smaller scale models usually focus on a single or small set of hydropower facilities without integrating with the larger system.

Rheinheimer et al. (2014) used a simple statistical approach whereby historical hydropower releases were regressed against a regional water year type to simulate hydropower demand. Hydropower operations are driven at least partly by actual (net) energy demand and associated wholesale market electricity prices. In the 2014 study, climate change was represented by a uniform increase of temperature (without considering the change in precipitation) across the whole region. This ignores the spatiotemporal heterogeneity in climate change. They also did not consider longer term planning. The statistical approach used is not based on actual operational decisions and may not have captured trends that are excluded from the historical period considered for the study. Operators usually consider seasonal and/or annual hydrological and energy forecasts while planning their operations. The weekly spatial and temporal resolution of SIERRA does not always suffice to study issues that are relevant at finer temporal resolution, such as ecological flows. Since WEAP allocates water based on priorities, it is not an optimization model. SIERRA did not consider long-term planning when doing priority-driven daily water allocation. Finally, SIERRA did not consider the rim dams to have a better understanding of impact of climate change on floods.

Problem Statement

The CCCA4 suggests the temperature will increase between 3.1–4.9 °C (5.6–8.8 °F) and water supply from snowpack will decline by as much as two thirds by 2100. Studies also suggest changes in the timing and magnitude of hydrological flow in rivers in the region (Hidalgo et al. 2009, Das et al. 2013, Knowles et al. 2018). Despite these studies, FERC is reluctant to consider climate change within their licensing framework, due to their perceived lack of confidence on climate change studies (Viers 2011). This suggests a need to better quantify the impact of climate change on hydropower generation in the state. With much focus on the Sacramento-San Joaquin Delta (Delta), which is fed by 50 percent of the state's streamflow and is central to water allocation and conservation efforts, there is a need to examine statewide water system operations in an integrated way, with a multi-basin, water-energy-environment focused modeling framework. There is a need to look at hydropower production in an integrated way within the context of updated information on climate change and instream flow requirements.

Models built without existing operational constraints are of limited use for planning and policy making. Thus, there is a need for realistic assessments that bring together facility-specific operations, climate change impacts, and contemporary science of instream flow requirements. *Realistic* implies including actual operational decisions and constraints in the model framework. Such realistic optimization models could offer a platform for testing a range of scenarios and could provide a decision-support tool for regional water resource planners and reservoir operators to look at their facilities in an integrated way.

Project Scope

The objective of this project was to develop a realistic hydropower optimization model that considers institutional and physical constraints placed on hydropower operations. Institutional constrains include adherence to flood control rule curves and meeting minimal flow or obligatory downstream demand requirements and physical constraints are related to capacity of hydropower facilities and supporting infrastructure. The CenSierraPywr model has been developed with capability of running various climate change general circulation model (GCM) scenarios, which have been developed using multiple GHG emissions scenarios (Appendix C for more details on GCMs). This approach is intended to leverage the downscaled climate modeling work done for the CCCA4. CenSierraPywr is integrated with an energy model to forecast a more realistic future energy configuration. CenSierraPywr constraints and options were chosen in collaboration with energy and water stakeholders on the technical advisory committee (TAC). CenSierraPywr allows for tradeoff analysis between hydropower production and water demand/requirements downstream and with changing climate parameters.

Based on the results of Rheinheimer et al. (2014), this study was focused on the central Sierra Nevada range of California. The 2014 study suggested that hydropower production in the central Sierra Nevada region was more resilient to climate change. Unlike the northern and the southern region, the central region showed an increase in hydropower production due to operational changes as a function of snowmelt runoff time. This region is not only critical for the state's future energy security, but also a significant source of water for agriculture and urban activities. With the passage of the Sustainable Groundwater Management Act (SGMA), the water available from central water basins will be critical for groundwater management in the Central Valley as groundwater use is curtailed. The subbasins of the central Sierra Nevada also contribute significant water to the Sacramento-San Joaquin Delta via the San Joaquin River (SJR). Although, the contribution of the SJR to the Delta is much smaller than the Sacramento River, the SJR is more dammed and regulated.

The information and basin delineation used in the SIERRA WEAP model (Rheinheimer et al. 2014) was used as a starting point for this modeling activity. Some of the basic information, such as catchment boundaries, reservoir and hydropower characteristics as well as location of USGS gauges were directly used from the SIERRA model in this study.

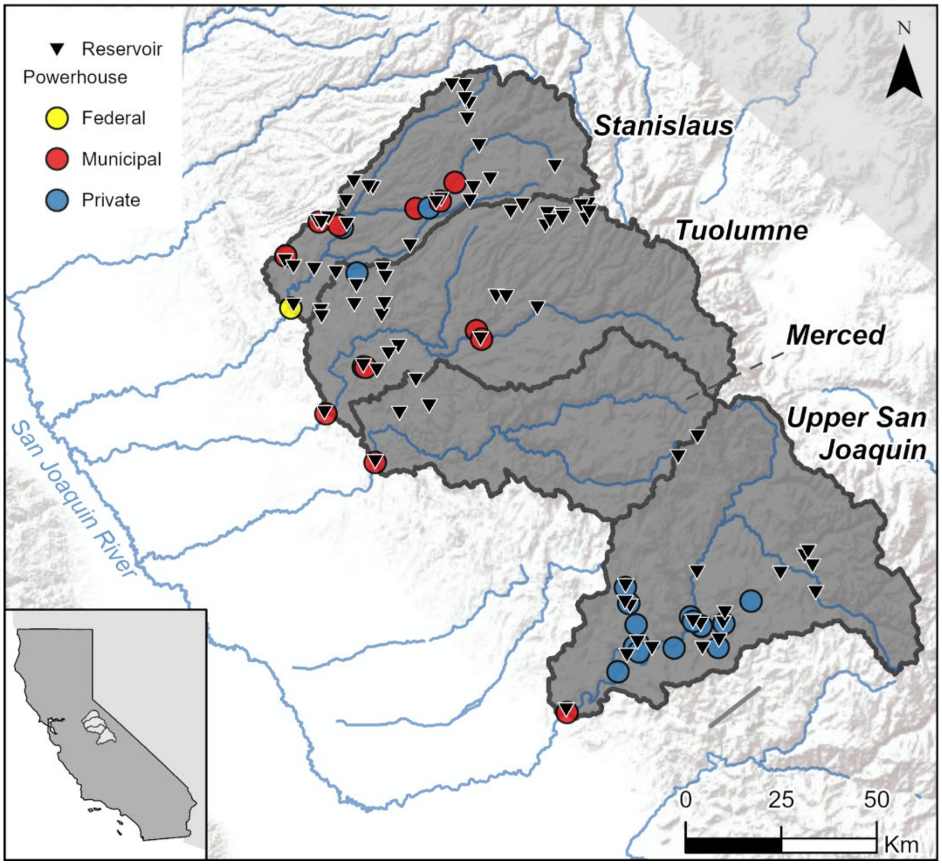
Report Scope

The CenSierraPywr model developed in this study covers the full study area of the SJR system and the facility operations therein. Chapter 2 details the model development methods as well as the requisite inputs for the generation of scenario results. Additionally, the chapter investigates the results of baseline operations with future climate's GCMs. The analysis compared the baseline outcomes with that of exclusive hydropower (fully optimized) operations as well as future relative prices. In addition to primary outputs focused on facility operations (energy generation, reservoir storage, and basin outflow), secondary outputs derived from model outputs were piloted as system "red flags". These metrics are being tested as a means of analyzing critical operational behaviors perturbed by GCMs and other model modifications. Chapter 3 presents two specific case studies developed in collaboration with the TAC which investigate potential future alterations to flow management in the system.

Study Area

This study includes the four major basins in the Central Sierra Nevada, California, that contribute to the main flow of the San Joaquin River (SJR), one of two major rivers that flow to the Sacramento-San Joaquin River Delta. From north to south, these basins include the Upper San Joaquin, Merced, Tuolumne, and Stanislaus (Figure 1). These basins are a highly regulated network of high-altitude reservoirs and hydropower facilities leading to low-altitude, multi-purpose "rim" reservoirs/dams that regulate the flow entering California's Central Valley. Along with flood control, the rim dams provide water for recreation, urban and agriculture needs for downstream communities, environmental quality, and produce hydropower. The facilities are operated by several distinct utility companies.

Figure 1: Map of the CenSierraPywr Study Area



The study area includes the four river basins: Stanislaus, Tuolumne, Merced, and Upper San Joaquin rivers. Hydropower facilities and reservoirs within each basin are also shown.

Source: National Hydrology Dataset, California Energy Commission

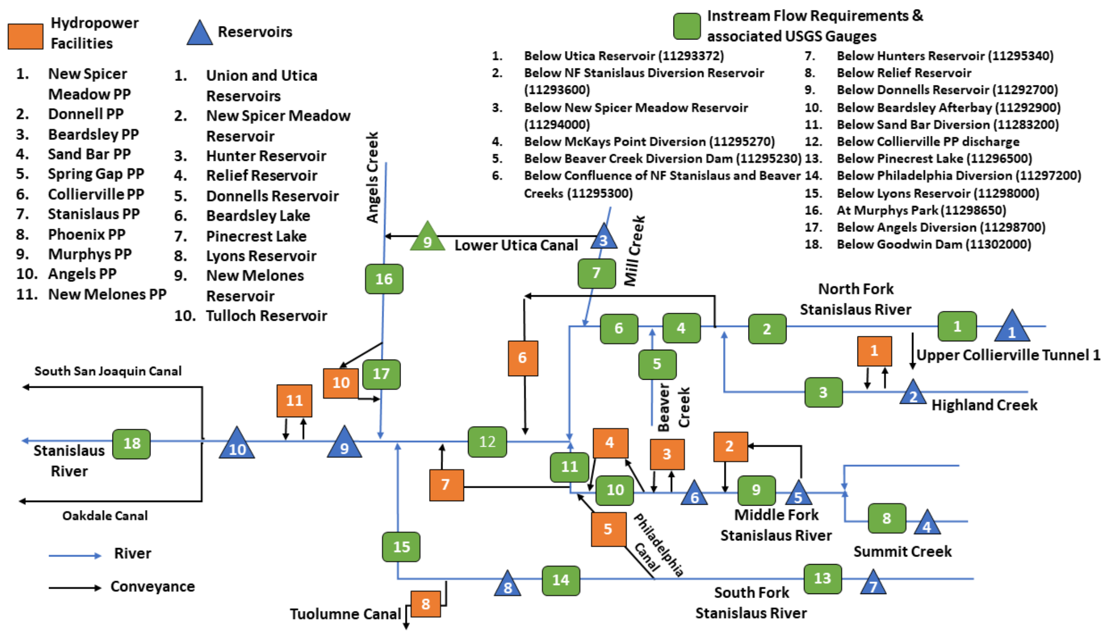
The SJR system supports one of the most agriculturally productive lands in the country, provides water to more than 4.5 million people, and has a capacity to generate 3,000 megawatts (MW) of hydropower. The region represents highly diversified reservoir and hydropower facility operations. The reservoir capacities range from less than 0.1 million acre-feet (MAF) to 2.5 MAF and the hydropower facilities range from less than 5 MW to over 500 MW. There are at least 11 utilities and energy organizations that manage the hydropower facilities in the region (Appendix A, Tables A-1 through A-8)

Historical water management activities have had an adverse impact on river ecosystems, leaving fish populations (most notably anadromous salmon, *Oncorhynchus* spp.) in a precarious state. The 2006 San Joaquin River Restoration Settlement and the subsequent San Joaquin River Restoration Settlement Act of 2009 required an improved understanding of the linkages between instream flows, fish population requirements and competing water demands for human needs in SJR. There was a renewed interest due to the recent State Water Resources Control Board (SWRCB) plan to maintain 30-50 percent of the unimpaired flows in the SJR and its tributaries (SWRCB 2018; CEFWG 2020). The management of water infrastructure is a central player in water allocation in the SJR basin. This study focuses on the four central basins of the Sierra range, that form the SJR System, as discussed below. The water system schematics were initially derived directly from the suite of WEAP models developed in previous efforts (Rheinheimer et al. 2014; Rheinheimer, Yarnell, and Viers 2013; Rheinheimer, Ligare, and Viers 2012).

Stanislaus River Basin

The catchment area of Stanislaus basin is 3,100 km^2 and the basin is drained by the Stanislaus River. The river has three main tributaries – North Fork, Middle Fork and South Fork. Large hydropower facilities contribute to about 61 percent of the capacity of the basin. The aggregated storage capacity of the basin is 2,874 thousand-acre feet (TAF). New Melones Lake is the rim dam in the basin. Tulloch Lake, which is down stream of the rim dam, along with the rim dam helps in managing the floods in the basin. Figure 2 shows a simplified schematic of the network setup for the Stanislaus basin. The Stanislaus basin is divided into 25 catchments.

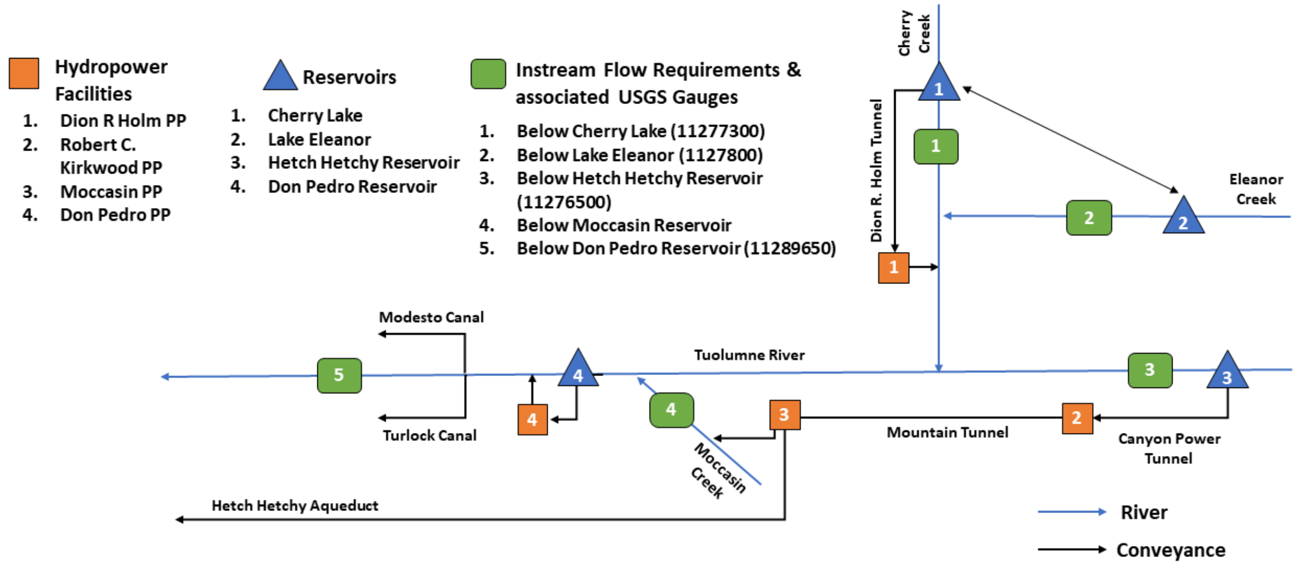
Figure 2: Schematic of the Stanislaus River Basin Water System



Tuolumne River Basin

The Tuolumne basin has a catchment of 4,851 km^2 and is drained by the Tuolumne River with its headwater originating in Yosemite National Park. The main tributaries of the river are South Fork, Cherry Creek and Clavey River. The river flows into Hetch Hetchy Reservoir, which is a major source of drinking water for the City of San Francisco. The water from Hetch Hetchy flows into Don Pedro Lake. The reservoirs in this basin are operated primarily for meeting urban water demands and flood control. The four hydropower facilities modeled in this study are large facilities (specifically greater than 30 MW capacity). The aggregated storage capacity of the basin is 2,690 TAF. Figure 3 shows a schematic of the Tuolumne basin. The Tuolumne basin is divided into 19 catchments.

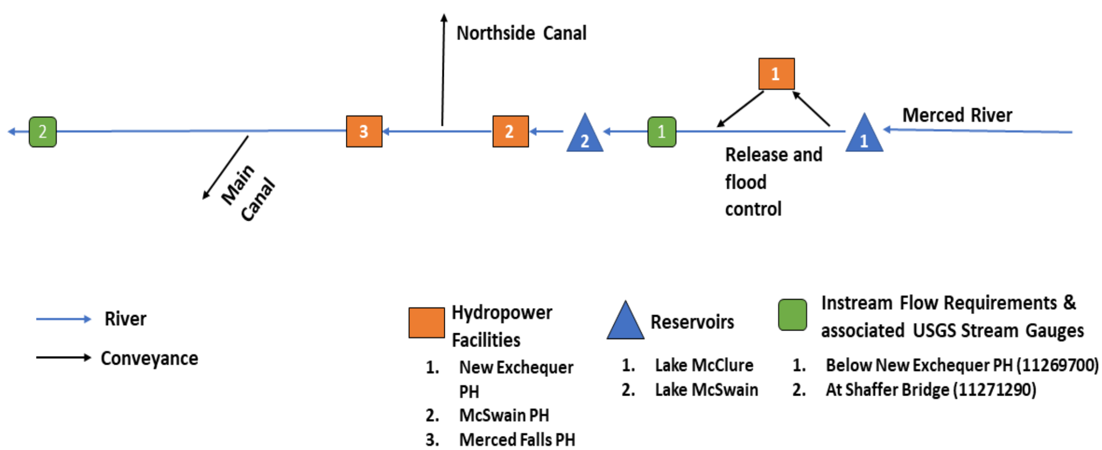
Figure 3: Schematic of the Tuolumne River Basin Water System



Merced River Basin

The Merced basin covers an area of 3,288 km^2 and is drained by the Merced River. The basin is the least regulated of all the study area basins as most of the basin is protected by Yosemite National Park. There are no high-elevation hydropower facilities in the basin. The first major obstruction to the river is at the rim dam. Nearly 95 percent of the hydropower capacity in the basin is from large facilities. The aggregated storage capacity of the basin is just over 1,000 TAF. The reservoirs are primarily operated for flood control and to meet the agriculture and urban water demands downstream of the rim dam. The basin is delineated into six catchments. A simplified schematic of the CenSierraPywr model setup is shown in Figure 4.

Figure 4: Schematic of the Merced River Basin Water System

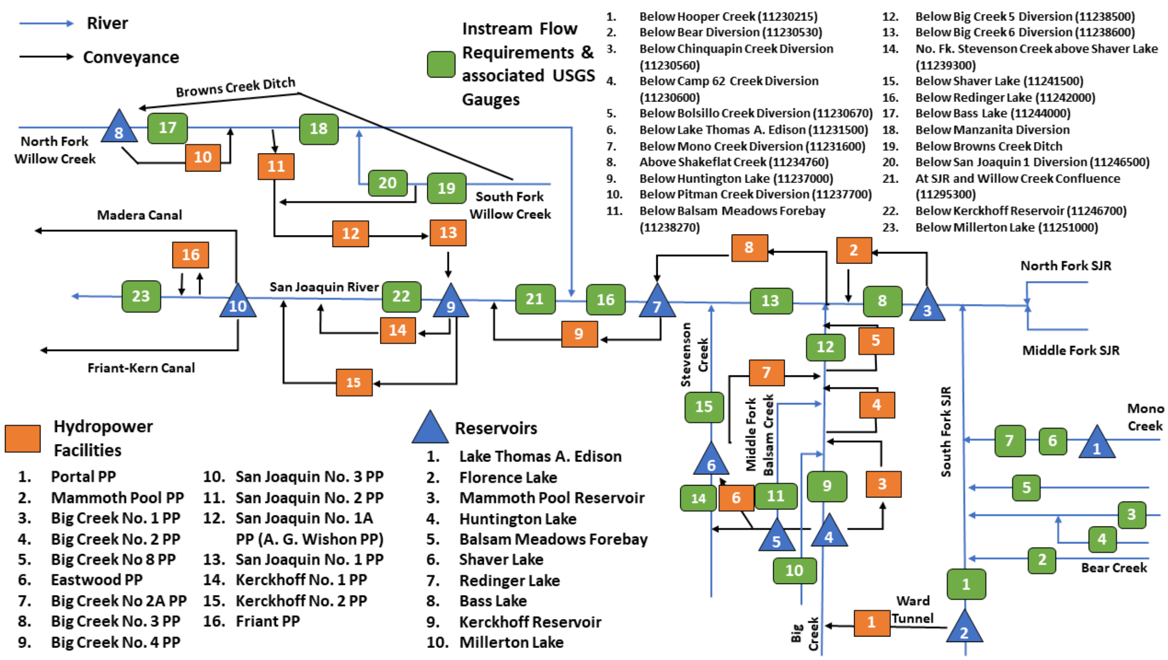


This basin is primarily unregulated until the rim dam, Lake McClure. After which, there are a series of small reservoirs to divert water for urban and agriculture use. Although, hydropower is not the primary purpose of the water release from the reservoirs, each reservoir has a hydropower facility through which water is routed to produce hydropower.

Upper San Joaquin River Basin

The area of Upper SJR basin is 4,245 km^2 and drains into the SJR. The main tributaries of the river are North Fork, South Fork and Willow Creek. There are 16 prominent hydropower facilities in this basin, including 15 high elevation reservoirs, that have been included in the study. The details of the facilities are shown in Table A1. Large hydropower facilities (specifically greater than 30 MW capacity) contribute to more than 77 percent of the hydrogeneration capacity in the basin. There are eight major high-elevation reservoirs that are primarily operated for hydropower production. Millerton Lake is the rim dam reservoir at lower elevation. Figure 5 shows a schematic of the Upper San Joaquin system as represented in this study. The basin is delineated into 38 catchments.

Figure 5: Schematic of the Upper San Joaquin River Basin Water System



CHAPTER 2: Water Allocation and Hydropower Optimization Model with Climate Change and Energy Prices

Methods

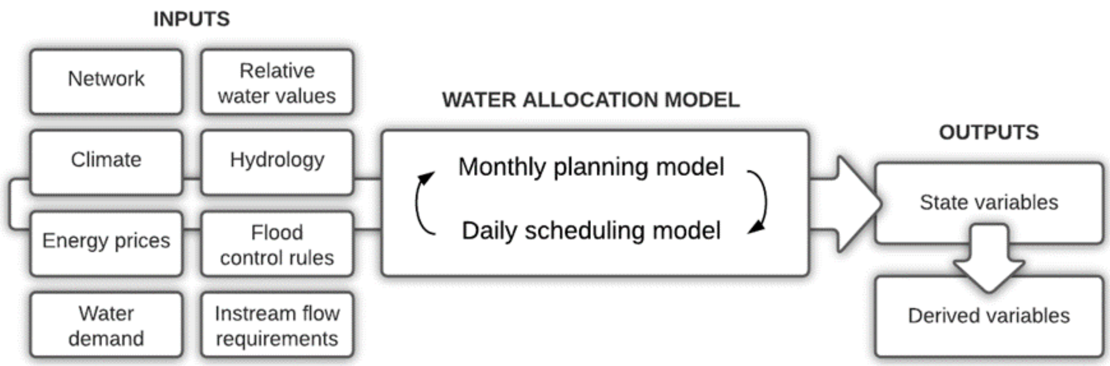
Overview of Modeling Framework

A modeling framework was developed and applied for this study that accounts for the different roles of hydropower in the four basins. The four basins represent a spectrum from hydropower dominated to non-hydropower dominated systems. The Upper San Joaquin and Stanislaus River basins are more complex and are primarily hydropower dominated in their management objectives. The Merced and Tuolumne River basins are operated primarily for agricultural and urban water demands, with ancillary hydropower production. All basins have low elevation rim dams that are operated for flood control, among the multiple purposes of their reservoirs. The significant presence of energy price-driven hydropower operations in two basins (Stanislaus and Upper San Joaquin) required including hydropower systems' economic optimization.

The central component of the CenSierraPywr modeling framework is a Water Allocation and Hydropower Optimization (WAHO) routine (Figure 6) and a daily water system simulation module that optionally includes energy price-based optimization for hydropower allocations. In all basins, the water system module allocates water using a cost-based, demand-driven linear programming-based simulation approach with *Pywr*, a Python library for modeling water systems in a flexible and extensible way (Tomlinson, Arnott, and Harou 2020), described further below. Demand and costs are defined in a variety of ways, including complex operational rules for reservoir operations (including recreation), hydropower, instream flow requirements, urban/agricultural water demand, and flood control. For hydropower dominated systems (Stanislaus and Upper San Joaquin basins), which include discretionary hydropower releases, allocations for hydropower are informed by a monthly, partial foresight optimization module with a one-year planning horizon that is re-run at the beginning of each simulation month. Importantly, the hydropower optimization, described further below, incorporates hourly regional electricity prices from the day ahead market, a key methodological advancement over previous water-focused hydropower modeling efforts in this geographic region.

The WAHO routine is loosely coupled with other model routines, including hydrology and energy components for inflow runoff and energy prices, respectively, and is connected to a graphical user interface (GUI), a database, and a code repository for data and code management. Key input to and output from WAHO's routine are summarized here, with modeling methods that depend on these input and associated data that are described below.

Figure 6: Water Allocation and Hydropower Optimization Model Framework



Framework shows integrated inputs (left), core modules (middle), and numerical outputs (right).

Inputs

The model requires several numerical and descriptive (i.e., written rules) inputs. With reference to Figure 6, these CenSierraPywr inputs include:

- *Infrastructure*: This includes the physical configuration of the system and the physical capacities of system components, such as conveyance facilities, reservoirs, and so on.
- *Relative water value*: As described in greater detail, *Pywr* requires water "cost" to be provided to allocate water appropriately. These are input to CenSierraPywr as relative water value. Although they are generally fixed, system behavior is very sensitive to relative value, a reflection of real water management.
- *Climate*: This includes temperature and precipitation. Though mostly used as input to estimate hydrology, precipitation is used directly to calculate the water year type for determining minimum flow requirements in the Tuolumne River below Hetch Hetchy Reservoir.
- *Hydrology (runoff)*: Catchment runoff, from downscaled and bias-corrected Variable Infiltration Capacity (VIC), includes surface runoff, base flow and snow melt. The impact of climate change or other climate scenarios is generally mediated through this input.
- *Energy prices*: High elevation reservoirs are typically operated to maximize revenue from hydropower production, while meeting the legal and contractual obligations for water requirements downstream and, in many cases, restrictions on certain environmentally harmful operations. Wholesale hourly electricity prices in the day ahead market drive much of the decision-making process in releasing water from reservoirs for hydropower production, though other economic incentives for ancillary services are also important. Hourly energy prices are used to develop piecewise linear price curves that are used by the WAHO routine. Prices for ancillary services were not included as a model input other than spinning reserves for some facilities.
- *Urban/agricultural water demand*: Water demand includes daily demand for both residential/urban water (such as the San Francisco Public Utilities Commission diversions from the Hetch Hetchy system) and agricultural water (for irrigation districts and Central Valley Project contractors).
- *Reservoir operations*: Reservoir operations include spill minimization reservoir level objectives for flood control, recreation and, in some instances, water supply. Generally,

reservoir operations are implemented through demand in downstream control points, such as in in-stream flood control requirement points and hydropower facilities.

- *Instream flow requirements*: Instream flow requirements (IFRs) include water to be released at specific points within natural river channels below control facilities (storage or diversion dams) to support environmental management objectives. IFRs, which may include minimum flow requirements and, optionally, ramping rate restrictions, are stipulated by FERC licenses and other agreements for those facilities not regulated by FERC.

Each of these inputs are easily modified using the approach described below.

Outputs

Outputs from CenSierraPywr include primary numerical output and secondary derived variables. Primary outputs include system state variables at any timestep, while secondary outputs are variables derived from the state variables. State variables (primary outputs) include:

- Water allocations at key points of interest (for example instream flow requirement locations, hydropower facilities, and urban/agricultural water delivery points).
- Basin outflows.
- Reservoir storage.
- Reservoir elevation.
- Hydropower energy generation.

Hydropower generation is calculated from system state using the power equation:

$$P = \eta \rho g h Q$$

where P is power (Watts), η is efficiency (assumed to be 0.9), ρ is water density (assumed to be 1000 kg/m^3), h is gross head of the hydropower turbine (m), and Q = flow through the hydropower turbine (m^3/s).

In addition, some system-specific state variables are also calculated, including the storage of the Don Pedro Water Bank in the Tuolumne River basin.

Secondary (derived) variables for this study include:

- *Uncontrolled spill below rim dams*, defined as any days where flows downstream of the dam are greater than the sum of the minimum instream flows and allowable flood control releases.
- *IFR gross deficit*, defined as the minimum flow less actual flow at IFR locations. This includes only the nominal IFR in licenses/agreements, and does not incorporate naturally low inflows, which are usually explicitly accounted for in licenses/agreements.
- *Low storage for rim reservoirs*, defined as storage less than 1/3 of capacity (less inactive pool)

The above secondary variables are also considered for potential “red flags”, as they indicate system states of potential concern and therefore are worth tracking under different climate and management scenarios.

In addition to these primary and initial set of secondary variables, input that is calculated during model run time may also be saved as a model output. For this study, instream flow requirements are calculated and saved as model output during runtime, as they are defined using rules that are calculated during run time.

Water Allocation with Pywr

The Pywr software package[6] (Tomlinson, Arnott, and Harou 2020) was used to implement both the daily and monthly system operations modules in the CenSierraPywr framework. Pywr is an open source, linear programming-based, generalized network resource allocation tool to calculate the optimal allocation of water within a water network given system constraints and water value ("costs"), defined through either numerical data or written rules, broadly similar to the method developed in WEAP (i.e., Mehta et al. 2011). Pywr implements a classical linear programming cost minimization (benefit maximization) approach to allocating flows in a network, which consists of storage nodes (reservoirs) and non-storage nodes (such as hydropower facilities or agricultural demand) connected by edges (links). Pywr has a similar modeling objective as WEAP. However, the actual computation algorithm and, therefore, some inputs, are different. Specifically, whereas WEAP relies on defining priorities for each water demand, Pywr uses relative value (or cost) of water. In contrast to priority based WEAP, Pywr is guided by hydroeconomic principles.

Pywr is ideally suited to this study in several ways, aside from its core modeling capabilities. First, if set up correctly, it is relatively fast, and can efficiently manage modeling of different scenarios easily and computationally efficiently. Second, because it is based on Python's object-oriented "classes", it can be easily extended through custom Python code to accommodate the specific modeling needs of this work. Third, Pywr is designed to optionally be used in a multi-objective evolutionary algorithm (MOEA), via a third-party Python library. This MOEA option enables advanced scenario and trade-off analyses – which is not currently integrated into this study but an area of future work.

All system characteristics and operational objectives are defined via either numerical input or rules (for example flood control operations). To support this, Pywr includes a rich syntax and programmatic approach using a combination of JavaScript Object Notation (JSON) and Python to define demands, costs and capacities in ways that align with how systems are operated. Numerical input may be specified in JSON directly or be from external .csv or Excel files. Out-of-the-box, Pywr focuses on simulation-style modeling for dynamic scheduling operations, whereby allocation decisions are made sequentially; optimization over steps longer than the simulation step requires a supplemental planning-scale optimization approach to constrain near-term operations (Zagona et al. 2001), which was achieved for optimal hydropower operations as described below. Pywr uses the GNU Linear Programming Kit linear programming solver.[7] In this study, the parallelization capability noted above is used for all grouped scenarios that are not climate-related, and on a per-basin basis; for climate-related scenarios (specifically climate change scenarios and whiplash sequences), the Pywr models are

[6] Pywr GitHub

[7] GLPK Documentation

run computationally independently, though still potentially in parallel on any given multi-CPU computer. Specific input sources and definitions are described in the following section.

Hydropower Optimization

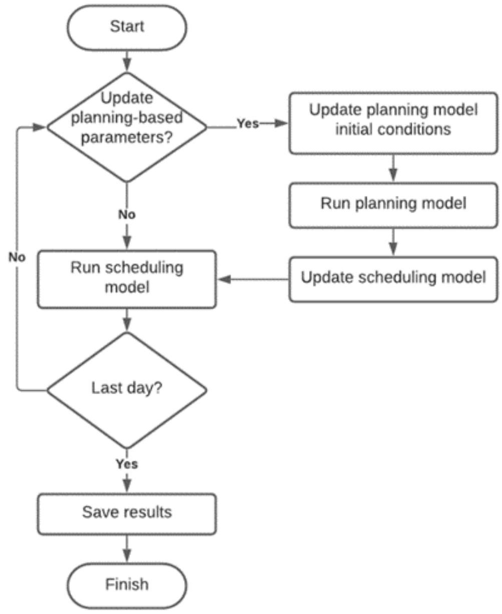
Demand for water for hydropower is not static but dependent on broader regional energy needs, wholesale energy prices, availability of other energy sources, and energy grid configuration. It is assumed that the high elevation reservoirs are operated to maximize revenue from hydropower production, given various operational constraints. This implies that hydropower operators will release water for hydropower accounting for forecasted energy prices and hydrological conditions. If energy prices are expected to go up, hydropower operators will hold the water to release later for hydropower production, if possible. This occurs at an hourly timestep across days and months.

Hydropower optimization for discretionary daily hydropower releases is achieved by using output from a 12-month, monthly timestep, planning-scale optimization model with imperfect foresight of hydrology and perfect foresight of energy prices, run anew at the beginning of each month. Generally, the CenSierraPywr hydropower optimization algorithm can be described in the following steps:

1. At the beginning of each month:
    a. Update the initial conditions of the planning module with final results from the previous day in the daily module.
    b. Run the monthly planning module.
    c. For each hydropower facility, use the first month of the planning module results to identify
        i. the optimal monthly release as a percent of hydropower capacity.
        ii. the price threshold above which it is optimal to generate hydropower.
2. For each day within the month:
    a. Identify the price duration curve for the day.
    b. For each hydropower facility:
        i. Use the price threshold from the monthly model to identify an optimal release from the price duration curve.
        ii. Also release extra available water up to the point on the price duration curve where energy prices remain positive.

The optimization method for each of the planning modules and daily modules —including derivation and price use thresholds—are described below, as is the method for linearizing price duration curves. The flow diagram for the process described is shown in Figure 7.

Figure 7: Flow Diagram for Linking Monthly Planning-Scale Optimization Module with Daily Optimization Module



Source: Josh Viers

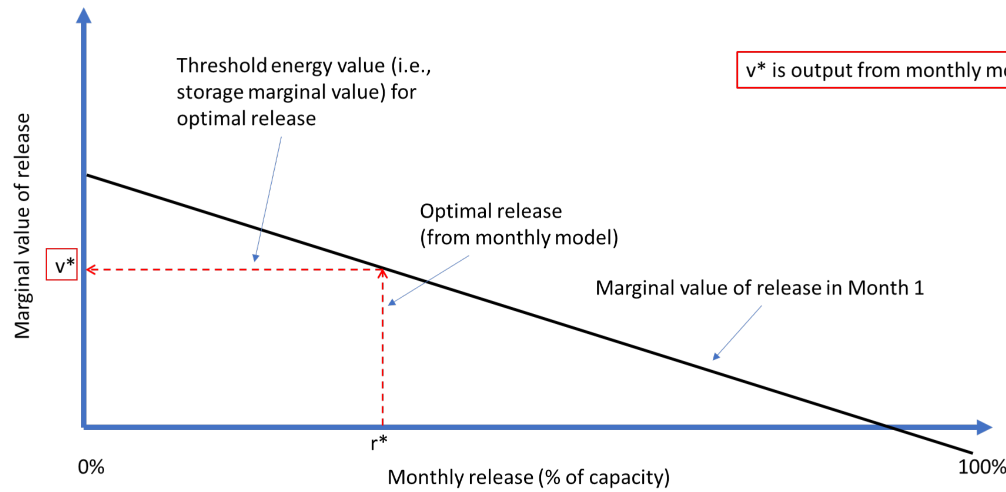
Monthly Optimization (Planning Module)

The broader objective in the monthly hydropower optimization model is to establish the day ahead market wholesale electricity price threshold during the month above which it is optimal to produce hydropower (Figure 8). The mathematical objective in the monthly model is to maximize the value of all water deliveries, including hydropower generation, subject to infrastructure constraints and operational objectives.

The hydropower optimization module begins with two key assumptions:

1. The profit-maximizing operator will generate during hours when energy prices are highest and hydropower facilities are flexible enough to turn on and off as needed, subject to other constraints. This latter assumption is only partially valid: many hydropower facilities in the study region must be manually turned on and off, but, once on, can ramp up and down quickly, such that facilities are typically kept on, even if this is economically suboptimal from a market perspective (B. Buffington, *pers. comm.*). This operational constraint is not considered for this study.
2. It is also assumed that high-elevation reservoirs can empty at the end of the one-year planning horizon with no end-of-year value for storage. This assumption is based on observations, which show that most high elevation reservoirs empty—up to a minimum volume—during at least some point within the year, though not necessarily every year. Thus, the water storage one year from the planning month has little influence on the first month of operations.

Figure 8: Calculation of Threshold Marginal Value of Energy



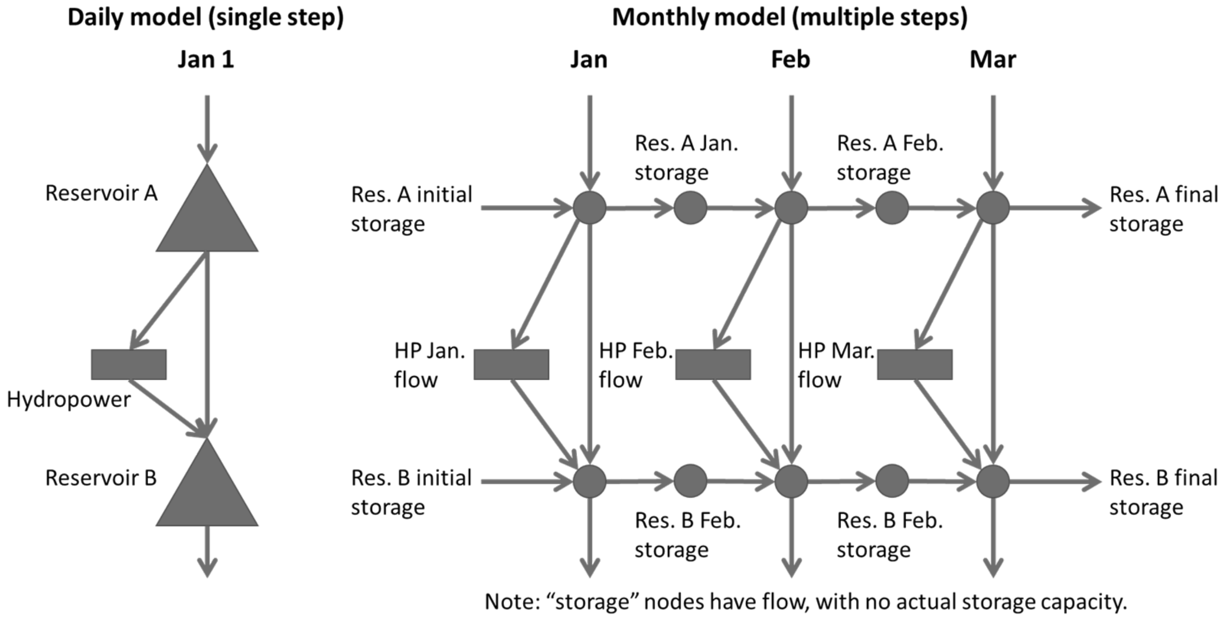
The optimal monthly release to generate hydropower based on the marginal value of the release (v*). This output is used in the daily model to n determine daily releases.

With these assumptions, monthly price-duration curves can be used as cost curves in an optimization context (Olivares and Lund 2012). Monthly price duration curves are created from hourly timeseries of price data that represent the actual bulk hydropower generation price (not necessarily associated with a specific market).

The planning module is developed as a single, cost-minimizing linear programming problem, implemented with Pywr. Optimization is achieved in the planning module using piecewise linearization of wholesale energy prices, transformed to relative costs within the Pywr model; piecewise linearization is described below. Most daily time step rules are also included in the planning module, including those that relate to well-defined operational requirements, such as instream flow requirements, urban/agricultural water demand and other requirements. Hydrological conditions are assumed to be partially known, depending on both the initial and future planning month's inflows. Future energy prices are assumed to be known with 100 percent accuracy.

For the monthly planning module, Pywr was used to create a single linear programming problem with perfect foresight. This was achieved by creating a unique, month-specific copy of each original system node, connecting each temporally adjacent reservoir-month. The conversion of the daily network to the monthly network is depicted in Figure 9.

Figure 9: Representative Example Schematics of Interconnected Reservoirs and a Single Hydropower Facility



Daily (left) and monthly (right) versions of a water system model.

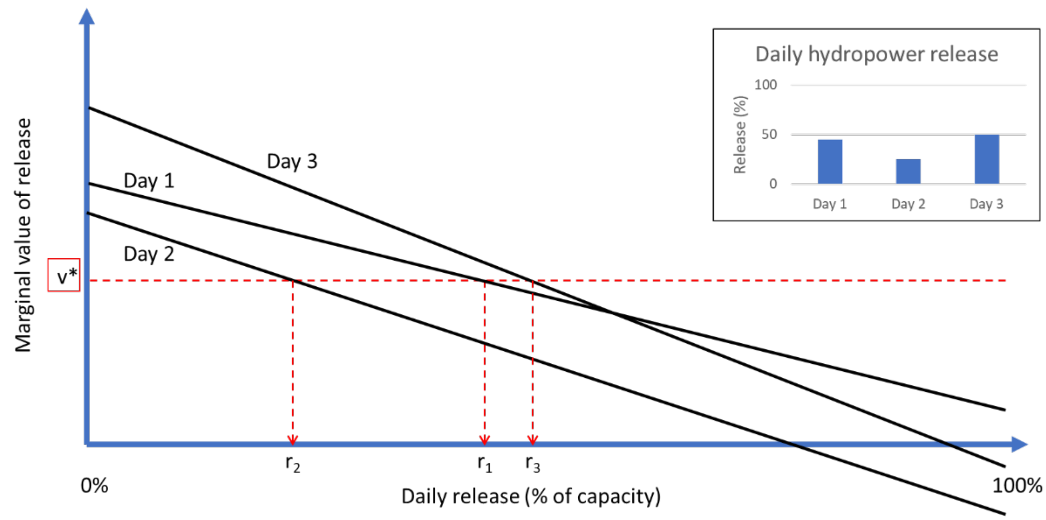
The first month's price threshold from the planning module is used as a price threshold for the daily module for that month, with the planning module run anew on the first day of each month in the daily module, similar to the approach described by Rheinheimer et al. (2016).

For input as "cost" into generalized Pywr, prices are normalized across the system. Prices are first converted to dollars per unit of volume of water (by using the hydropower production formula without head) and then divided by a common denominator (100 in this case), with the objective of hydropower cost being between that of reservoir storage (low value) and urban/agricultural demand (next highest value). Thus, cost in the model is not the actual value of water for hydropower but rather a relative value for the model to optimize allocation. Negative hourly prices are represented as positive Pywr costs and represent a penalty in the LP model for generating power. However, negative prices may be less important than other operational objectives, such as the restriction on high ramping rates associated with some facilities in the region.

Daily Optimization

Once the monthly price threshold is calculated, the same price threshold is used each day for one month. On each day during the month, the hourly price duration curve for the day is used to select the optimal release as a percentage of hydropower facility capacity, based on the month's price threshold. This is depicted in Figure 10 for three days with hypothetical price duration curves. Hydropower demand for each hydropeaking facility is defined as a constant value, equal to the turbine capacity. Because hydropower demand is already optimized with this method (subject to various constraints and objectives), Pywr cost associated with hydropower generation is fixed relative to other costs and not from piecewise linearized price curves.

Figure 10: Method to Calculate Optimal Daily Release

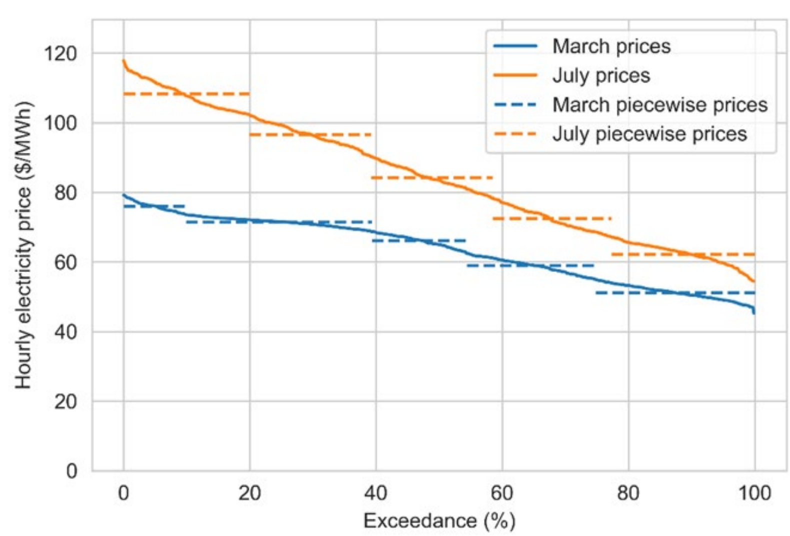


Calculations are from hourly price duration curves (black) and wholesale electricity price threshold (v*).

Piecewise Linearization

Because linear programming is used, the price-duration curves used in the planning module must be made linear from hourly price data. This was achieved by iteratively dividing observed prices into equally divided successive blocks such that the sum of each level of division resulted in minimal differences of observed prices and piecewise-averaged prices between each of the two respective blocks. An example result from this method is depicted in Figure 11 for monthly prices from the HiGRID prices dataset used in this work. Eight blocks were used.

Figure 11: Piecewise Linear Example for a Price-Duration Curve



Example five piece linearization developed for this study from the HiGRID dataset.

Specific Methods and Data

A range of specific modeling methods were used for each component of the water system model, including hydropower optimization, instream flow requirements, hydrology (runoff, snowpack, etc.), flood control, hydrology, energy prices and climate data. Each of these are described in the following sections. As noted, the WAHO modeling routine used includes a combination of rule-based and optimization-based operational logic and data from other models.

System Schematic

Melones Lake is the rim dam in the basin. Tulloch Lake, which is downstream of the rim dam, along with the rim dam helps managing the floods in the basin. The Stanislaus basin was divided into 25 catchments. The water system schematics were initially derived directly from the suite of WEAP models developed in previous efforts (Rheinheimer et al. 2014; Rheinheimer, Yarnell, and Viers 2013; Rheinheimer, Ligare, and Viers 2012). The original schematic was then extended to include rim reservoirs and downstream dependent agricultural water users (irrigation districts and the Central Valley Project), as well as downstream hydropower and instream flow requirements. Additionally, the original schematic was checked for errors and fixed as needed.

Historical Inflow Hydrology

For hydrology inputs, the model requires runoff at the sub-basin level. For this study, the team used VIC historical (1950 to 2013) daily gridded (1/16^{o}) runoff data developed by Livneh et al. (2015). Livneh utilizes the VIC hydrologic model (Liang et al. 1994), forced with observed meteorological data from NOAA/OAR/ESRL PSD, Boulder, Colorado, USA.[8] A version of the Livneh dataset clipped to California and Nevada, as developed for the project to model managed flows for the Sacramento/San Joaquin basin (Knowles and Cronkite-Ratcliff 2018) and hosted by a UC Berkeley server,[9]. The gridded runoff data was aggregated for each sub-basin in this study using ArcGIS tools. For partial grids, the majority rule was used.

The runoff timeseries was further processed for bias correction. Since the unimpaired flow data are available only at monthly temporal resolution and for the whole basin, a methodology was developed to use monthly unimpaired flow to bias correct daily runoff data at the basin level. The following steps were taken:

1. The daily runoff was first aggregated to monthly runoff.
2. The monthly runoff was then aggregated to a single location within each basin where unimpaired flow data are available. Table 1 shows the locations used for bias-correction.

Since the bias can be different for different months, the bias correction factor was calculated separately for each month. Historical unimpaired monthly data for bias correction was from the California Department of Water Resources (CDWR) (Huang 2016). The R package

[8] NOAA Physical Sciences Laboratory (PSL)

[9] Data available at the VIC Data Repository (UC Berkeley)

Hydrology and Climate Forecasting (*hyfo*[10]) was used to generate the monthly bias correction factors by using the historical unimpaired runoff as the observed dataset.

Table 1: Locations Used for Bias-Correction

Basin	Location Description (California DWR unimpaired flow (UF) basin numbers)
Stanislaus	at New Melones Reservoir (UF 16)
Tuolumne	at Don Pedro Reservoir (UF 18)
Merced	at Exchequer Reservoir (UF 19)
Upper San Joaquin	at Millerton Reservoir (UF 22)

Source: California Department of Water Resources (DWR)

The monthly bias correction factor was then applied to daily data at the sub-basin level for each month. Bias-corrected data were compared with observed and uncorrected modeled data. Four metrics were used to measure the performance of bias-correction:

1. Root Mean Square Error (RMSE): This also measures an average error but follows a quadratic scoring rule. It is a square root of average of squared error, thus giving higher weightage to larger errors. It is calculated as follows:

$$RMSE = \sqrt{\frac{1}{n}\sum_{j=1}^{n}(y_j - \hat{y})^2}$$

Where j is year; n is the total number of years (sample size); y_j is flow in year j; and $\hat{y}$ is the average of flow across years. The range of both the metrices are from 0 to infinity. In some cases, RMSE has been standardized by the standard deviation (RSR).

2. Nash-Sutcliffe Model Efficiency Coefficient (NSE): This measures the degree of variance, comparing the degree of error variance in the modelled time series to that of the observed time series.

$$NSE = 1 - \frac{\sum_{i=1}^{n}(y_i^o - y_i^s)^2}{\sum_{i=1}^{n}(y_i^o - y_{mean})^2}$$

3. Percent Bias (PBIAS): the mean tendency of the modeled data to differ from observed as well as the directionality of that difference. Positive values indicate an underestimation and vice versa.

$$PBIAS = \frac{\sum_{i=1}^{n}(y_i^o - y_i^s) * 100}{\sum_{i=1}^{n}(y_i^o)}$$

Where y^s is modeled and y^o is observed time series, while y_{mean} is the mean observed discharge for the period. Target values for NSE and PBIAS are 0.

In addition to basin-wide bias correction described, specific sub-basins within several basins were further corrected using a combination of methods, including scaling and empirical quantile mapping (EQM) using the package *hyfo*. These basins were in the upper watersheds and were corrected to improve downstream hydrology (Table 2). Gap-filling improved the

[10] hyfo Githib

utility of inconsistent observed datasets while EQM moderated extreme high and low runoff events in the simulated datasets.

Table 2: Sub-Basins Selected for Targeted Bias-Correction

Basin (sub-basin UF)	Description
Tuolumne (10)	Cherry Lake (USGS 11277300)
Tuolumne (13)	Hetch Hetchy (USGS 11276500)
Tuolumne (11)	Lake Eleanor (USGS 11278000)
Upper San Joaquin (36)	Bear Creek (USGS 11230500)
Upper San Joaquin (38)	Florence Lake (USGS 11230070)
Upper San Joaquin (22)	Granite Creek at Timber Knob
Upper San Joaquin (31)	Lake Thomas A Edison (USGS 11231500)
Upper San Joaquin (23)	Miller Crossing (USGS 11226500)

Source: US Geological Survey (USGS)

Reservoir Operations and Flood Control

Reservoir operations refers to the control of system components to meet reservoir level management objectives. Such objectives are for spill minimization, recreation, water supply management, or flood control or all the options. In all cases, reservoir level objectives are achieved in the model by setting appropriate demands for water at downstream locations, with a dependency of such demands on reservoir level.

Spill Minimization

Reservoirs are managed indirectly and directly for spill minimization. Spill minimization is achieved in the model in three ways. First, spill is implicitly minimized temporally and spatially through the hydropower optimization model. The optimization model, by definition, will seek to maximize overall value. Since spill has no value, and in fact represents an opportunity cost, it will necessarily be minimized. Second, storage costs are strategically assigned to have a low negative cost (positive value), to ensure reservoirs are filled if all other demands are met. Generally, storage costs are fixed for each reservoir in time. Finally, uncontrolled releases into rivers below flood control reservoirs are penalized explicitly.

Recreation Levels

Reservoir levels for recreation exist for some high elevation reservoirs. Reservoir levels for such configurations are maintained by controlling the downstream hydropower facility. For example, levels of Pinecrest Lake, a popular vacation destination during the summer, are maintained by limiting releases through Spring Gap powerhouse to one half of its capacity during the summer.

Water Supply Management

The San Francisco Public Utilities Commission operates the Hetch Hetchy water supply system (the Tuolumne River basin) partly to fill Hetch Hetchy Reservoir by July 1 for water supply management. This is achieved in the model with forecasting inflows to Hetch Hetchy, and adjusting maximum releases to the San Joaquin Pipelines, which deliver water to the Bay Area, accordingly. No other reservoirs are explicitly operated this way in the model, though this July 1 fill target is common in the Sierra Nevada generally.

Flood Control

Flood control operations are implemented using a "Flood Control Requirement" node below each respective rim dam. The flood control requirement specifies the amount of water that should be released for flood control purposes, described programmatically, depending on the river. Flood control rules are derived from the U.S. Army Corps of Engineers (USACE) Water Control Manuals for each respective river. Based on discussions with reservoir operators, the rain flood space in each reservoir was used as a strict requirement, such that whenever the reservoir level increases to above the rain flood space curve, water is released the next day to reduce the reservoir storage. In contrast, the snowmelt flood space is not considered a strict requirement since snowmelt is assumed to be predictable. This allows the reservoir to fill early if less snowmelt is anticipated or, conversely, empty significantly if more snowmelt is anticipated. This modeling approach, which deviates from the graphical approach described in the USACE Water Control Manuals, was confirmed as appropriate in discussions with flood control reservoir operators.

The exact algorithm for the flood control release requirement is reservoir-specific and omitted here, but the release depends on reservoir storage, anticipated inflows over the next week, the maximum flood control limit in the river, and irrigation demand. Upstream reservoir storage space is also accounted for in the case of Millerton Lake (Upper San Joaquin River). Downstream instream flow requirements are not considered, as the model will release the greater of any two or more releases in a river.

In all cases, it is assumed that hydropower is maximized during both controlled and uncontrolled spill from rim reservoirs. To achieve this, the flood control requirement node is located downstream of two parallel nodes below the reservoir: a hydropower node and spillway node. The hydropower node has a slight positive value (negative Pywr cost), while the spillway has a high negative value (positive Pywr cost). Hydropower generation will thus always be opportunistic during flood control operations (and other releases downstream), and the spillway will be used when releases are higher than hydropower capacity.

Flood control reservoirs (rim reservoirs) are also operated to gradually reduce the reservoir level during the drawdown period from summer to fall. This operational objective was achieved by including a flood control release requirement during the drawdown period based on an anticipation of total inflow and storage objectives.

Instream Flow Requirements

The model includes instream flow requirements (IFRs) at various locations in the stream network and consist of a minimum flow requirement and any (or none) of a maximum flow, ramp up rate and ramp down rate. IFRs are input in the model as an IFR node, which has a minimum and maximum flow requirement and a cost for both not meeting the minimum requirement and exceeding the maximum requirement. Ramping rates, if any, are defined by specifying the minimum/maximum requirements as a function of flow during the previous timestep. Thus, IFRs are not hard constraints, but rather valued in a manner similar to other water demands such as agricultural demand and hydropower.

For this study, baseline IFRs are from FERC licenses (in the case of IFRs associated with FERC-regulated hydropower projects) or other agreements. Detailed information on IFRs, including their associated FERC licenses and source of information, are in Tables C-1 to C-4. These requirements are legally bound to the hydropower/facility operators. Thus, in the model, the IFR violation costs were set high relative to other costs in the system.

Energy Prices

Energy prices are a key input to the hydropower optimization routine described above. In this study, the energy prices are from the HiGRID model, developed by UC Irvine (Eichman et al. 2013). HiGRID was developed as a platform to analyze the impact of renewable energy development on operation and performance of grid. The model forecasts net energy load (total demand less production by renewable sources) and energy pricing resolved at the hourly timestep and the contribution from different energy sources. Using the renewable generation profile, the model forecasts the hourly net energy load (specifically gross energy load less renewable energy production) for California. The net energy load is used to derive Locational Marginal Price (LMP), which is the price of electricity that is settled /cleared in the electricity market between power plant owners and load serving entities (utilities). Historical data from the California Independent System Operator (CalISO) Open Access Same-time Information System (OASIS) is regressed to develop relationship between LMP, net load and renewable generation. This relationship is used to predict future energy pricing under different net load profiles and electric grid configurations.

Hydropower (Ancillary Services)

Generally, ancillary services are not included in the hydropower component of the WAHO model, due to the additional complexity required in implementing them. However, in some cases spinning reserve was included by adding a low-level hydropower demand of relatively high negative cost, ensuring a minimum hydropower output. The general lack of ancillary services in the study was discussed with utility operators, who confirmed that hydropower operations would be mostly reasonable without ancillary services (specifically based on day ahead market prices only), the inclusion of spinning reserve in some instances notwithstanding. Better representation of ancillary services is needed, particularly as they are expected to provide a higher value to hydropower operators in the future as the energy system in California transitions to a low carbon future.

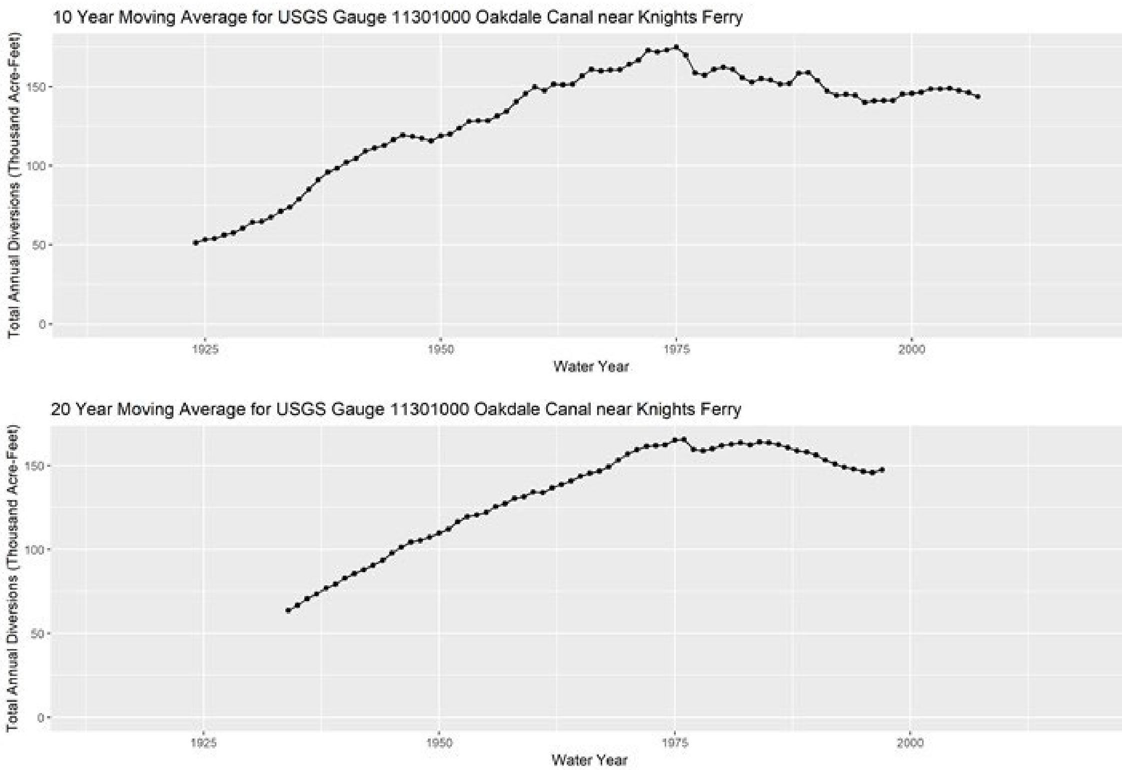
Water Demand

Water demand was approximated in several ways. First, demand for irrigation districts and the Central Valley Project was estimated using historical daily averages for each major diversion canal, classed by the San Joaquin Valley Water Year Type. To accomplish this, historical daily averages were from the USGS gauge data for each respective diversion canal. One challenge associated with this approach is the nonstationary nature of agricultural diversions. This nonstationary nature is due to general changes in agricultural production over time and changes in infrastructure (such as the filling of a reservoir). Without an agricultural production model, we selected a historical time span based on visual inspection of the historical diversions, using 10- and 20-year moving averages, opting for a historical period that broadly represents recent operations. As an example, Figure 12 shows the 10- and 20-year moving average of Oakdale Canal diversions near Knights Ferry (Oakdale Irrigation District, Stanislaus basin). As shown, the diversions levelled off in 1975 after a long period of increase.[11] Though diversions subsequently decreased, this 1975 diversion was taken as the start date for the

[11] New Melones Dam was completed in 1978 and New Melones Lake was ultimately filled in 1983.

period-of-record. This method captures recent historical averages, but does not capture the annual variation in diversions nor the representativeness of the approach changes over simulation time. Further improvements are needed to represent irrigation demand more accurately. Table 3 shows the diversions considered for the four basins in this study and the start date used to process the historical data.

Figure 12: Plot of Moving Average of Diversion in Oakdale Canal in Stanislaus River Basin



The ten years (top) and 20 years (bottom) of the average diversion in the Oakdale Canal near Knights Ferry for Oakdale Irrigation District.

Source: US Geological Survey

Second, demand for San Francisco Public Utilities Commission (SFPUC) diversions to the Bay Area via the San Joaquin Pipelines (Tuolumne River basin) were represented by establishing and adjusting total annual demand, with a fixed daily percentage of annual demand. This is the approach WEAP uses (Yates et al. 2005). Total Annual demand and daily variations were based on historical data received from SFPUC for Rheinheimer et al. (2014). Finally, demand for Groveland, a retail customer of SFPUC in the Tuolumne basin, was assigned a constant value.

Table 3: Diversions Considered for Water Demands from the Basins

River Basin	Canal Name	USGS Gauge Number	Destination(s) of Diverted Water	Selected Start Year	End Year
Stanislaus	South San Joaquin Canal	11300500	Oakdale and South San Joaquin Irrigation District	1975	2018
	Oakdale Canal	11301000	Oakdale Irrigation District	1975	2018
Tuolumne	Modesto Canal	11289000	Modesto and Waterford Irrigation Districts	1955	2018
	Turlock Canal	11289500	Turlock Irrigation District and to supply town of La Grange	1955	2018
Merced	Northside Canal	11270800	Merced Irrigation District	1987	1994
	Main Canal	11271045	Merced Irrigation District	1987	1994
Upper San Joaquin	Madera Canal	11249500	Irrigation between San Joaquin and Chowchilla Rivers	1970	2018
	Friant-Kern Canal	11250000	Irrigation in upper San Joaquin Valley	1970	2018

Source: US Geological Survey

Relative Water Value

Relative water value ("costs" in *Pywr*) was selected through modeler expertise and a general understanding of priorities in the region. In general, water value was assigned in the following order of priority (first item with the highest value):

1. Flood control
2. Instream flow requirements
3. Water demand (urban and agricultural)
4. Hydropower
5. Reservoir storage
6. Uncontrolled spill

Actual costs within this general ordering varied, with values adjusted to better represent observed historical system operations. Setting relative water value is broadly similar to the approach described for WEAP priorities in Rheinheimer et al. (2014). Some facilities/operations required more than one value for piecewise linearization of cost functions. For example, IFRs required a low flow value (generally very high), a high flow value (also generally very high), and a value for between low and high flow (generally set to zero, or no specific value). Actual values are omitted here, but are available in the source code, described in the next section.

Model Code and Data Management

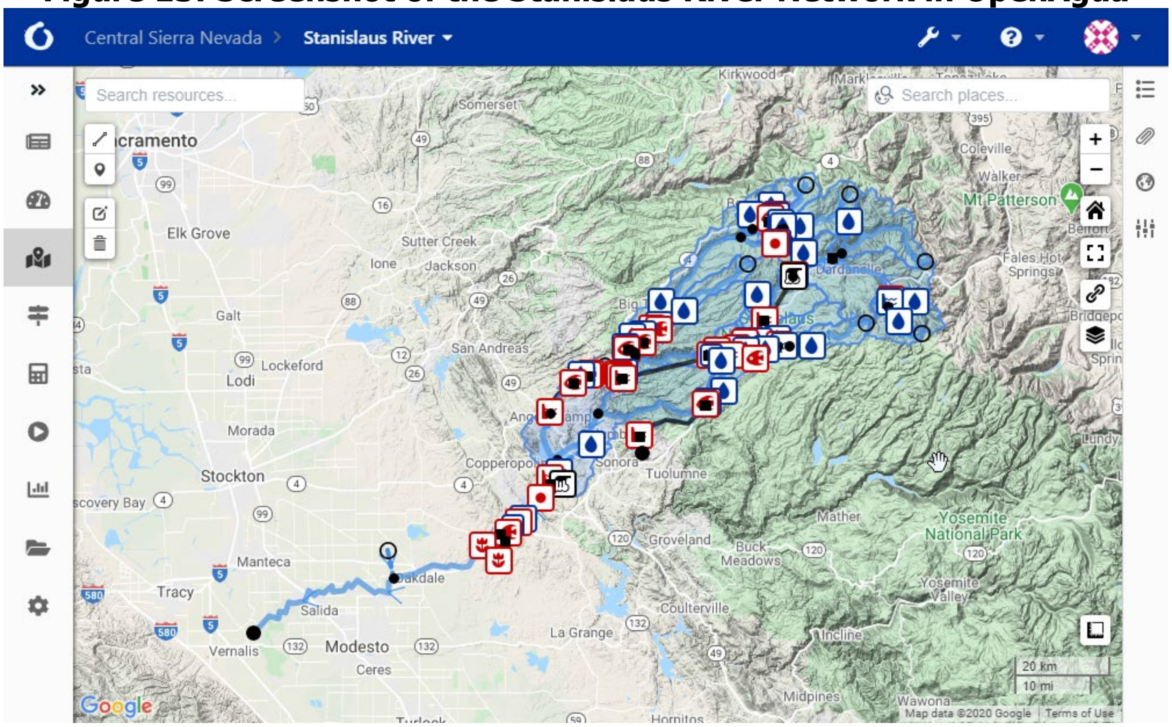
Management of CenSierraPywr model code and data are an important aspect of modeling complex systems, for transparency, reproducibility, and long-term model sustainability. All model source code is hosted in GitHub in a publicly accessible code repository (https://github.com/vicelab/sierra-pywr). The CenSierraPywr repository includes core model code used to define the *Pywr* modules, as well as code for preprocessing and postprocessing (such as figure creation).

CenSierraPywr input data—including original time series data and preprocessed input data—is not stored in a publicly accessible place. Instead, original time series data are from public sources documented in this report. Since the preprocessing code is also publicly available in the code repository, all input data are effectively reproducible from public sources/code.

Graphical User Interface: OpenAgua

In this study, an open-source software platform called OpenAgua was used as a web-based interface to the Pywr schematic. The OpenAgua platform consists of a web-based graphical user interface (GUI) linked with multiple databases and a user-defined model engine (in this case, the CenSierraPywr model described). An example screenshot of the Stanislaus River system is shown in Figure 13.

Figure 13: Screenshot of the Stanislaus River Network in OpenAgua



OpenAqua is the graphical user interface used to create the system schematic and Pywr files used in this study.

Source: www.openagua.com

A key design principle of OpenAqua is the separation of the GUI from the model engine. This allows the GUI to be relatively lightweight, and accessible on a range of devices (from smartphones to desktop computers). Data stored on the OpenAqua server can be accessed outside of the application via the OpenAgua web service and converted into the input files needed for a model engine such as Pywr. Because of this design's principle of modularity, the CenSierraPywr model generated for this work can be saved and run independently from OpenAgua, as has been done during model development in this work.

The GUI helps the modeler create the water system network (nodes and edges) including creating scenarios and management options and entering parameters and modeling logic. The interface is connected to multiple databases including, in particular, the Hydra Platform database (Knox et al. 2019) to store water resource network information. In this work, OpenAgua was used primarily to generate the model schematic, with full integration anticipated in future work.

Climate Change and Hydropower-only Scenarios

A core motivation of this study is to better understand the effects of climate change on the basin infrastructure — including hydropower in particular — in the study region and to quantify the baseline effect of instream flow requirements on hydropower production. Each of these are described below, including methods, data, and implementation.

Climate Change Scenarios

Four GCM-based climatic scenarios are considered in addition to the historical climate used by the Livneh runoff dataset described above. These scenarios are used as meteorological forcings in a VIC hydrological model. The GCMs (4 core) and their corresponding end-of-century comparative outcomes are shown in Table 4. To provide a more complete picture, six other GCMs recommended by the CCCA4 were also added (listed from drier to wetter): ACCESS1-0, CMCC-CMS, GFDL-CM3, CCSM4, HadGEM2-CC", CESM1-BGC.

In assessing scenarios, a representative historical period and representative future period across all GCM scenarios were selected:

- Historical (1981 – 2010): This period includes a wide range of water year types. Shorter time periods may skew the results if there are multiple dry or wet years.
- Near Future (2031 – 2060): This period was selected because to see trends for climate change, longer time periods are required. Also, from a policy perspective, the next three to four decades are critical for mid-term planning.

Table 4: Four Core World Climate Research Program Coupled Models

General Circulation Model	End-of-century outcome
CanESM2	Middle
CNRM-CM5	Cool/Wet
HadGEM2-ES	Warm/Dry
MIROC5	Diversity

Intercomparison Project Phase 5 (CMIP5) projections and representative concentration pathways (RCP) prioritized in this study.

Source: 4th California Climate Change Assessment

The rationale for the selected four priority GCMs is as follows. Pierce et al. (2016) downscaled projections (1/16° spatial resolution) from 32 GCMs and two future climate forcing scenarios—Representative Concentration Pathway (RCP) 4.5 and RCP 8.5 respectively—from the Climate Model Intercomparison Project, version 5 (CMIP5) archive. A list of 10 GCMs relevant to California's situation for CCCA4 was eventually developed. Based on a further set of criteria, the CCCA4 suggested four scenarios that represent different outcomes for California, which are emphasized in this study, though results are presented for all ten GCMs.

The State of California set up a Climate Action Team (CAT) Research Working Group, as the Steering Committee for the CCCA4. In consultation with Scripps Institution of Oceanography, the California Department of Water Resources, the California Energy Commission, the Governor's Office of Planning and Research, and California's Natural Resources Agency team came up with a new list of four GCMs (different from Pierce et al. 2016) based on a different set of criteria (Climate Action Team Research Working Group 2016) and an extended timeline (Bedsworth et al. 2017). The CAT also suggested to use RCP 8.5 for studies up to 2060 and to use both RCPs (4.5 and 8.5) for studies that span beyond 2060. The Climate Action Team's list of GCMs was used in this study, with RCP 4.5 and 8.5. Appendix C gives a more detailed description of the GCM selection process, including descriptions of each of the four used in this study.

For climate change impacted runoff, VIC output generated by the Scripps Institution of Oceanography at the same spatiotemporal resolution as the historical dataset (daily; 1/16^{o}) using downscaled meteorological forcings from the GCMs was used.[12] The GCM outputs utilized by this model were downscaled using the Localized Constructed Analogs (LOCA) method. LOCA is a statistical downscaling method that uses analog days from observations (picked by a model in the region with positive correlation) for downscaling and performs better for extreme conditions (Pierce, Cayan, and Thrasher 2014a). The climate change data are available from 2006 to 2100 (2099 for some GCMs). GCM-based runoff was bias corrected for this study in a manner like the historical runoff described, with monthly GCM runoff from Scripps Institution of Oceanography.[13]

To isolate the impacts of climate change alone on hydropower production, only one energy price scenario, year 2009, was considered. The 2009 water year was used as a calibration period for the HiGRID model, the source of price data for the WAHO routine.

To implement climate change scenarios, all climatic and hydrologic data, including runoff and precipitation (the latter is needed for calculating the IFR below Hetch Hetchy in the Tuolumne River), was replaced by its GCM/RCP-equivalent.

Hydropower-only Scenario

To isolate the interaction effects of GCMs and regulatory constraints on hydropower operations, the study also compared changes under a hydropower-only scenario in which all IFRs were removed from the model. This was implemented by setting minimum flow requirements to zero and likewise removing any minimum and maximum ramping rate requirements. The intent of this scenario is to isolate the effects of a purer optimization, from the "realistic" optimization explicit to the project intended to better integrate stakeholder interests and needs by producing a more realistic partial optimization model that considers legal and institutional constraints in hydropower management. The comparison between the hydropower-only optimized model with the more realistic partial optimization model can better identify more potentially feasible options for implementation of optimized operations.

Hydrologic Analysis

For a better insight on environmental recommendations, Indicators of Hydrologic Alterations (IHA) were used to assess flow alterations in riverine systems. The IHA metrics, developed by Richter et al. (1996), were run through the *IHA* R package (Law 2013; R Core Team 2019). Time series of unimpaired (modeled full natural flow) and impaired (modeled regulated) flow at the outlet of four basins were used to calculate the selected IHA metric (Table 5) to better

[12] Data available at LOCA VIC Repository (UC Berkeley)

[13] Data available at Scripps Streamflow Repository (UC Berkeley)

understand the timing and magnitude of extreme events alongside general patterns of hydropower production and water storage.

Table 5: List of Indicators of Hydrologic Alterations Metrics Used for Assess Flow Alteration and Impacts

Metric Group	IHA Metric
Group 4: Frequency and duration of high and low events	High pulse number (count), length (days)
	Low pulse number (count), length (days)
Group 5: Rate and frequency of flow condition changes	Rise rate (cms)
	Fall rate (cms)
	Reversals (count)
The magnitude of extreme flow conditions	Annual peak flow (cms)
	Annual low flow (cms)

cms = cubic meter per second

Source: modified from Richter et al. (1996)

Integrated Modeling Framework

The modeling framework used integrates several independent models, modules, algorithms, datasets and routines which are further described in this section, and referred to as CenSierraPywr throughout the report. This singular term is intended to capture the OpenAgua front-end, Pywr back-end, WAHO routine, HiGRID energy demands, down-scaled and bias-corrected VIC inflows, and all other components as specified for the four study basins.

The open access python code and documentation are available on GitHub.

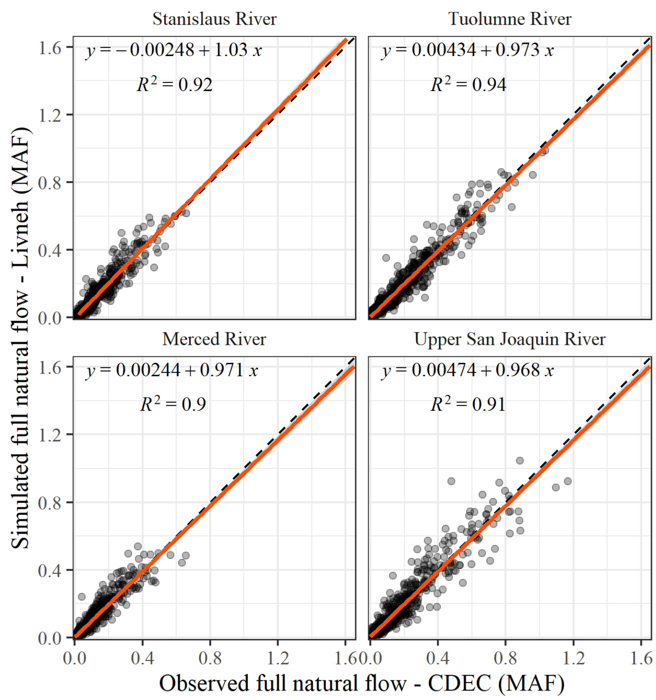
Results

Model Performance

Bias Correction

Flow from each sub-basin was bias corrected against the reference flow data (as presented in Chapter 2) and succeeded in improving model performance. Basin-scale correction resulted in R^2 values between 0.9-0.94, indicating good fit, however, variation by month and facility occurred (Figure 14). Bias corrected reference flow data improved the application of hydrology to the system, however, the limitations of the sub-basin hydrology combined with the simplification of facility operations warranted an assessment of overall model performance. The performance metrices for the bias correction for historic and GCM driven hydrological data are shown in Appendix D (Table D-5). Smaller value of RMSE and MAE indicate better fit. In general, the RMSE and MAE decreased after bias correction, indicating improvement in the hydrological data. As can be seen from the graphs, there was negative bias for low flows, which was improved after the correction.

Figure 14: Calibrated Model Performance



Performance of calibrated simulated monthly full natural flow (Livneh 1950-2013) compared with historical gauge data for each basin.

Source: Historical data from the California Data Exchange Center (CDEC).

Model Validation

The simulated historical output was compared to observed data for all available facilities and operations. On average, rim dam reservoirs are better represented than higher elevation facilities, for storage and energy. The values shown in Appendix D Tables D6-D10 provide a numerical estimate of the goodness-of-fit with observed data, however, there are several factors that may affect the performance metrics of a simulated operation.

Simulated baseline operations are often inconsistent with historical operations in the basins. During the record period (1951-2013), operations at many facilities were substantially altered with updates to regulatory requirements. Although the record provided critical information for the development of the simulations, the performance metrics were likely to produce inflated errors. Similarly, many of the operations modeled have relied on nonformulaic operator decisions which appear in the historical record as unreproducible results.

Although bias correction has improved some hydrological aspects of simulated flow, the limitations of sub-basin hydrology invariably impact model performance. Sub-basin bias corrections were introduced to all basins, in particular the Tuolumne and the Upper San Joaquin, to improve the hydrology (Appendix D). However, runoff events with persistent impacts on facility operations may be reflected in model performance metrics. The metrics were used to assess areas of concern but were not used to invalidate data. As a tool of model development, the metrics have served to draw attention to successful simulations and to contextualize results for poorly represented facilities.

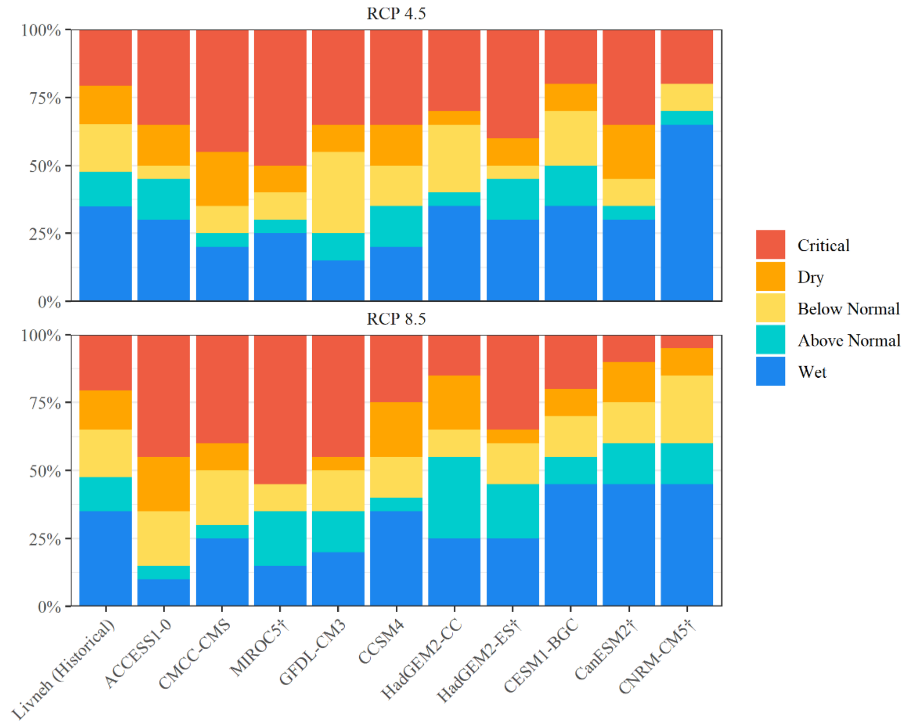
Regional Impacts

Impact of Climate Change on Hydrological Conditions

The group of modeled future climate change will affect the volume and timing of runoff in each of the basins. Although these impacts will differ over water years, changes to flow pattern occur irrespective of the GCM scenario. The change in flow volume can be characterized by the water year type (WYT) San Joaquin Valley Index (SJVI) distribution throughout the modeled period (historical and near future, 2031 – 2060) (Figure 15). RCP 4.5 mirrors a historical distribution of extreme years while RCP 8.5 suggests a more extreme deviation from the historical norm, either towards dry or wet years. The results of this distribution are mixed and the cumulative impact of these potential future time series will vary between basins and facilities. Results from RCP 4.5 (Appendix E) differed from RCP 8.5 in magnitude rather than in trend.

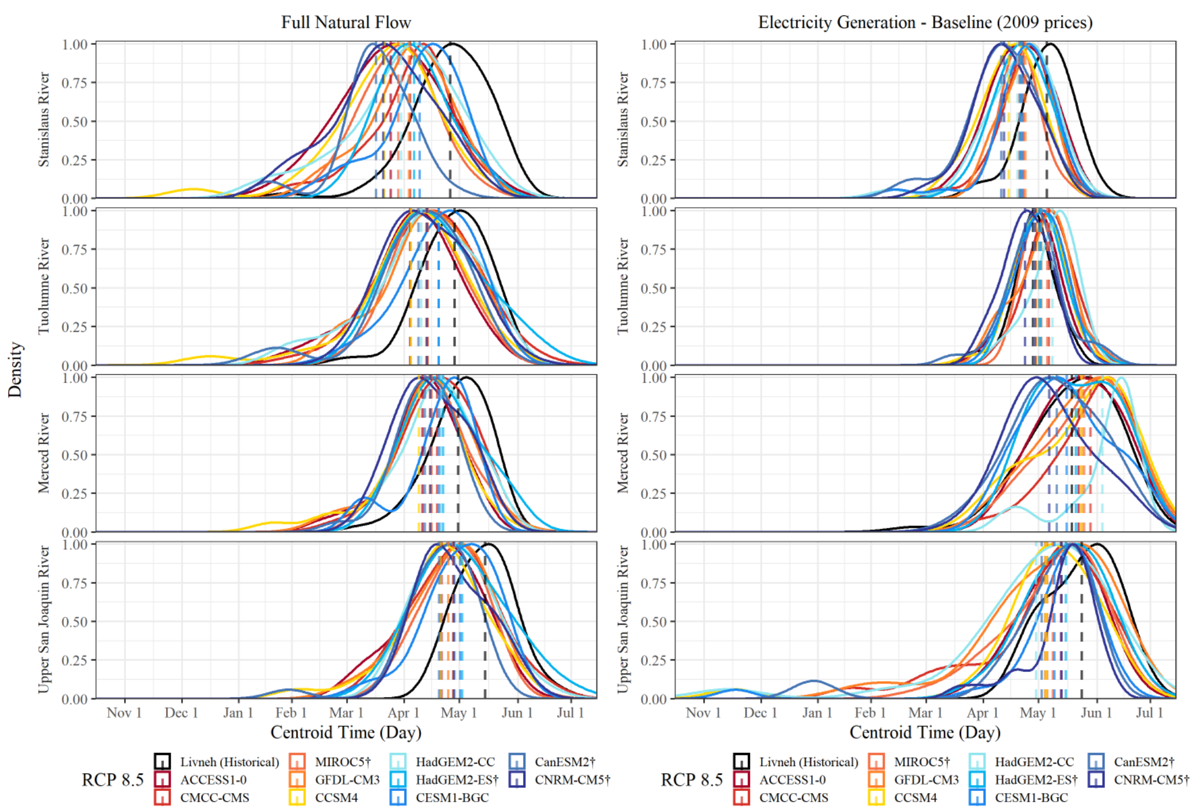
The timing of flow will also be altered by climate change. On average, RCP 4.5 and RCP 8.5 indicate an earlier runoff in the basins for all future scenarios (Figure 16, left). The impact of the mean change in centroid timing was reflected in the centroid of energy generation (Figure 16, right), however, centroid energy production shifted energy production 2-4 weeks earlier in line with centroid flow found in hydropower-optimized basins (Stanislaus and upper San Joaquin). Non-optimized basins (Merced and Tuolumne) exhibited earlier centroids for wetter GCMs and later centroids for dry GCMs. The impact of the change in WYT and runoff timing alter the mean 30-years of total annual energy production of the system by -29 percent to 10 percent (Figure 17) and storage by -13 percent to 12 percent (Figure 18). When 2045 prices were used in the model in place of the default 2009 prices, the change was insignificant.

Figure 15: Distribution of Water Year Types



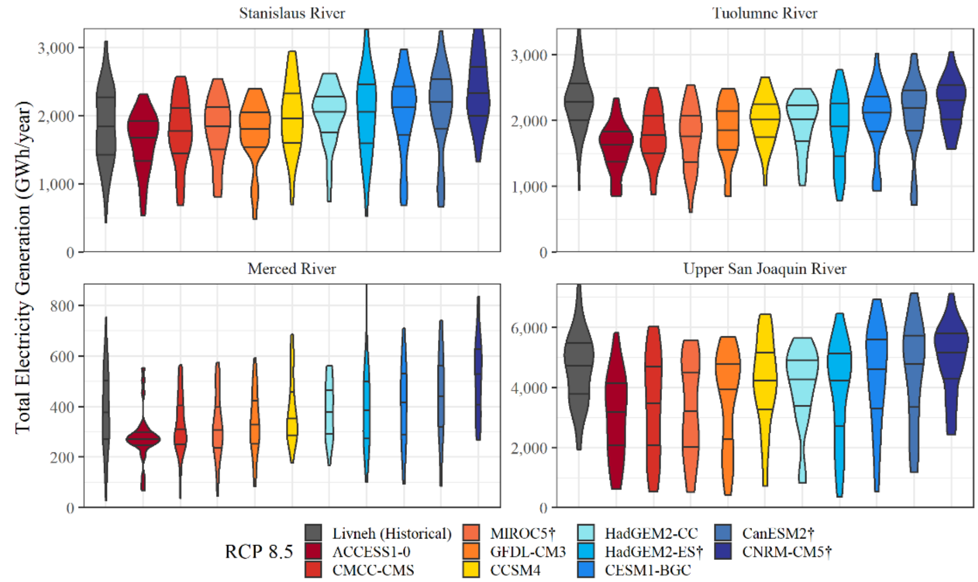
The water year types (WYT) are based on California DWR SJVI thresholds for historical (Livneh) and GCMs for RCP 4.5 (top) and RCP 8.5 (bottom). Facility- specific WYT classification may vary due to alternative algorithms used in individual licenses.

Figure 16: Distribution Density of Full Natural Flow and Energy Generation for Basins and GCM (RCP 8.5) Compared to Historical



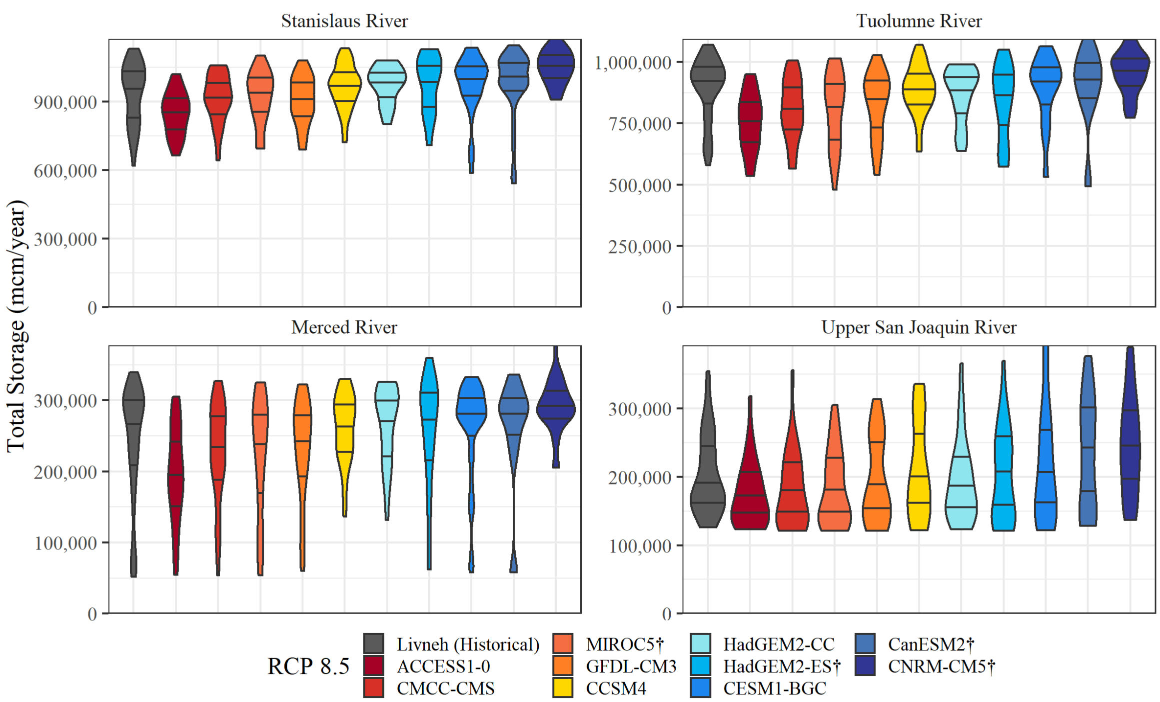
Dashed lines indicate date of centroid for each climate scenario.

Figure 17: Total Annual Hydropower Energy per Basin for Historical (Livneh) and Near Future GCM (2031-2060) RCP 8.5



Note: different vertical scales.

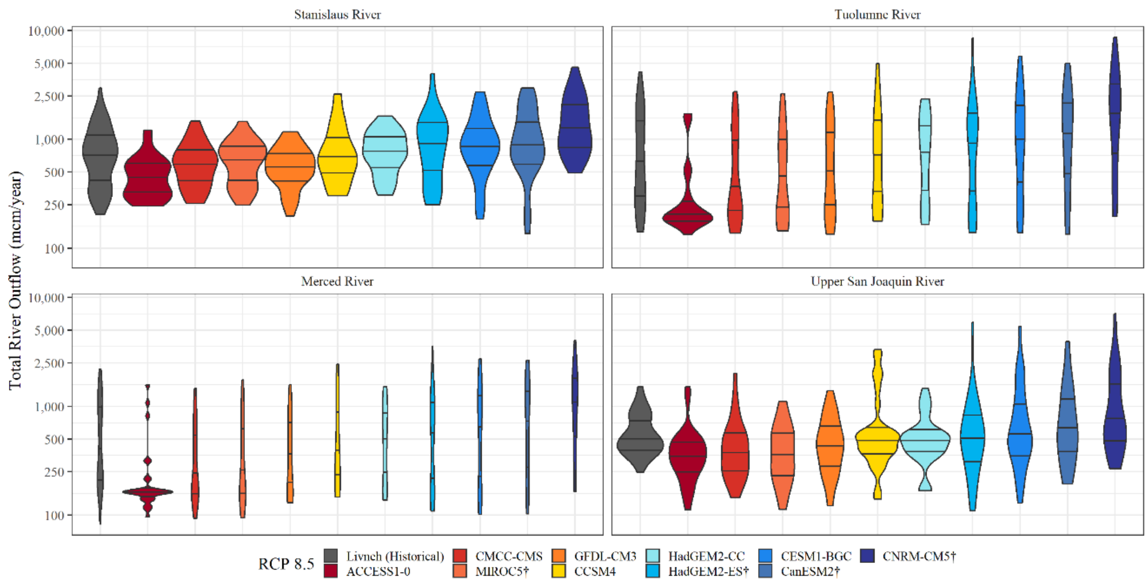
Figure 18: Total Annual Reservoir Storage for Historical (Livneh) and Near Future GCM (2031-2060) RCP 8.5



Note: different vertical scales.

The greatest impact is seen in basin outflow, where overall system impacts range from -50 percent to 105 percent compared to historical data (Figure 19). Although operational objectives influenced the balance between storage of water and use of water for hydropower generation, the basin's cumulative shortfalls in runoff were most acute at the final outflow. The decrease in outflow was smallest in the Stanislaus, where the driest projections only resulted in -41 percent total annual outflow but the wettest produced more than 91 percent increase. Conversely, the worst impacts were seen in the Tuolumne, where outflow ranged from –62 percent to 129 percent compared to historical figures.

Figure 19: Total Annual Outflow per Basin for Historical (Livneh) and Near Future GCM (2031-2060) RCP 8.5



Note: different vertical scales.

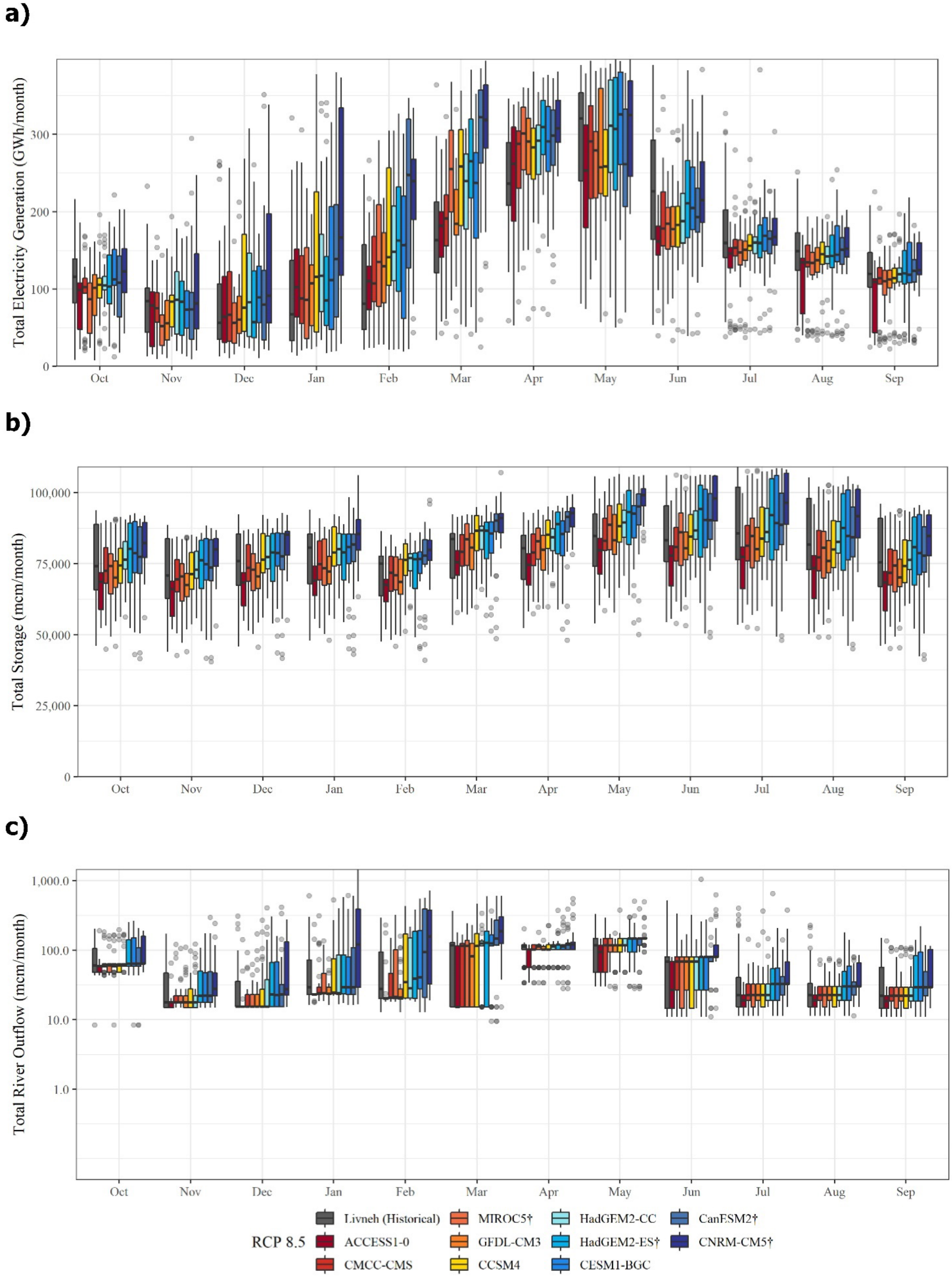
As a comparative "hydropower-only" case, the IFR constraint on basin operations were removed to investigate the potential energy generation without instream environmental regulations. The energy produced by all basins was minimally impacted. Removal of IFR constraints in the basins slightly increased annual hydropower generation for all scenarios but did not substantively alter the range and pattern of climate impacts. Operations produced similar results to the overall baseline.

Basin-Specific Impacts

Stanislaus Basin

The Stanislaus is a hydropower optimized system with a large reservoir system similar in size to the Tuolumne. New Melones and Tulloch reservoirs account for about 86 percent of the total storage and the large capacity of the two reservoirs buffered the shift in future scenarios. The operations of facilities in the basin exhibited small changes in hydropower production due to a shift in timing and volume in the early spring (Figure 20).

Figure 20: Stanislaus River Basin Monthly Production, Storage and Outflow



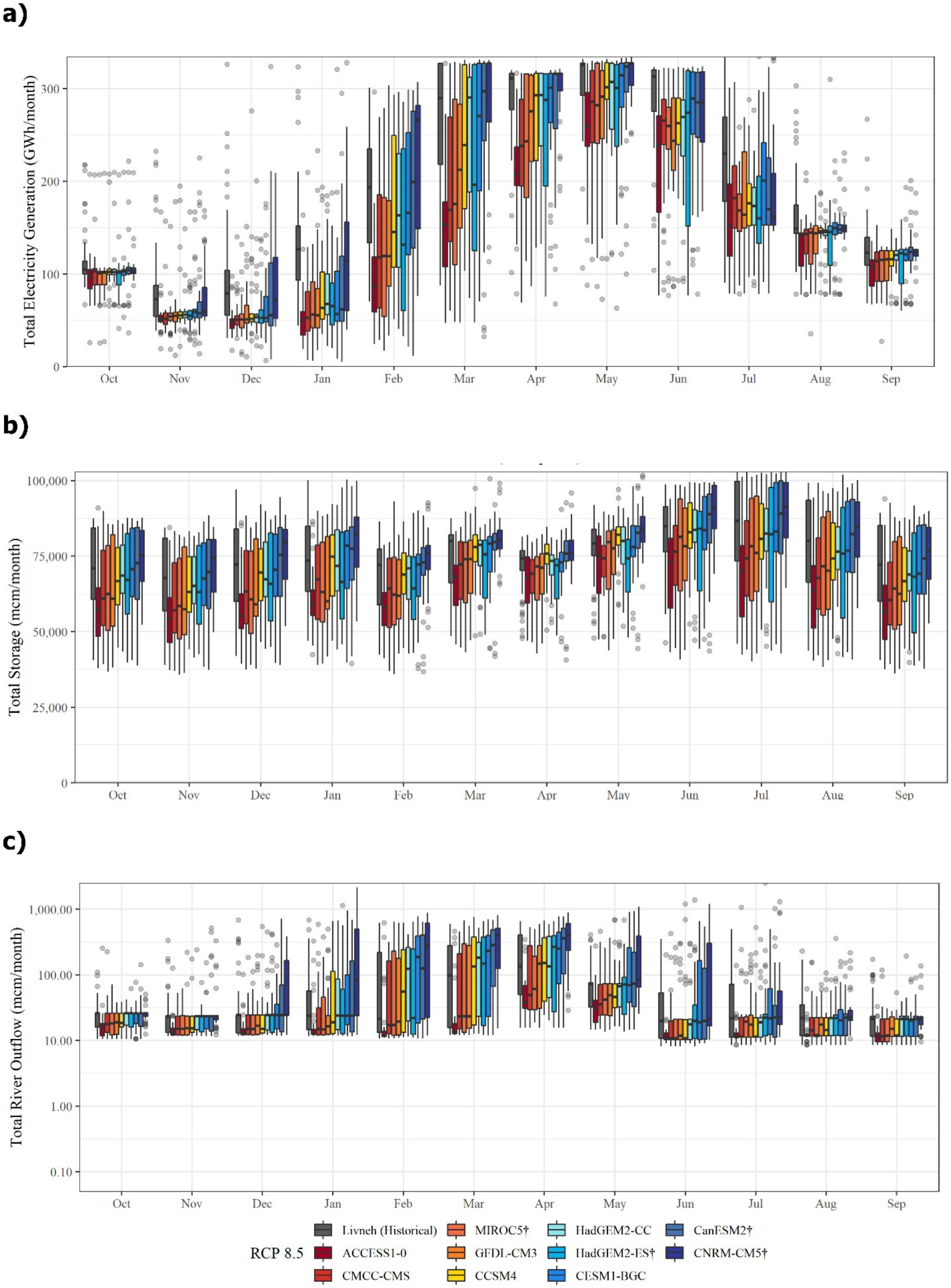
Total monthly (a) Hydropower production (GWh) and (b) reservoir storage (mcm) and (c) basin outflow (mcm log10) for historical and near future GCM (2031-2060) RCP 8.5.

Overall production increased earlier in the season with the shift in flow timing. Greatest negative impacts on energy production were between June - October, even in wetter scenarios. Although future dry conditions had negative impacts on production (as much as -30 percent), the wettest scenarios showed increases of 80 percent to 117 percent in energy production between January and March. The basin experienced minor impact to storage (-9 percent to 12 percent) but also had the best outcomes (-9 percent to 29 percent). The large shifts in centroid timing of flow, were not reflected in the centroid timing of electrical production, likely due to the optimization between reservoir storage and the release to turbines. The Stanislaus basin's mean annual outflow was also the least impacted in the study area, however, the wettest projections indicated possible outflows up to 91% of historical figures. Occurrences of low storage are exhibited in CESM1-BGC and CanESM2, and rarely in other scenarios. Conversely, other wetter GCMs exhibit occurrences of uncontrolled spill with very rare other scenarios (Figure 21). Even with shifts in total annual water supply, New Melones rim reservoir rarely dropped below 1/3 capacity (Figure 25). Additional diversion, such as agricultural deliveries, may reduce this direct outflow from the rim dams. Future work improving estimates of deliveries would improve model accuracy.

Tuolumne Basin

Facilities in the Tuolumne basin are operated primarily for water deliveries with hydropower produced opportunistically. The system contains large reservoirs similar in storage to the Stanislaus. With similar mean annual storage, the impacts of future projections on storage in the Tuolumne were like those of the Stanislaus, however, the lack of hydropower-optimized operations resulted in decreases in total energy production (-31 percent to -1.4 percent) even in the wettest future scenarios. The largest relative drops in monthly energy production occurred between November and March, however, the most significant absolute losses occurred from May to July (Figure 21). Outflows from the Tuolumne were most acutely impacted by dry projections, with decreases in the mean annual outflow by as much as 62 percent, with the worst deficits seen between April and September (Figure 21c). On average, higher runoff in the basin produced a greater number of high flow outliers in basin outflow and hydropower production, particularly from August to November. Uncontrolled spills increase as the GCMs increase in wetness, moving from 0 to 342 (Figure 24). Typically, the number of IFR deficits are low, however, all but the wettest GCM increased this metric between 12 percent to 119 percent, with the exception of CCSM4 and CNRM-CM5 (Figure 26). All other basins decreased in IFR deficits. Historically, the number of events of low storage only occurred in MIROC5 and HadGEM2-ES at 62 and 91 in the time series, respectively (Figure 26). The variability in the red flag metrics indicates a shift in fundamental runoff timing in this basin. However, water deliveries and transfer in the Tuolumne basin are not well understood and missing key information regarding demand and drought curtailments, leading to greater uncertainty regarding the fate of outflows/withdrawals from the system. Future work should address these data gaps to improve model performance.

Figure 21: Tuolumne River Basin Monthly Production, Storage and Outflow



Total monthly (a) hydropower production (GWh) and (b) reservoir storage (mcm) and (c) basin outflow (mcm log10) for historical and near future GCM (2031-2060) RCP 8.5.

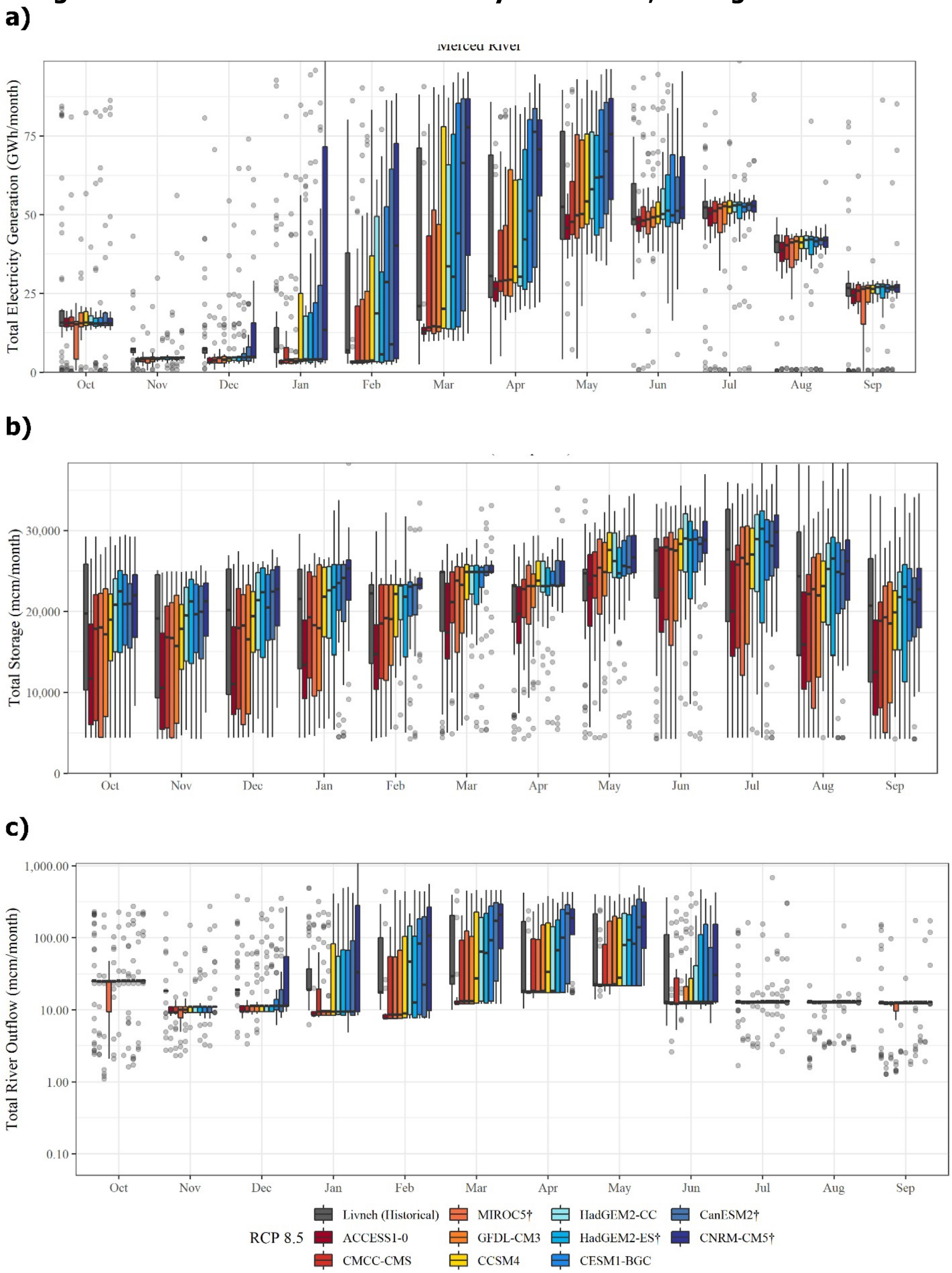
Merced Basin

The Merced basin has a limited number of hydropower facilities, and those facilities are not operated to optimize energy production. Storage is on average equivalent to 25 percent of the Stanislaus or Tuolumne with energy production an order of magnitude smaller than the other basins. Generation at the basin's facilities showed a shift to energy production earlier in the season with wetter projections and later in drier projections (Figure 22). Overall, the basin experienced a much wider range of perturbation than other basins, with storage ranging from –18 percent to 20 percent and energy from –28 percent to 32 percent. The greatest perturbations (positive and negative) in energy production were between October and March, however, greatest absolute differences were seen April to August. The storage capacity and released outflow during this time also exhibited high variability depending on GCM projection (Figure 22). Although the rim reservoir historically reduces to a low capacity, future forecasts predict wetter conditions that also exhibit severe drops in the rim reservoir storage (Figure 25). The small size of this basin resulted in much greater potential variability in future outcomes.

Upper San Joaquin

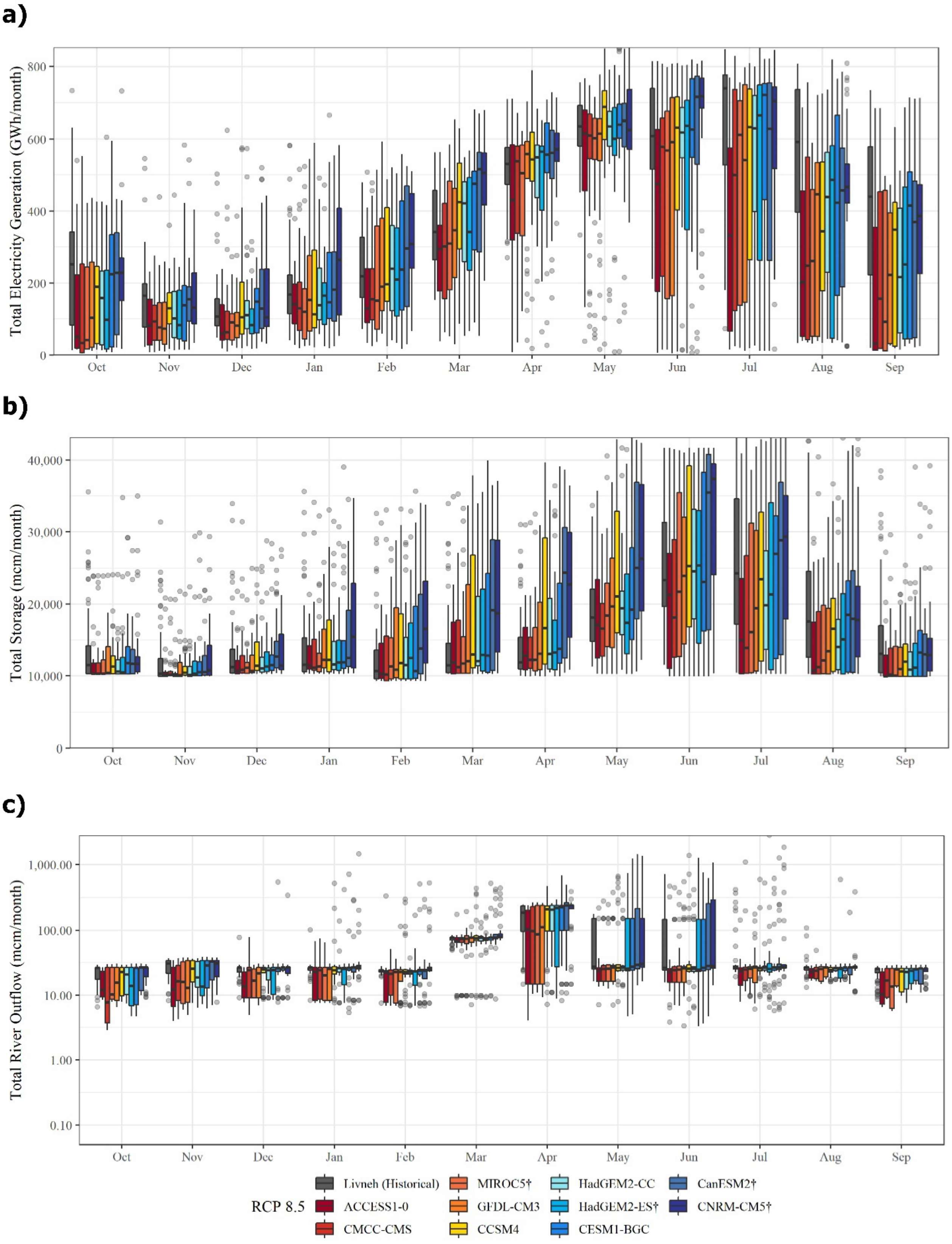
The Upper San Joaquin basin is dominated by projects operated primarily for hydropower generation and agricultural water deliveries; however, its mean annual storage is on par with the Merced basin. On average, the range of future projections were more likely to increase storage and outflow, however, the relative impact to hydropower was typically negative. Despite the basin's hydropower-optimized operations model, the lack of large storage and more frequent emptying (Figure 25), resulted in this basin's hydropower energy production being more impacted. Changes in future hydrology resulted in a range of mean annual energy production between -34 percent to 6 percent with the largest absolute drops occurring between June and November, commensurate with similar drops in basin storage (Figure 24). Conversely, in the wetter projections, the reservoir was more consistently filled (Figure 25) and occurrences of deficits in the IFRs were reduced (Figure 26), however, occurrences of uncontrolled spills greatly increased (Figure 21). Benefits from the wettest future projections were marginal despite the high range of possible future impacts from the variety of GCMs. The San Joaquin basin produces more annual average energy than all other basins combined and exhibits the greatest uncertainty of impacts of all the study's basins.

Figure 22: Merced River Basin Monthly Production, Storage and Outflow



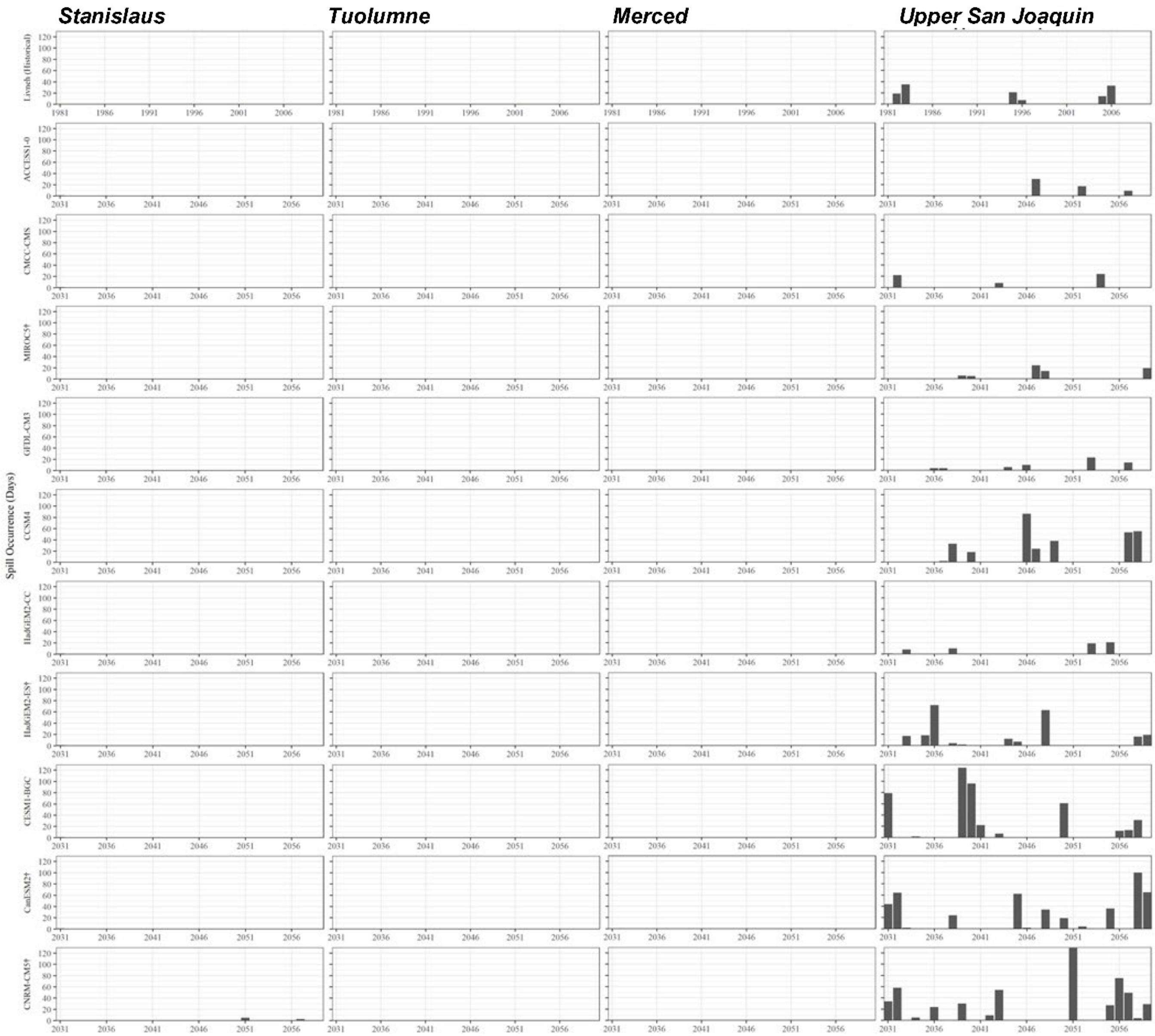
Total monthly (a) hydropower production (GWh) and (b) reservoir storage (mcm) and (c) basin outflow (mcm log10) for historical and near future GCM (2031-2060) RCP 8.5.

Figure 23: Upper San Joaquin River Basin Monthly Production, Storage and Outflow



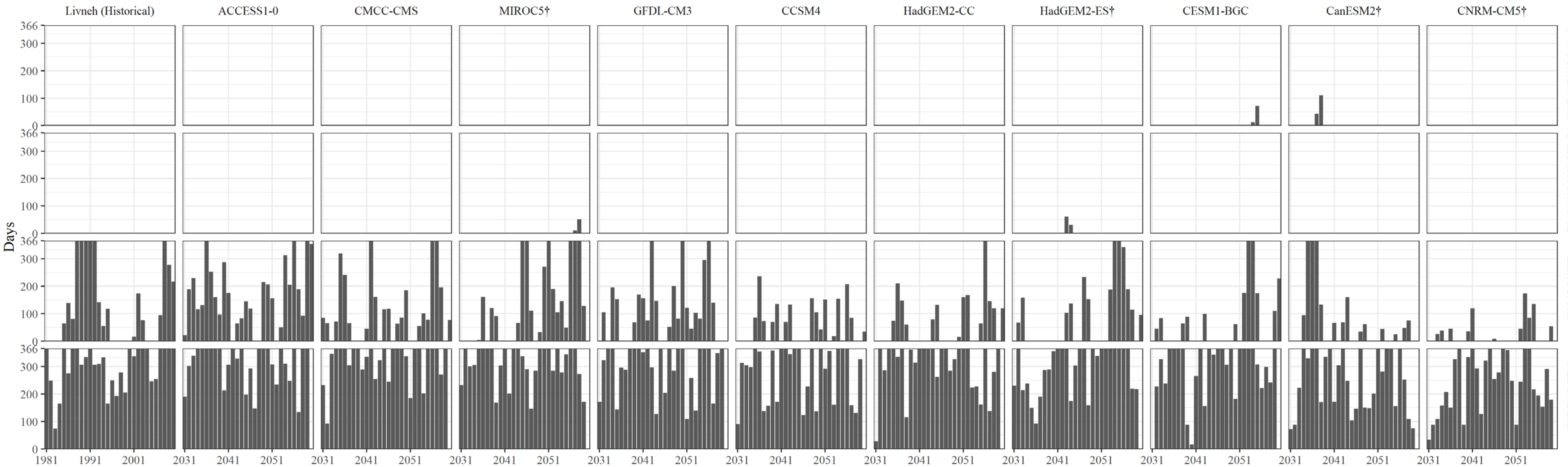
Total monthly (a) hydropower production (GWh) and (b) reservoir storage (mcm) and (c) basin outflow (mcm log10) for historical and near future GCM (2031-2060) RCP 8.5.

Figure 24: Annual Days of Rim Dam Uncontrolled Spill in Each Basin



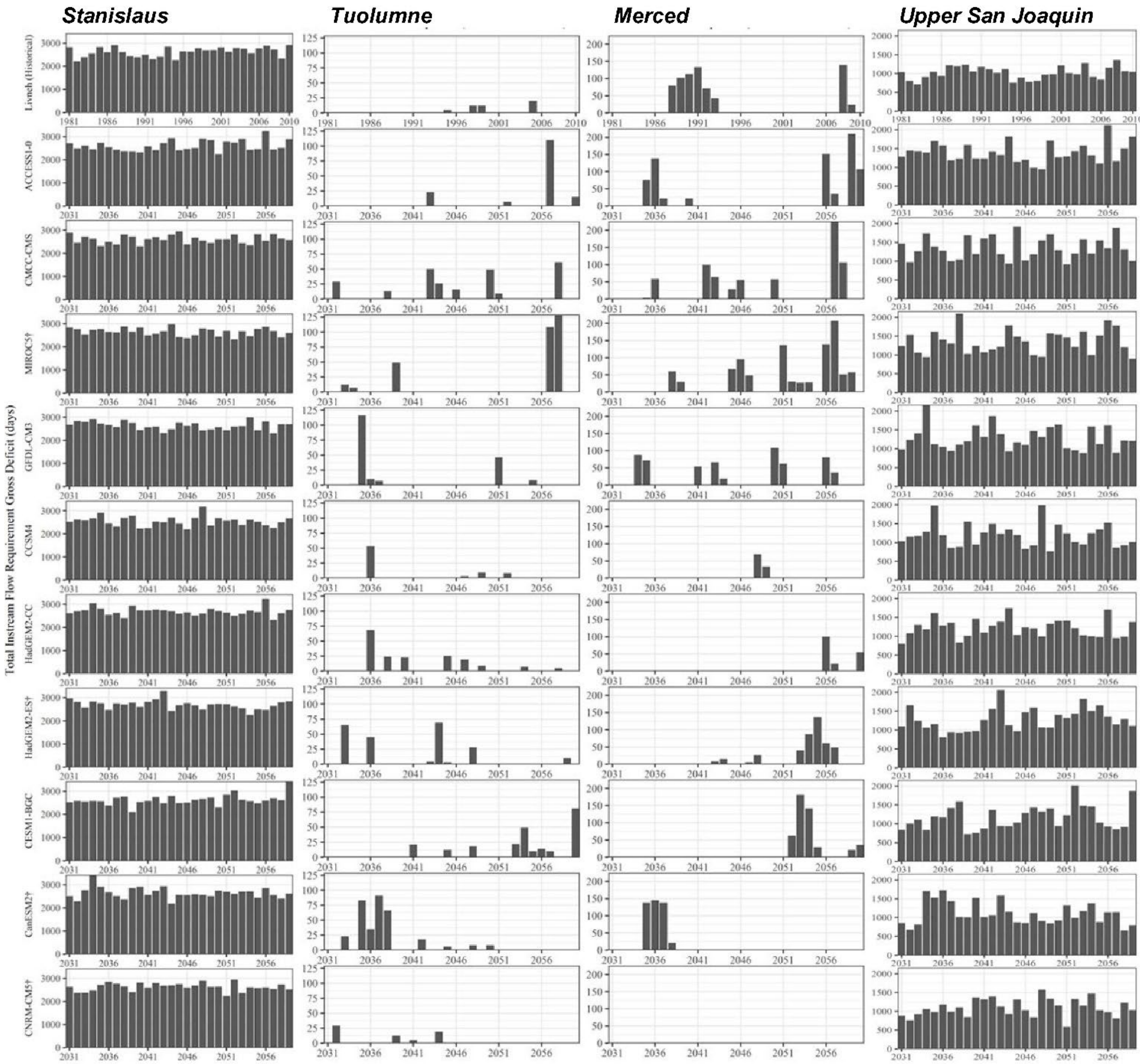
These events are indicative of excess water spill beyond flood control releases. Comparison of historical (Livneh) and near future GCMs (2031-2060) in RCP 8.5.

Figure 25: Annual Days the Rim Reservoir in Each Basin Below One-third Capacity



The operations are indicative of loss of storage due to alterations in volume and timing of reservoir inflows or due to operational requirements for downstream IFRs or deliveries. Comparison of historical (Livneh) and near future GCMs (2031-2060) for RCP 8.5. Corresponding basins (top to bottom) are Stanislaus, Tuolumne, Merced, and Upper San Joaquin.

Figure 26: Number of Annual Events of Gross Deficit IFR Requirements in All Basins



Comparison of historical (Livneh) and near future GCMs (2031-2060) for RCP 8.5. Events of deficit can occur at multiple locations in each basin.

Hydrologic Flow

Metrics calculated through IHA provided insights into the influence of climate change and regulation on ecologically impactful flows. Assessing the unimpaired flows isolated the impact of GCM projections on base hydrology, whereas IHA metrics of regulated (impaired) flows investigated the effect of basin operations on natural flows but also the variability of future climate scenarios.

Future climate impacts are expected to increase high flow pulses and low flow periods for the Stanislaus and Merced, while greatly reducing them in the Upper San Joaquin (Figure 27, Figure 28). Unimpaired basin flows exhibited fewer high pulses with longer lengths for future GCMs as compared to historical for the Stanislaus, Tuolumne, Merced, and Upper San Joaquin. The Upper San Joaquin regulated flow exhibited the greatest impact showing a large number of outliers, compared to natural unimpaired flows. Basin operations at rim dams often responded to competing dynamics in inflows and water demands or hydropower objectives. River regulation for all basins except the Tuolumne greatly increased the length of these low flow events through the impoundment of water in the rim dams.

Figure 27: High Flow Pulses for Historical Hydrology and GCMs (RCP 8.5)

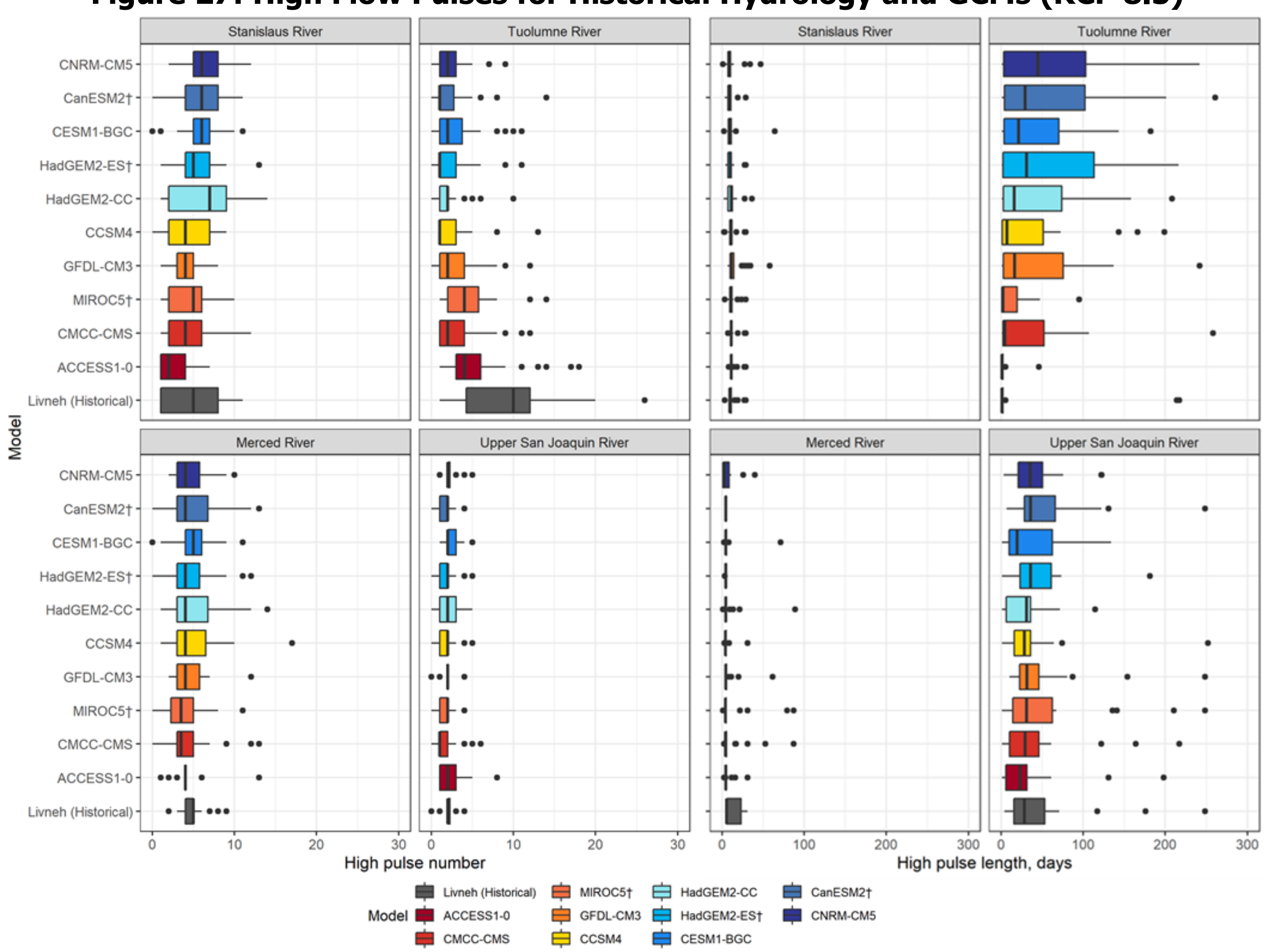
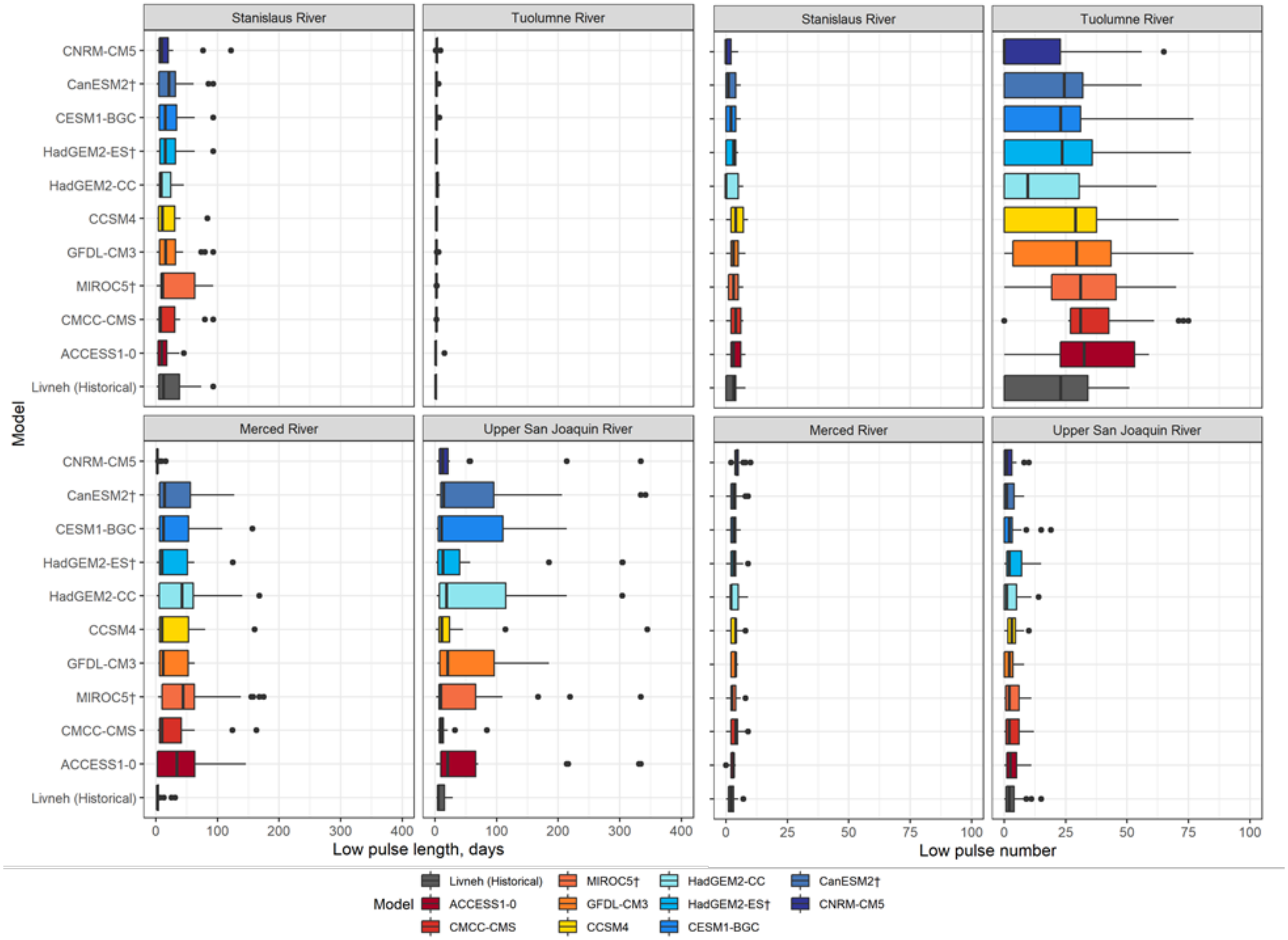


Figure 28: Low Flow Pulses for Historical Hydrology and GCMs (RCP 8.5)



Discussion

Model Development

Multiple improvements have been made to previous efforts, as presented in prior CEC funded research (Rheinheimer et al. 2014; Rheinheimer, Ligare, and Viers 2012; Yarnell et al. 2013; Rheinheimer and Viers 2015; Rheinheimer, Yarnell, and Viers 2013). Compared to previous efforts, this study also includes a higher spatial resolution (1/16°) and finer temporal resolution (daily) timeseries of hydroclimatic data across a large spatial domain (four regional river basins feeding the San Joaquin River).

The model is versatile enough to include hydroeconomics-driven quasi-optimal hydropower and includes two operational modes, a monthly timestep planning mode for estimating optimal monthly hydropower generation and a daily timestep scheduling mode for allocating water using more detailed rules. The planning module is not necessarily needed in basins where there is little discretionary hydropower release (the Merced and Tuolumne basins), which results in significantly faster run times. Though not elaborated further here, the Stanislaus and Upper San Joaquin basins resulted in very poor model performance metrics when run in scheduling-only mode (without optimization). The temporal and spatial domains can also be constrained as needed, although each basin runs independently. The use of the python-based Pywr package represents a significant improvement over previous efforts, in several ways.

First, in contrast to WEAP's limited ability to incorporate hydroeconomic principles without significant extension, *Pywr* natively allows for the inclusion of piecewise linear cost functions, thus enabling the development of the price-based hydropower optimization approach used in this study. Although *Pywr* is not intended to be used as an imperfect foresight multi-timestep optimization model, its Python-based, object-oriented nature allowed this development. Beyond hydropower optimization, the piecewise linear functionality allows the inclusion of more sophisticated—and ecologically meaningful—instream flow requirements, however, this was not explored in this study.

Second, *Pywr* is open source, which allows transparency in the modeling process and source code modification. Pywr is designed to be highly customizable in a way that can also be computationally fast with programming expertise. With such code optimization, Pywr can run fast enough for many-scenario exploratory studies. Finally, the modeling approach used enables the inclusion of more detailed IFRs compared to Rheinheimer et al. (2014) in an open source all-Python environment. The inclusion of minimum and maximum IFRs allows observation of more realistic environmental flows, such as those being developed by the California Environmental Flows Framework.[14] As our understanding of California stream requirements improve (Yarnell et al. 2015; Yarnell, Viers, and Mount 2010), and the concept of more complex instream flow requirements (which includes seasonal variability) become mainstream, models such as those developed in this study will be increasingly necessary and useful to explore tradeoffs between instream flow requirements and other human demands. The incorporation of ramping rates as IFR constraints makes the model a useful tool to study the flexibility limitations of hydropower systems within California's changing energy grid operations.

Though the model builds on previous work, the fine spatiotemporal scales did pose challenges. First, the finer spatial resolution does not necessarily translate to a more accurate hydrologic model, in part because of basin outlet bias correction, and also due to sub-basin bias correction limited to observed data. Imperfect hydrology, particularly at the sub-basin scale, impacts the outcome of any operational logic. Secondly, the model's daily timestep does not necessarily impart a more accurate operations model, in part because hydropower operations are optimized with monthly calculations and foresight. Additionally, some hydropower facilities and reservoirs, provide sub-daily services, such as ancillary energy services or recreational water releases. Not all of these sub-daily releases are codified in operational manuals and discrepancies between the simulated and observed data can be

[14] California Environmental Flow Framework 7

impacted by these operations. Energy prices as predicted by HiGRID are also generalized, omitting some of the ancillary services. Previously, Mehta et al. (2011) and Rheinheimer et al. (2014; 2012) used a statistical regression approach to hydropower operations using the WEAP modeling framework, this study explicitly included variable regional wholesale electricity pricing in discretionary hydropower operations. However, any error in this pricing will impact the results of the optimization. Although 2009 prices generally reflect approximate modern energy demand, the use of prices from a single year further limits the ability to model historical operations accurately.

The historical modeling accuracy can be improved by integrating hydrology and water/energy demand models, which would be of great value to public research and utilities. Participants in discussions with the project TAC expressed a need for a reconstructed historical hydrologic dataset.

Water demand used in this study was limited by observed data, such as agricultural water deliveries or urban water demand. Additionally, future conditions were based on a baseline of 2019 water demand and timing. Urban population growth, changes in crop and land management, and aquifer recharging in the region will significantly impact the expected demand for water from reservoirs. Investments in modeling potential demand would improve the model outcomes for future climate change assessment, particularly for basins operated primarily for water supply.

Although the model was built to incorporate daily energy pricing inputs from external models, assumptions in those models impact the optimization of hydropower operations. Energy prices were used to define the relative value (negative cost) of water for hydropower generation at the hydropower facilities. The energy price data from the HiGRID energy model for future energy grid scenarios showed decreasing prices in the future due to increasing contribution from solar and wind. The HiGRID model shows more negative prices by mid-century.

Based on TAC meeting discussions, such scenarios may not be realistic, given that there are many other factors that impact prices, such that the market would correct itself. The trends in energy pricing (and future energy scenarios) need further scrutiny. Nevertheless, there will be some negative pricing which requires a better understanding of individual hydropower facilities such as: the limitations and constraints in starting/stopping a facility; the value of ancillary services; the downstream minimum flow or ramping rate requirements; and the infrastructure capacity to bypass turbines. Further research, including a better understanding of the system, is required to include negative energy pricing. Future energy pricing is difficult to predict due to political-economic landscape changes. The development of energy price scenarios could be useful to better understand the impacts of a broader range of potential future political-economic conditions.

Impact of Climate Change on Hydropower

The hydropower system modeling framework described in this report builds on previous regional modeling efforts by Rheinheimer et al. (2014). Three of the ten GCMs considered in this study show higher average annual inflows, indicating increased rainfall and spring snowmelt. Four of the ten GCMs indicated moderate to severe decreases in basin runoff, impacting the timing and quantity of flow available for storage and power generation. For each GCM, the model shows increased average winter and spring inflows, leading to higher hydropower production. The inflows either increased slightly or decreased in the fall and the summer. Consequently, hydropower production often decreased during the summer while other months demonstrated higher variability. GCMs indicated an overall drier basin water trend with variable outcomes in basin operations.

Infrastructure and operational objectives were an important factor in determining the types of impacts caused by drier and wetter GCM projections. Basins with larger amounts of storage, particularly large rim reservoirs had substantially less variability in their mean annual storage, in deficits and excesses. The Stanislaus and Tuolumne basins have similar large storage capacities and the variation in storage between the driest and wettest GCMs was less than +/- 15 percent. Conversely, the Merced and the Upper San Joaquin basins with similarly small storage capacities experienced the greatest variability, however, for the latter this typically resulted in storage deficits for the majority of GCMs. Reservoirs mitigate the impacts of flow variability on energy generation as they help reduce the variance in the flows available for the hydropower facilities through carryover storage. Large storage capacities also mitigate negative impacts from deficits and excesses in water supply – reducing low capacity in reservoirs as well as uncontrolled spills.

The results from this study are consistent with some of the outcomes from Rheinheimer et al. (2014). The study estimated a small increase (~2 to 4 percent) in hydropower production for 2°C, and 4°C temperature increase scenarios for the Stanislaus, Tuolumne, and Upper San Joaquin basins and a small decrease or no change for 6°C scenarios. Rheinheimer et al. (2014) did not model the Merced basin, since Lake McClure was outside of their scope and flows upstream are unimpaired. In our study, these estimates hold true in the Stanislaus basin for moderate GCMs (such as CCSM4, HadGEM2-CC, HadGEM2-ES), however, the Tuolumne and Upper San Joaquin basins were impacted negatively by the majority of dry to moderate GCMs. Only in highly wet projections was energy production equal to or above historical averages. GCM scenarios cannot be directly compared with uniform temperature increase scenarios as some of the GCMs used model a combination of precipitation and temperature ranges. However, the impact of infrastructure in relation to runoff in the Central Sierra Nevada was key to develop a model with a daily timestep and more granular operational logic.

Impact of Climate Change on Ecosystem Objectives

Although reservoir storage has moderated some impacts to hydropower energy production in optimized basins, the resulting outflows from the basins have shown the downstream impact of conservative upstream operations. With future climate projections, the resulting variability in outflow exhibited large deficits and excesses. Four of the ten GCMs (from driest to moderate) decreased their annual outflows by 23 percent to 50 percent for nearly all basin scenarios. Decrease in outflows, coupled with longer low pulse length in basins such as the Stanislaus and Merced, indicated changes in upstream water impoundment and conservation in reservoirs. Conversely, the extreme outflows were similarly high for the wettest projection (CNRM-CM5) which also impacted the downstream environments and communities. Increased number of high pulses in wetter future scenarios indicate that there may be more frequent extreme releases from rim reservoirs. The Upper San Joaquin basin exhibited very high variability in operational outcomes and IHA metrics, potentially indicating a more challenging operational environment for a key tributary of the San Joaquin River.

Although many of the facilities currently implement a combination of FERC-licensed IFRs and some additional environmental releases, increased regulation in environmental flow management is likely as operations are relicensed and new regional strategies are implemented (such as the San Joaquin

River Restoration Program and the Delta Plan). New approaches to environmental flows, such as functional flows (see Chapter 3), increase uncertainty to future hydropower energy planning. Modeling with environmental flow management can provide additional insights into potential opportunities and challenges.

CHAPTER 3: Assessing Hydropower Constraints

Introduction

Hydropower is an important aspect of California's energy production. While climate change is an important consideration for future hydropower production, recent policy changes in California point to a more immediate potential constraint. Environmental stream flow has long been studied, though historically California has recognized little authority to define or enforce environmental flows over other water uses. Recently, the State Water Resources Control Board (SWRCB) affirmed their authority to set and enforce environmental flows throughout the state.

In the *2018 Supplemental Environmental Projects Report* (CA EPA 2018), the SWRCB made a specific prescription for environmental flows in the Stanislaus, Tuolumne, and Merced basins of the San Joaquin watershed. The Board recommended that 30 percent to 50 percent of the full natural flow regime be released from February through June to support fish populations in the main stem of the San Joaquin River. When the effects of this environmental flow policy on hydropower were assessed, the SEP report found little impact on hydropower generation and transmission. However, it was unclear how the trade-offs between environmental flows and hydropower production differed over a variety of WYTs, or if the approach affected other aspects of basin operations like flood control or water supply.

In addition to the broad interpretation of how the prescribed environmental flow policy might affect hydropower, the underlying premise of the environmental flow prescription may not be the most effective approach to support ecosystems. Studies have shown that having minimum flow conditions alone are insufficient for aquatic ecosystem health (Yarnell et al. 2015, 2020). Other flow characteristics, such as spring runoff, floods, transition flows etc., that mimic natural river flows are critical for different biota's life cycle stages (Yarnell, Viers, and Mount 2010). Mimicking natural flows provides for rivers that are highly managed and cannot be restored to their natural conditions, critical functions (biotic and abiotic) along its course which enable healthy ecosystems. Based on the concepts of "functional flows" (Yarnell et al. 2015, 2020), the State Board is supporting the development of a state-wide framework – different from the full natural flow framework in the SEP – to define flows for different segments of all rivers in California (CEFWG 2020).

Given the importance of hydropower to California's energy portfolio and the need to evaluate the effects of near-term policy decisions, this research included case study evaluations of alternative environmental flow scenarios. The researchers developed more operationally relevant outcomes using the CenSierraPywr framework to investigate alternative flow management approaches. Specifically, the effects of a functional flow prescription were explored on basin operations including hydropower, flood control, and water supply, then those results were compared to the SWRBs prescribed flow regime and the baseline operations (Livneh, 2009 prices) during the historical period from 1952-2013. The results of this study will provide valuable insight to the outcomes of environmental flow policy currently being implemented or considered for the three major tributaries to the San Joaquin River.

Methods

Using functional flows is a two-step process. First, functional flow needs are developed from historical unimpaired hydrology for each of the four study basins: Merced, Tuolumne, Stanislaus, and Upper San Joaquin. For this study, Dr. Sarah Yarnell collaborated with the team to define a functional flow regime for each basin. Dr. Yarnell was a member of the TAC for this project and also sits on the technical team of the Environmental Flows Workgroup of the California Water Quality Monitoring Council that is developing the California Environmental Flows Framework,[15] which uses the functional flows concept to prescribe ecological flows for every stream in California. With support from Dr. Yarnellthe team developed a functional flow schedule for each basin using a tool that recommends a range of flow rates and timing for ecologically relevant, hydrologic components, including:

- Fall pulse flow
- Wet-season peak and base flows
- Spring recession flow
- Dry season base flow

Each component is broken down into a suite of specific, quantified metrics (Table 6) using an R-based, open-source functional flow calculator that uses a long-term data set (>10 consecutive water years of daily data). Annual functional flow metrics were calculated for the four basins using the historical Livneh full natural flow (FNF) data. Then, the results were analyzed to develop a functional flow schedule based on hydrologic year type for each basin. To remain consistent with other applications of the functional flow approach, hydrologic year type was defined using a tercile analysis to establish "dry," "moderate," and "wet" year types based on the distribution of total annual flow. The annual functional flow results for each year of the Livneh record were sorted according to year type; then, they were analyzed to determine the 10th, 25th, 50th, 75th, and 90th percentile values for each metric. For this study, the functional flow schedule was defined as the 50th percentile value for each metric.

The magnitude of the wet season base flow was the one exception to the 50th percentile value approach. On-going research has shown that the functional flow tool tends to over-estimate the 50th percentile magnitude of wet season base flow in watersheds where the unimpaired hydrology is dominated by winter storm runoff. For this reason, wet season base flow in the four study basins was defined by the 10th percentile value. However, wet season base flows tended to increase to the 50th percentile magnitude following peak runoff events that occurred after February 1. The model logic was written to increase the wet season base flow from the 10th percentile to the 50th percentile following peak flow events that met or exceeded the 2-year event magnitude after February 1. At the end of the classification process, each basin had a daily flow prescription that replicated ecologically functional flows below the rim dam, which varied by year type (Figure 29).

Table 6: Functional Flow Metrics Associated with the Five Natural Functional Flow

[15] https://ceff.ucdavis.edu

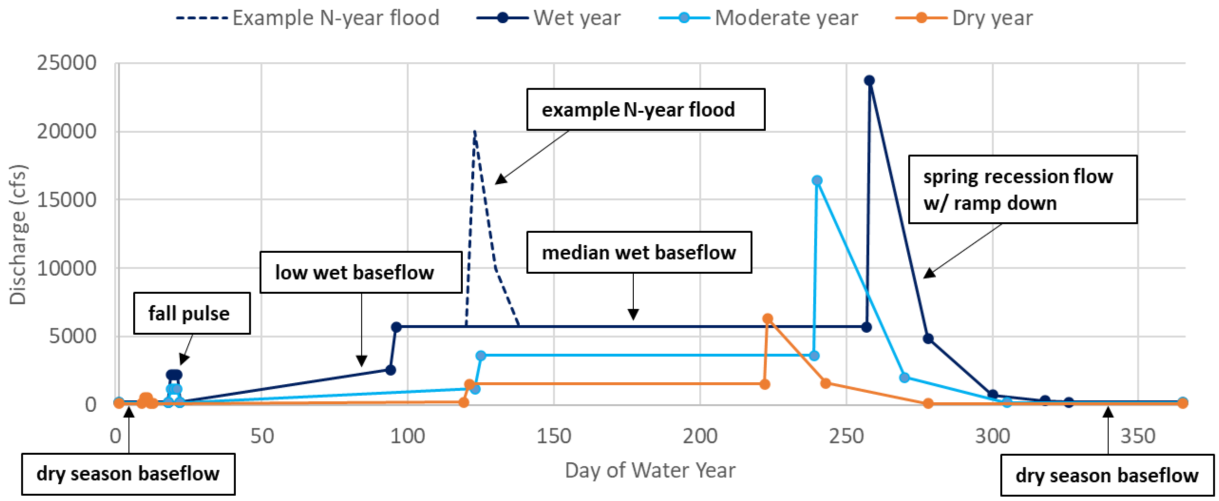
Components

Functional Flow Component	Flow Characteristic	Functional Flow Metric
Fall pulse flow	Magnitude (cfs)	Peak magnitude of fall season pulse event (maximum daily peak flow during event)
	Timing (date)	Start date of fall pulse event
	Duration (days)	Duration of fall pulse event (# of days start-end)
Wet-season baseflow	Magnitude (cfs)	Magnitude of wet season base flow (10th and 50th percentile of daily flows within that season, including peak flow events)
	Timing (date)	Start date of wet season
	Duration (days)	Wet season base flow duration (# of days from start of wet season to start of spring season)
Wet-season Peak flows	Magnitude (cfs)	Peak-flow magnitude (50%, 20%, and 10% exceedance values of annual peak flows over the period of record; these correspond to the 2-, 5-, and 10-year recurrence intervals, respectively)
	Duration (days)	Duration of peak flows over wet season (cumulative number of days in which a given peak-flow recurrence interval is exceeded in a year)
	Frequency	Frequency of peak flow events over wet season (number of times in which a given peak-flow recurrence interval is exceeded in a year)
Spring recession flow	Magnitude (cfs)	Spring peak magnitude (daily flow on start date of spring recession-flow period)
	Timing (date)	Start date of spring recession (date)
	Duration (days)	Spring flow recession duration (# of days from start of spring to start of summer base flow period)
	Rate of change (%)	Spring flow recession rate (Percent decrease per day over spring recession period)
Dry-season baseflow	Magnitude (cfs)	Dry season base flow magnitude (50th and 90th percentile of daily flow within summer season)
	Timing (date)	Dry season start timing (start date of summer)
	Duration (days)	Dry season base flow duration (# of days from start of summer to start of wet season)

Functional flow metrics describe the magnitude, timing, duration, frequency and/or rate of change of flow for each of the functional flow components.

Source: modified from CEFWG (2020).

Figure 29: Functional Flow Template Definition Points for the Tuolumne River



Measured and modeled at La Grange Stream Gauge (USGS 11289650).

Source: US Geological Survey

Using the functional flow schedules, the CenSierraPywr was adapted to prioritize functional flow releases from each of the four rim dams. This entailed the development of WY date-based rules to translate the conceptual rules outlined above to date-specific requirements. Three assumptions were used to define the CenSierraPywr logic for the templates: *a priori* WYT, selection of high-flow runoff events, and priority of management objectives.

First, since the objective was to assess the effect of a full year of functional flow releases on hydropower production and other basin operations, the WYT was defined on October 1 assuming a perfect forecast of the water year. This perfect forecasting assumption was critical to evaluating the trade-offs of a functional flow regime with hydropower production. Releases during the first months of a WY would likely be lower than those required during wet years, which are generally months after the water year starts. By releasing functional flows as though the WYT was known *a priori*, the maximum trade-off with hydropower could be quantified. Future work might consider alternative approaches that reflect the uncertainty of early season forecasting.

Next, logic was developed to determine whether wet season base or peak flows should be released. The functional flows approach identified peak flows with ecological significance similar to those with at least a 2-year return frequency. At the start of the wet season period (defined by the functional flow metric for the start day of the wet season), CenSierraPywr looked ahead for a one-day forecast of the peak flow. If the peak flow for that day met or exceeded the median functional flow magnitude for 2-year peak flows, then the event was released through the dam with no alteration. For peak flows below the 2-year event, a second decision was made regarding the base flow magnitude. If the flow entering the reservoir was below the 10th percentile wet season base flow, it was released through the reservoir with no storage. If the flow entering the reservoir was at or greater than the 10th percentile wet season baseflow, it was released. As previously mentioned, if the peak event occurred after February 1, wet season baseflows were increased to the 50th percentile. Thus, a range of peak and base flows were released, providing ecologically valuable variability in flow magnitudes and frequencies.

Finally, the new functional flows were currently prioritized over other management objectives, including flood control and water supply. In this case study, functional flows represent an ideal ecological release without consideration for other existing operational objectives. For example, the release logic during the wet season may result in higher releases than are currently accommodated by downstream channel capacity or other infrastructure. However, the functional flow logic does not preclude releases required by flood control objectives; flood control objectives requiring releases above the functional flow schedule were allowed. In addition, water supply diversions (specifically irrigation districts and the Central Valley Project) must be reduced by an amount equal to the increase in downstream releases. Future analyses should identify key areas where functional flow releases conflict with system constraints, like infrastructure capacity, and how those constraints are likely to affect the overall effectiveness of released flow.

Results

Developing the functional flow schedule for the Merced, Tuolumne, Stanislaus, and Upper San Joaquin basins revealed some differences between each basin. The tercile approach to defining WYT showed that, while hydrologic conditions were generally consistent across the basins, there were variations in runoff timing. In 21 percent of historical record years analyzed, WYTs varied across basins (Table 7).

Table 7: Water Years That Differed Across the Four Basins (1952-2008)

Water year	Merced	Tuolumne	Stanislaus	Upper San Joaquin
1953	dry	moderate	moderate	moderate
1955	moderate	dry	dry	moderate
1963	wet	moderate	moderate	moderate
1966	moderate	dry	moderate	dry
1971	moderate	moderate	moderate	dry
1979	wet	moderate	moderate	wet
1984	moderate	wet	wet	moderate
1985	dry	moderate	moderate	moderate
1989	dry	moderate	moderate	dry
1991	moderate	dry	dry	moderate
2001	moderate	dry	dry	moderate
2004	moderate	moderate	moderate	dry
2008	dry	moderate	dry	moderate

WYT varied no more than one step: whereas the year types might range from dry to moderate (for example 1953) or moderate to wet (such as 1984), there were no WYT years ranging from dry to wet across the four basins. Also, the pattern of variation was inconsistent from year to year and variations were found between two adjacent terciles.

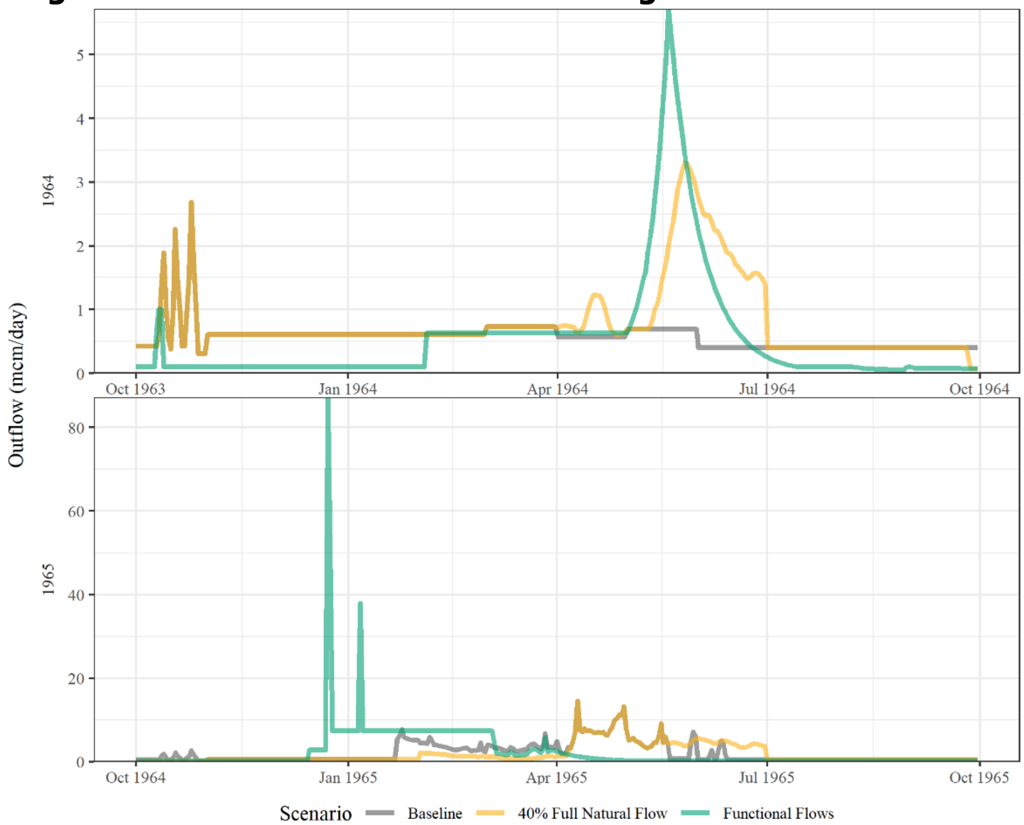
The functional flow prescription differed from baseline operations that varied depending on the WYT. For a dry year in the Merced River at Shaffer Bridge (upstream of the confluence with the San Joaquin), the functional flow scenario released lower base flows during the fall, winter, and summer, but higher peak flows and spring recession flows (Figure 30). WY impacted the releases defined by functional flows and 40 percent of full natural flows. Despite the higher peak and spring recession flows, the functional flow scenario released up to 28 percent less water during a dry year as compared to the baseline scenario, however, 40 percent full natural flow scenarios typically released up to 33 percent more water in dry years (Table 8). These changes in release were dependent on basin – during dry years some basins exhibited reductions while others had increases up to 70 percent. During a wet year, the functional flow scenario released comparable base flows to the baseline scenario for most of the water year, and higher peak and spring recession flows. As a result, total annual stream flow was generally higher in a functional flow scenario than the baseline or 40 percent of full natural flow scenarios during a wet year (Table 8).

Table 8: Total Annual Flow in the Four Basins for Three Scenarios

Basin	Scenario	Total Annual Flow (mcm)	
		Dry (1964 WY)	Wet (1965 WY)
Stanislaus River	Baseline	376.97	914.35
	Functional Flows	271.38	1,247.85
	40% Full Natural Flow	401.25	781.58
Tuolumne River	Baseline	387.99	1,299.00
	Functional Flows	661.53	2,645.13
	40% Full Natural Flow	521.55	1,282.96
Merced River	Baseline	210.55	739.57
	Functional Flows	195.67	854.45
	40% Full Natural Flow	294.38	658.79
Upper San Joaquin River	Baseline	391.18	551.05
	Functional Flows	383.47	1,234.06
	40% Full Natural Flow	589.96	952.05

Three scenarios (baseline, functional flow, and 40% full natural flow) and two WYTs: dry (1964 WY) and wet (1965 WY).

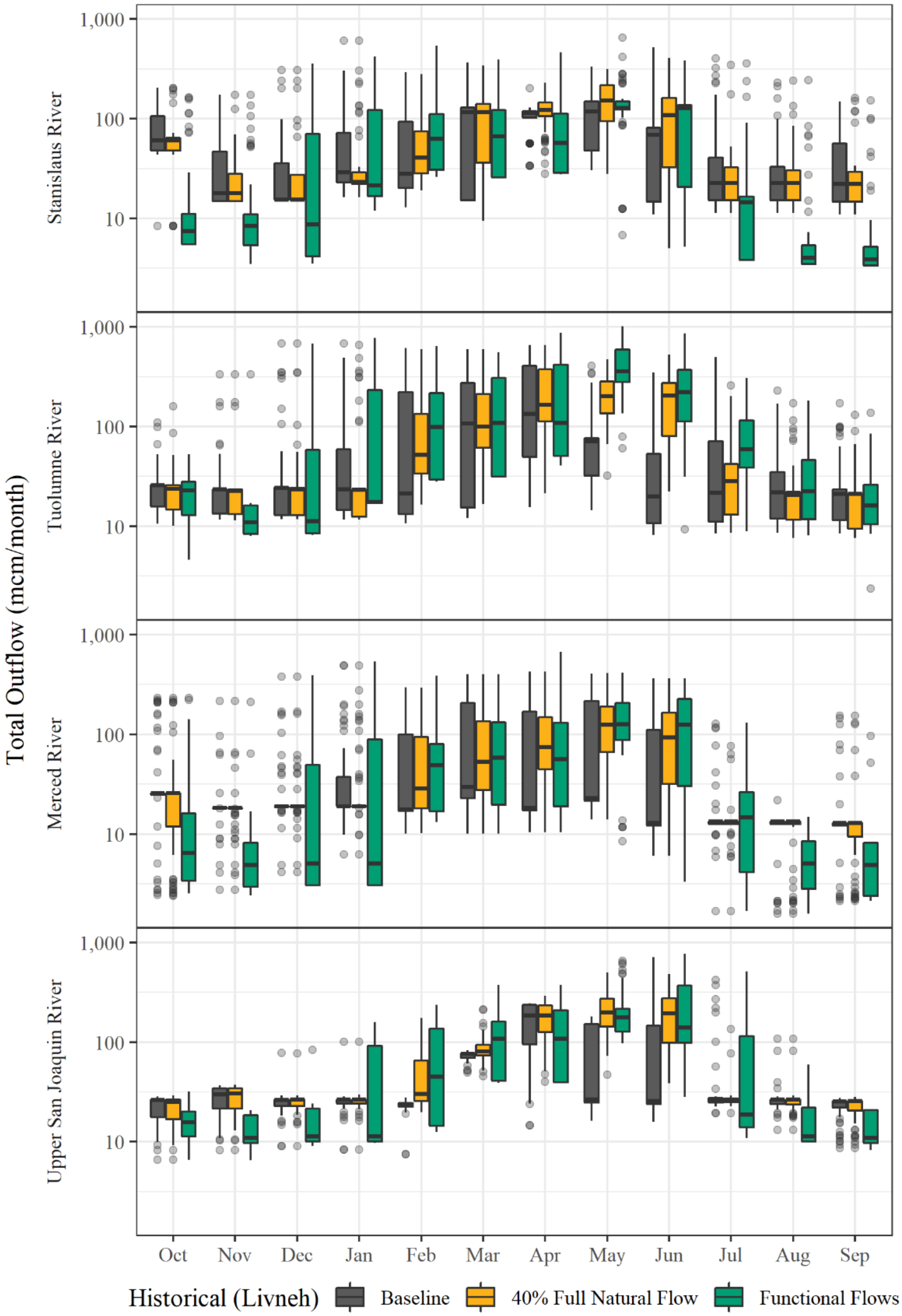
Figure 30: Stream Flow at Shaffer Bridge on the Merced River



Shaffer Bridge is located upstream of the confluence with the San Joaquin. Functional flow releases are compared to baseline (historic) operations and the full natural flow for top: the 1964 water year (Oct 1, 1963 through Sep 30, 1964), a dry year; and bottom: the 1965 water year (Oct 1, 1964 through Sep 30, 1965), a wet year.

When analyzed over the entire simulation period, outflows from each of the four basins show important differences between baseline, 40 percent full natural flow, and functional flow scenarios. Functional flows produce greater variability in almost all months for all basins. The differences are especially notable from July through January, a period generally characterized by dry season base flows. The Merced River illustrates this difference particularly well: baseline and 40 percent full natural flow scenarios show almost consistent flow from July through December with a slightly wider range of flows in January (Figure 31). In contrast, the functional flow scenario shows a more variable flow. However, while the overall variability is greater, there is a decrease in total outflow during the dry season baseflow period when compared to baseline and 40 percent full natural flow scenarios. Periods when the median flows of the functional flow scenario are generally higher than the baseline scenario are during February, when larger wet season high flow events are more frequent, and May and June, when the spring recession is released. Causes of this variability could be the addition of fall pulse flows, the passing of early season peak flow events that meet or exceed the 2-year recurrence event, or the decision to pass inflows below the 10th percentile wet season base flow without alteration. The Tuolumne is the one exception to the higher functional flow pattern in February, though it is unclear what the cause may be.

Figure 31: Total Outflow from Four Basins



Three scenarios: baseline, 40% full natural flow, and functional flows.

When stream flow releases were prioritized for ecological objectives, hydropower production decreased negligibly. More hydropower was produced with a 40 percent full natural flow scenario than a functional flow scenario. For the Stanislaus and the Tuolumne, these differences were <6 percent for both flow alteration scenarios. In the Merced basin, functional flows resulted in 14 percent less hydropower as compared to the baseline scenario and 12 percent less than the 40 percent full natural flow scenario (Table 9). In the San Joaquin River, flow alterations resulted in < 1 percent difference in hydropower generation.

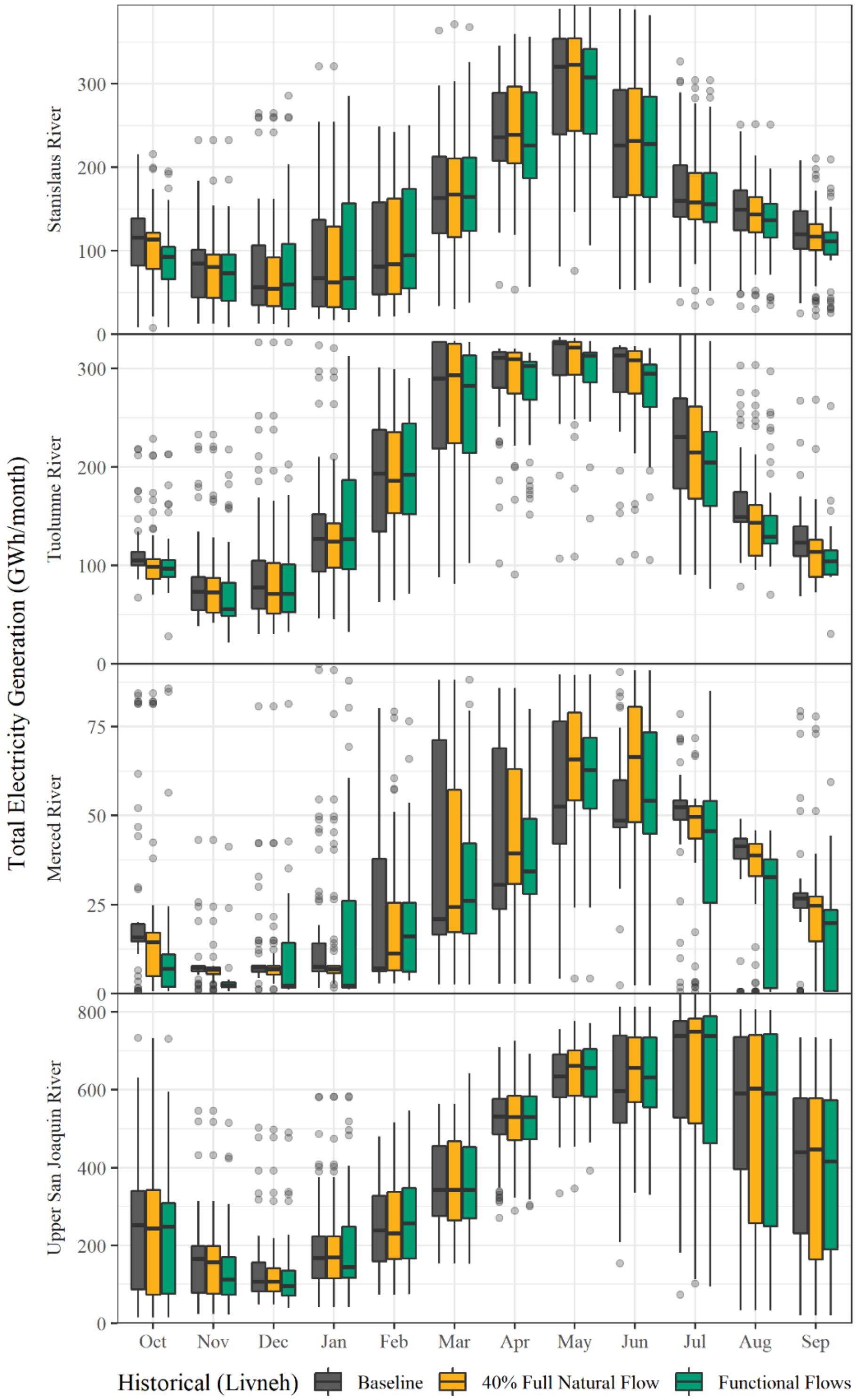
Table 9. Total Annual Hydropower Production

Basin	Scenario	Mean Annual Production (MWh)
Stanislaus River	Baseline	1,842,191
	Functional Flows	1,776,742
	40% Full Natural Flow	1,812,811
Tuolumne River	Baseline	2,293,553
	Functional Flows	2,168,582
	40% Full Natural Flow	2,227,830
Merced River	Baseline	385,359
	Functional Flows	328,683
	40% Full Natural Flow	377,310
Upper San Joaquin River	Baseline	4,641,942
	Functional Flows	4,629,111
	40% Full Natural Flow	4,652,743

The three scenarios are baseline, functional flows, and 40 percent full natural flow.

When analyzing hydropower generated per month, each basin exhibited an overall shift of generation compared to earlier in the year. With functional flows, all basins exhibited increased median generation in the range of 1 percent to 15 percent between March and June and commensurate decreases between July and January. The Merced basin had the most dramatic impact, with median monthly generation decreasing by as much as 79 percent in November with functional flows. This shift was less pronounced with 40 percent full natural flows, except for the Merced river, which saw a spike of up to 26 percent in June (Figure 32). Though the Upper San Joaquin and the Stanislaus basins are optimized for hydropower production, the Stanislaus basin showed more variability between the three scenarios. In the Merced, peak hydropower production became more concentrated with flow alteration as compared to baseline; also, functional flows produced more hydropower in February through June as compared to the baseline. The timing of peak hydropower production remained the same in the other basins.

Figure 32: Total Monthly Hydropower Production



The three scenarios are baseline, 40 percent full natural flow, and functional flows. Note the different scales.

While hydropower showed some differences between baseline, 40 percent full natural flow, and functional flow scenarios, the differences in flood control operations were starker. Functional flows resulted in the same or fewer uncontrolled spill days across all basins as compared to a baseline or 40 percent full natural flow scenarios with the exception of the Stanislaus River. The Upper San Joaquin River saw the greatest decrease, with 197 spill days observed under baseline operations and 26 spill days under a functional flow scenario (Table 10); spill days also decreased to 25 under the 40 percent full natural flow scenario. The Merced River similarly saw fewer spill days under a functional flow scenario (no spill days, as compared to three under baseline operations). The Stanislaus River saw an increase in uncontrolled spill days in the 40 percent full natural flow scenario.

Table 10: Number of Uncontrolled Spill Days

Basin	Scenario	Total spill days
Stanislaus River	Baseline	1
	Functional Flows	1
	40% Full Natural Flow	10
Tuolumne River	Baseline	18
	Functional Flows	0
	40% Full Natural Flow	0
Merced River	Baseline	3
	Functional Flows	0
	40% Full Natural Flow	0
Upper San Joaquin River	Baseline	197
	Functional Flows	26
	40% Full Natural Flow	25

Three scenarios are baseline, functional flows, and 40 percent full natural flow.

Finally, though more spill days occur under a functional flow scenario, water supply conditions at the end of each water year decreased for all basins but the Stanislaus. While the Tuolumne showed negligible change from the baseline scenario, the Merced and Upper San Joaquin basins showed fewer years with carryover on October 1. In the Merced basin, the number of years with carryover storage decreased 57 percent with functional flows and 25 percent with 40 percent full natural flows as compared to the baseline (Table 11). In the Upper San Joaquin basin where annual carryover was already low, functional flows decreased carryover to only 7 percent of years (53 years compared to 43 years). Overall, 40 percent full natural flows had a smaller impact on carryover storage than functional flows.

Table 11: Percent of Years With Carry-over Storage on October 1

Basin	Scenario	% Carryover storage years (Oct 1)
Merced River	Baseline	100%
	Functional Flows	82%
	40% Full Natural Flow	95%
Stanislaus River	Baseline	100%
	Functional Flows	100%
	40% Full Natural Flow	100%
Tuolumne River	Baseline	72%
	Functional Flows	31%
	40% Full Natural Flow	54%
Upper San Joaquin River	Baseline	20%
	Functional Flows	7%
	40% Full Natural Flow	10%

Carryover storage is defined as a minimum of 30% fill behind a basin's respective rim dam on October 1.

Discussion

The results of this study support the conclusions of the SWRCB that prioritizing environmental releases will have a negligible impact on hydropower production, regardless on whether the policy follows the percent of full natural flow or functional flow framework. One exception is that the functional flow strategy decreased the amount of hydropower production in the Merced basin, particularly in the Fall. Increased early season flows, particularly during May and June peak flows, were the primary drivers of production and storage availability for these months.

Although hydropower shows minor changes given environmental flow requirements, water supply and flood control show greater effects. Overall, these policies reduced incidents of dam spill, particularly in the Upper San Joaquin. Functional flows generally produce less carryover storage than baseline operations, and generally less than 40 percent full natural flow. During dry years, functional flows tend to release less water than baseline or 40 percent full natural flow scenarios, which could provide more water for other objectives and still be protective of ecological function. The result emphasizes the importance of managing each basin according to its specific WYT. While less water is released, total outflow is more variable under a functional-flow scenario. This supports the hypothesis that flow diversity, rather than a minimum rate, is more important to support ecosystems as long as those lower flows are tailored to a specific ecological function. However, more water is released in wet years, which may allow for less carryover storage. The decrease in spill for flow alteration was likely tied to timing of inflows and when reservoir storage increases – more outflows occurred during natural wet periods. Additional work is needed to explore the relationship between functional flows and current infrastructure capacity.

The differences in WYTs across basins show that variability is important to consider when developing a flow schedule to support ecosystems. Diversity is a key concept underlying successful ecosystem function. Managing for diverse hydrologic conditions could also have important implications for water supply – basins that have drier hydrologic conditions may be required to release more water than the natural background condition would have supported if a single-metric index like the San Joaquin Valley Index is applied. Managing for variability across basins could improve both ecological conditions and water supply for non-environmental uses.

Functional flows affect the four basins differently. While general results may not seem uniformly favorable for hydropower, water supply, and flood control, it’s important to consider each basin separately and determine whether those changes can be accommodated for separately from their effect on other watersheds. For example, functional flows were beneficial in the Stanislaus and Upper San Joaquin basin, though they greatly increased outflow variability in the Merced and Tuolumne basins. The tradeoff may be worthwhile if benefits in the San Joaquin basin result in lower regulatory burdens than in the other watersheds, despite fewer direct benefits. Once fully developed, the functional flows approach to identifying ecologically protective flows in each of the basins considered in this study will allow for a critical assessment of both the immediate potential costs of such flows to other water users within the basin and potential adaptation options for those other users.

Future work will apply the above analysis to climate change projections, including assessing how projections and changes in run-off will alter functional flow templates and SWRCB recommendations. The templates developed for the case study were based on historical hydrological conditions, however, changes in timing and magnitude of flow due to climate change may impact the hydrologic components used. Additionally, as future hydrologic conditions change, the timing and magnitude of full natural flows will also be altered. The second objective of the study will be to assess the capacity for the basin operations to accommodate changes to the hydrologic conditions and shifting flow management templates. The CenSierraPywr framework can be used to examine the variability of future climate change and regulatory constraints on basin operations which will pose new challenges to managers

CHAPTER 4: Technology/Knowledge Transfer Activities

The following discussion describes the effort by the research team to engage relevant stakeholders during the project and delineate deliverables for target audiences that generate impacts beyond the lifespan of the project. It also details the completed and planned transfer activities for the project.

Technical Advisory Committee

An essential stakeholder for this project was also a critical partner in the development of the objectives and outputs. The technical advisory committee (TAC) was comprised of the CEC contract manager and other professionals, including utility managers, water resource modelers, and individuals with technical or market expertise.

The TAC committed to regular progress report meetings and written communications from the research team. During model development, the TAC met several times a year to evaluate progress and provide guidance on detailed technical aspects of the model framework and outputs (Table 12). The feedback was incorporated into tasks, improving realistic model behavior and developing the relevant scenarios for "partial optimization" of the system.

The TAC also provided the team with recommendations and feedback on venues and mediums for disseminating final products with a broader community of end users.

Table 12: Technical Advisory Committee Transfer Tasks

Product	Medium	Success Criteria
TAC Meetings (3-4 per year)	Project fact sheet, presentation slides, in-person discussion	TAC member attendance, meeting feedback summary
Task 2 Preliminary Results	Written results and figures	TAC member feedback
Task 3 Preliminary Results	Written results and figures	TAC member feedback
Draft Final Report	Written report	TAC member feedback
Final Report	Written report	Submission to TAC members

TAC Members:

- Joe O'Hagan, California Energy Commission CAM
- Marco Bell, Merced Irrigation District
- Brent Buffington, Southern California Edison
- Simon Gore, Unites States Department of Energy
- Chris Graham, San Francisco Public Utilities Commission
- Amy Lind, USDA Forest Service

- Sarah Yarnell, University of California, Davis

Additional consultations:

- David Arrate, Department of Water Resources
- Olivia Cramer, Turlock Irrigation District
- Wes Monier, Turlock Irrigation District
- Rufino Gonzalez, US Bureau of Reclamation
- Chadwick Moore, US Bureau of Reclamation

Knowledge Transfer Completed:

- **TAC Meetings and Preliminary Results**: During the project, the research team led several TAC meetings and targeted feedback sessions. Six TAC meetings occurred between 2019-2020, focusing on model development and refinement.
- **Topic Area Meetings**: Additionally, four targeted Topic Area meetings were held with TAC members to address specific questions and areas of interest for the model. Notes and presentation materials from each meeting were reported to the CAM.
- **Final Report**: This report was presented to the TAC for review and feedback. The suggestions and comments provided will be used to shape publications, outreach, and future work.

Planned Knowledge Transfer:

- **Future Engagement:** Interest from TAC members will continue to be cultivated and their engagement regarding the open-source model as well as outreach and future work will be solicited.

Resource Management Community

These end users represent the active energy and water resource professionals the project intends to support. The products transferred to this community must reflect their operational scale, which may encompass one or more hydropower facilities, reservoirs, or water/irrigation districts. The team will supply these stakeholders with actionable and informative project deliverables through the management-relevant model framework and scenarios reported in the final report as well as presentations and written communications.

The interim and final project results will be distributed through existing stakeholder events and publications. Basins and water districts regularly conduct technical meetings during which regional projects and agencies have an opportunity to connect with the end users. Team members participated in these events to gain feedback on interim results and will continue their outreach to disseminate and highlight the final project outcomes.

Knowledge Transfer Completed:

- **Turlock Irrigation District (TID):** the team held a meeting with utility representatives to present interim model development and solicit feedback on TID operations.
- **San Francisco Public Utility District (SFPUC):** The team held a meeting with Chris Graham to specifically discuss SFPUC's research interests and management concerns. Additional feedback on model development was also solicited and SFPUC was able to provide detailed observed data.
- **Merced Irrigation District H_2O Symposium (MIDH2O):** Researchers attended the symposium in 2019 and 2020 to directly communicate with operators and engineers at Merced Irrigation Districts and their other ongoing state and non-agency partners. Senior researchers presented preliminary results and solicited feedback on model development from the attendees. Presentation materials were made available to the CEC contract manager.

Planned Knowledge Transfer:

- **Utility Symposiums:** Events such as the MIDH2O target specific utility managers and their collaborators. The team will continue to engage in MIDH2O and seek out other appropriate similar events for dissemination.
- **Project Brief:** The final report will be used to develop a project brief that can be shared via the CEC library as well as other professional outlets. The project brief will be available within two months of the final report approval.

Professional Community and the Public

The team supports regional decision-making and ratepayers in the study area; additionally, the outcomes of the project will contribute to a greater body of work investigating the relationship between climate change and energy/water management. These stakeholders represent scientists, policy makers, and community groups as well as professional modelers from state agencies and research institutes. The contributions of this project to the above mentioned stakeholder groups are the case study of the central Sierra Nevada and the development of the open-source, transparent model capable of integrating complex constraints and demands on energy/water infrastructure. The team will extend project impacts by enabling further investigations, locally and beyond.

Scientific publications, professional conferences, and online communications will be used to connect with these stakeholders. These mediums are recognized knowledge transfer methods and the team will further identify opportunities that will impact the greatest possible appropriate audience. Conferences provided a venue for preliminary results and feedback from the scientific community, while lasting scientific and other publications will share the final insights.

Knowledge Transfer Completed:

- **Bay-Delta Conference (2017):** Team presented on preliminary project scope to regionally-oriented conference.
- **CERC-WET Annual Meeting (2019):** Project meeting of US and Chinese collaborators regarding model development and preliminary results.
- **European Geosciences Union (2019):** Presentation of preliminary model development and results to an international water resource management audience.

- **ESRI User Conference (2019):** Poster presentation of project scope and preliminary results to an international audience of geospatial analyst.
- **MIDH2O (2019):** Presentation on Merced basin preliminary results and model methods to local water resources managers and their collaborators.
- **American Geophysical Union (2019):** Two presentations of preliminary model results and detailed model methods to an international water resource management audience.
- **American Geophysical Union (2020):** Presentation of model results and methods to an international water resource management audience.
- **CERC-WET Annual Meeting (2020):** Project meeting of US and Chinese collaborators regarding model development and preliminary results.
- **MIDH2O (2020):** Presentation on Merced basin preliminary results and model methods to local water resource managers and their collaborators.

Planned Knowledge Transfer:

- Scientific publications: several publications will be released to provide in-depth analysis for scientific audiences. Publications will be available within 12 months of the final report release. Manuscripts currently in progress include:
    - Analysis of prolonged drought impacts and extreme wet events on hydropower production and system resilience.
    - Impacts of climate change and flow management implementations on hydropower production and ecosystem objectives.

  The team will seek opportunities for disseminating manuscript results via conferences and professional meetings.
- Project Brief and Factsheet: A plain language summary and factsheet that can be distributed via the CEC library or other public and professional outlets. The factsheet will be available within 2 months of Final Report approval.
- Open Source Code: The CenSierraPywr was designed as an all-Python open source model and intended for general use by interested parties. The team will post a final version of the code and documentation on its use to facilitate sharing the repository with other researchers, analysts, and professionals.

Future Work

The CenSierraPywr model has provided a platform for continued investigation into the complex intersection between hydropower energy, climate change, and environmental flow management. The project team will continue to pursue opportunities to work with the CEC and utilities in the state to improve the model and provide timely recommendations to water resource managers and utility operators.

The results of this study will use a multipronged approach to provide outreach to interested parties so that ratepayers can benefit from direct improvements to hydropower energy planning and expand the body of work on this critical issue.

CHAPTER 5: Conclusions

A modeling framework was developed in response to the lack of optimization models representing operating conditions on the ground. Based on the framework, four basin scale models were set up for the SJR system (Stanislaus, Tuolumne, Merced, and Upper San Joaquin basins). The results from these model runs suggest large variations in flow and hydropower production based on GCM selection. Large ranges in potential outcomes will be of little help to operators. The ensemble of GCMs recommended by CCCA4 provide some indication of outcomes, but water resource managers forsee specific stressfull circumstances on their systems, such as prolonged drought. The CCCA4 technical reports suggest developing specific prolonged drought projections in order to test resource management in the state to support future investigations.

Since the results of the 30-year GCM projections will have limited utility for answering specific questions about the constraints of current operations and potential future operational changes, the objective of this study was to understand the impacts of hydrological constraints in the study area. Storage and complex hydropower optimization were critical factors in determining basin resilience from future climate change. The Upper San Jaoquin basin's small amount of storage and large complex facility systems exhibited the highest degree of variability, volatility, and potentially negative impacts due to shifts in runoff. However, the contributions of these basins to downstream ecological objectives could be significantly pertuerbed by future conditions such as upstream basin operations (including minimum IFR and other mandated releases in the model) that do not amerliorate the potential for ecosystem impacts in the future.

As interest and regulatory pressure grows for improving streamflows for fish species and ecosystem processes using dam releases, hydropower energy production will face additional operational constraints on the flexibility of their power generation. Although many different approaches have been proposed (such as functional flows or the SWRCB full natural flows), it is unclear how these alternatives to flow management will intersect with existing operational and climatic dynamics in the Central Sierra Nevada basins. Preliminary implementations of these appraches can be investigated through the framework developed in this study. Our case study on flow management constraints demonstrated that alternative environmental water releases do not necessarily conflict with hydropower generation, however, they must take into consideration all the operational objectives within a basin (for example water supply) and its infrastructure. A basin's operational objective and available storage may impact the feasability of alternative flows. The CenSierraPywr framework's daily timestep provided a more appropriate analytical scale for determining other basin operations' regulatory constraint trade-offs. Further examining these trade-offs in the context of future hydrology will be critical in providing recommendations to the planning process.

Future Work

The analysis presented in this study has provided some meaningful observations that can be applied to planning, however, the open-source model itself can also provide a tool for investigating trade-offs in other specific circumstances. Furthermore, the model has the capacity to create artificial hydrological sequences and implement alternative operational logic as well as different energy grid configurations (and resulting energy prices).

Hydropower and reservoir operations plan at a finer temporal time horizon such as immediate weeks, months, and years than the 2031-2060 GCMs. The annual and monthly averages of a 30-year analysis obscure some of the critical scenarios that managers and operators anticipate. The 2011-2016 drought posed a particular challenge to operations that generated interest in exploring the potential vulnerabilities and areas of resilience for future planning purposes. Artificially constructed climate sequences and stressful climatic sequences of potential concern would provide finer detail insights to management scenarios. Analyzing CenSierraPywr outputs from hypothetical scenarios to replicate extended droughts and various combinations of wet and dry periods would give a better understanding of how the system will react to adverse conditions and what conditions lead to most challenges. Immediate future work stemming from this work will investigate such sequences for the study area.

Although the GCM captures changes to hydrology, future demand was based on a 2019 volume and timing baseline. Urban population growth, changes in crop and land management, and implementation of aquifer recharging in the region will significantly impact the expected demand for reservoir water. California has experienced significant changes in the past 40 years and before the near-term horizon of 2060, it can be expected that these changes to population, land management, and environmental regulations will accelerate. Modeling future demand for water supplies and electricity would improve the understanding of the pressures on the modeled system. Improvements to our understanding of water allocation and demand, such as piecewise linear cost curves for environmental water, would also benefit CenSierraPywr and expand its potential applications.

During the model development, there have been several areas of improvement that could add significant value to CenSierraPywr. However, a better representation of ancillary services is needed, particularly as they are expected to provide a higher value to hydropower operators in California's transition to a low carbon future. In addition to facility behavior upgrades through continued engagement of utilities and operators, basin hydrology improvements will refine the facility behavior accuracy. Current limitations to the hydrological data created interpretation challenges and as CenSierraPywr is applied to more specific questions or facilities, the importance of accurate hydrology will increase.

Finally, the *Pywr* back-end can enable linkages between individual basin models. Although computational costs increase, basin software models can be run together and provide feedback on internal operations. This would be particularly useful if the individual basin models were linked at their outlets to a single "Delta" outflow point and used in a MOEA to help quantify and characterize trade-offs between energy, water and environmental uses/users between different basins. Case studies, such as the alternative flow management, are well suited for this linked analysis as many of the objectives have cumulative effects. Currently, the study areas' facilities are operated with limited synergy. Complex systemic challenges and demands (such as Delta flows) will increase pressure on coordination between facilities, utilities, and basins. Through integrated modeling of multiple basins, the CenSierraPywr approach can be applied to novel problems that can be more easily solved through multi-basin optimizations.

CHAPTER 6: Benefits to Ratepayers

The CenSierraPywr effort has provided a better understanding of climate change impacts in relation to the central Sierra Nevada's changing energy configurations. The flexible framework will continue to support the state in the development and visioning of long-term operation planning. As FERC licenses are updated periodically and state expectations for flow management evolve, hydropower will also face the challenge of balancing production with other water uses. The study offers insights into these potential future flow management trade-offs as well as a framework which can accommodate alternative management in addition to alternative climate scenarios. CenSierraPywr results lay the groundwork for finer analysis of facility resilience but also the development of multi-basin modeling for the study area and beyond.

Additionally, the modeling methods contribute to the science of water systems management and will support future work both in California and beyond. Improvements to these investigations will benefit ratepayers as competing needs for water are heightened due to climate change.

LIST OF ACRONYMS

Term	Definition
AMJ	April-May-June
California ISO	California Independent System Operator
CC	Climate change
CMIP5	Climate Model Intercomparison Project, version 5
CONUS	Conterminous United States
CVP	Central Valley Project
CDWR	California Department of Water Resources
EBHOM	Energy-Based Hydropower Optimization Model
EPIC	Electric Program Investment Charge
ESRL	Earth System Research Laboratory
FERC	Federal Energy Regulatory Commission
GCM	General Circulation Model
GHG	Greenhouse gas
GUI	Graphical user interface
GWh	Gigawatt-hours
HiGRID	Holistic Grid Resource Integration and Deployment
IFR	Instream flow requirement
JAS	July-August-September
JFM	January-February-March
JSON	JavaScript Object Notation
LMP	Locational Marginal Price
LP	Linear Programming
LOCA	Localized Constructed Analogs
MAF	Million acre-feet
MID	Merced Irrigation District
MOEA	Multi-objective evolutionary algorithm
MWh	Megawatt hour, also listed as MW

Term	Definition
NLP	Nonlinear Programming
NOAA	National Oceanic and Atmospheric Administration
NSE	Nash-Sutcliffe efficiency
PBIAS	Percent bias
OAR	Oceanic and Atmospheric Research
OASIS	Open Access Same-time Information System
OND	October-November-December
PSD	Physical Science Division
Pywr	Python Water Resources model
RCP	Representative Concentration Pathway
RMSE	Root Mean Square Error
RSR	RMSE-observations standard deviation ratio
SFPUC	San Francisco Public Utilities Commission
SGMA	Sustainable Groundwater Management Act
SIERRA	Sierra Integrated Environmental and Regulated River Assessment
SJR	San Joaquin River
TAC	Technical Advisory Committee
TAF	Thousand acre-feet
UC	University of California
USACE	United States Army Corps of Engineers
USGS	United States Geological Survey
VIC	Variable Infiltration Capacity
WAHO	Water Allocation and Hydropower Optimization
WEAP	Water Evaluation and Planning
WYT	Water year type

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APPENDIX A: Modeled Hydropower Plant and Reservoir Facilities

Table A-1: Modeled Hydropower Plants Within the Upper San Joaquin River Basin

Hydropower Plant Name	Source Reservoir	Ownership	Production Capacity (MW)*	FERC License ID
Big Creek 1 PH	Huntington Lake	Southern California Edison Co (SCE)	82.9	P-2175
Big Creek 2 PH	Huntington Lake	SCE	67.1	P-2175
Big Creek 2A PH	Shaver Lake	SCE	98.5	P-67
Big Creek 3 PH	Dam Diversion 6 Reservoir	SCE	177	P-120
Big Creek 4 PH	Redinger Lake	SCE	100	P-2017
Big Creek 8 PH	Huntington Lake	SCE	64.5	P-67
Eastwood PH	Balsam Meadows Forebay	SCE	199	P-67
Friant PH	Millerton Lake	Friant Power Authority	30.6	P-2892
Kerckhoff 1 PH	Kerckhoff Reservoir	Pacific Gas & Electric (PG&E)	25.2	P-96
Kerckhoff 2 PH	Kerckhoff Reservoir	PG&E	155	P-96
Mammoth Pool PH	Mammoth Pool Reservoir	SCE	187	P-2085
Portal PH	Florence Lake	SCE	10	P-2174
San Joaquin 1 PH (or A.G. Wishon PH)	Corrine Lake	PG&E	18	P-1354
San Joaquin 1A PH	Manzanita Lake	PG&E	0.4	P-1354
San Joaquin 2 PH	Manzanita Lake	PG&E	3.2	P-1354
San Joaquin 3 PH	Bass Lake	PG&E	4	P-1354

Table A-2 Modeled Reservoirs Within the Upper San Joaquin River Basin (excluding Diversion Reservoirs)

Reservoir Name	Stream	Operated by	Elevation* (feet)	Storage Capacity** (acre-feet, AF)	Dead Storage (acre-feet)
Balsam Meadows Forebay	West Fork Balsam Creek	SCE	N/A	N/A	N/A
Bass Lake	North Fork Willow Creek	PG&E	3369	45,400	300
Florence Lake	South Fork San Joaquin River	SCE	7333	64,574	168
Huntington Lake	Big Creek	SCE	6955	89,766	600
Kerckhoff Lake	San Joaquin River	PG&E	984	4,247	0
Lake Thomas A Edison	Mono Creek	SCE	7648	125,035	0
Mammoth Pool	San Joaquin River	SCE	3333	122,720	2,780
Millerton Lake	San Joaquin River	USBR	564	520,600	17,400
Redinger Lake	San Joaquin River	SCE	1404	35,034	8,914
Shaver Lake	North Fork Stevenson Creek	SCE	5374	135,660	92

Table A-3: Modeled Hydropower Plants Within the Merced River Basin

Hydropower Plant Name	Source Reservoir	Ownership	Production Capacity (MW)	FERC License ID
McSwain PH	McSwain Reservoir	MID	9	P-2179
Merced Falls PH	Merced Falls Reservoir	MID	3.5	P-2467
New Exchequer PH	Lake McClure	MID	94.5	P-2179

Table A-4: Modeled Reservoirs Within the Merced River Basin (excluding Diversion Reservoirs)

Reservoir Name	Stream	Operated by	Elevation (ft)	Storage Capacity (acre-feet)	Dead Storage (acre-feet)
Lake McClure	Merced River	MID	823	1,049,000	300
Lake McSwain	Merced River	MID	1112	9730	0
Merced Falls Reservoir	Merced River	MID	305	900	0

Table A-5: Modeled Hydropower Plants Within the Tuolumne River Basin

Hydropower Plant Name	Source Reservoir	Ownership	Production Capacity (MW)	FERC License ID
Dion R Holm PH	Cherry Creek	San Francisco Public Utilities Commission	165	N/A
Don Pedro PH	Don Pedro Reservoir	Turlock Irrigation District	203	P-2299
Kirkwood PH	Hetch Hetchy Reservoir	San Francisco Public Utilities Commission	118.2	N/A
Moccasin PH	Hetch Hetchy Reservoir	San Francisco Public Utilities Commission	100	N/A

Table A-6: Modeled Reservoirs Within the Tuolumne River Basin (excluding Diversion Reservoirs)

Reservoir Name	Stream	Operated by	Elevation (ft)	Storage Capacity (acre-feet)	Dead Storage (acre-feet)
Cherry Lake	Cherry Creek	San Francisco Public Utilities Commission (SFPUC)	4,660	274,300	0
Don Pedro Reservoir	Tuolumne River	Turlock Irrigation District	791	2,030,000	309,000 acre-ft
Hetch Hetchy Reservoir	Tuolumne River	SFPUC	3773	360,400	0
Lake Eleanor	Eleanor Creek	SFPUC	4662	26,149	39

Table A-7: Modeled Hydropower Plants Within the Stanislaus River Watershed

Hydropower Plant Name	Source Reservoir	Ownership	Production Capacity (MW)	FERC License ID
Angels PH	Angels Forebay	Utica Power Authority	1.4	P-2699
Beardsley PH	Beardsley Lake	Tri-Dam Project & Tri-Dam Power Authority	10	P-2005
Collierville PH	McKays Point Reservoir	Northern California Power Agency	263	P-2409
Donnells PH	Donnell Lake	Tri-Dam Project & Tri-Dam Power Authority	72	P-2005
Murphys PH	Murphy's Forebay	Utica Power Authority	3.6	P-2019
New Melones PH	New Melones Reservoir	USBR	300	N/A
New Spicer Meadow PH	New Spicer Meadow Reservoir	Northern California Power Agency	6	P-2409
Phoenix PH	Lyons Reservoir	PG&E	2	P-1061
Sand Bar PH	Beardsley Afterbays	Tri-Dam Power Authority	16.2	P-2975
Spring Gap PH	Pinecrest Lake	PG&E	7	P-2130
Stanislaus PH	Beardsley Lake	PG&E	91	P-2130
Tulloch PH	Tulloch Reservoir	Tri-Dam Project & Tri-Dam Power Authority	30.6	P-2067

Table A-8: Modeled Reservoirs Within the Stanislaus River Basin (excluding Diversion Reservoirs)

Reservoir Name	Stream	Operated by	Elevation (ft)	Storage Capacity (acre-feet)	Dead Storage (acre-feet)
Beardsley Reservoir	Middle Fork Stanislaus River	Tri-Dam Project	3409	98,500	0
Donnells Reservoir	Middle Fork Stanislaus River	Tri-Dam Project	4642	64,745	2,150
Hunters Reservoir	Mill Creek	Utica Water & Power Authority	3195	253	0
Lyons Reservoir	South Fork Stanislaus River	PG&E	4216	4,850	2.5
New Melones Lake	Stanislaus River	Bureau of Reclamation	1050	2,420,000	0
New Spicer Meadow Reservoir	Highland Creek	Calaveras County Water District	6552	189,000	4702
Pinecrest Lake	South Fork Stanislaus River	PG&E	5620	18,312	0
Relief Reservoir	Summit Creek	PG&E	7231	15,558	0
Lake Tulloch	Stanislaus River	Tri-Dam Power Authority	502	68,400	11,560
Utica Reservoir	North Fork Stanislaus River	Northern California Power Agency	6824	2,334	0

Sources: Energy data from the CEC (https://ww2.energy.ca.gov/almanac/renewables_data/hydro), reservoir elevation from USGS (https://geonames.usgs.gov/apex/f?p=138:1:0::NO), storage capacity from USGS (https://waterdata.usgs.gov/ca/nwis/)

APPENDIX B:
Instream Flow Requirements

Table B-1: Source Documents for Upper San Joaquin River Watershed Instream Flow Requirements

Location of IFR	River Subject to IFR	Applicable FERC Project Number	Accession Number(s) for relevant FERC (e-library documents, or alternate citation)
Above Shakeflat Creek	San Joaquin River	P-2085	Southern California Edison, 2000
Below Balsam Meadows Forebay	Balsam Creek	P-67	Southern California Edison, 2000
Below Bass Lake	North Fork Willow Creek	P-1354	20030916-3068
Below Bear Diversion	Bear Creek	P-67	Southern California Edison, 2000
Below Big Creek 5 Diversion	Big Creek	P-67	Southern California Edison, 2000
Below Big Creek 6 Diversion	San Joaquin River	P-120	Southern California Edison, 2000
Below Bolsillo Creek Diversion	Bolsillo Creek	P-67	Southern California Edison, 2000
Below Browns Creek Ditch	Willow Creek	P-1354	20030916-3068
Below Camp 62 Creek Diversion	Camp 62 Creek	P-67	Southern California Edison, 2000
Below Chinquapin Creek Diversion	Chinquapin Creek	P-67	Southern California Edison, 2000
Below Hooper Creek	Hooper Creek	P-67	Southern California Edison, 2000
Below Huntington Lake	Big Creek	P-2175	Southern California Edison, 2000
Below Kerckhoff Lake	San Joaquin River	P-96	19791108-400019930505-0319
Below Lake Thomas A Edison	Mono Creek	P-2086	Southern California Edison, 2000
Below Manzanita Diversion	North Fork Willow Creek	P-1354	20030916-3068
Below Millerton Lake	San Joaquin River	P-2892	San Joaquin River Restoration Program, 2017
Below Mono Creek Diversion	Mono Creek	P-67	Southern California Edison, 2000
Below Pitman Creek Diversion	Pitman Creek	P-67	Southern California Edison, 2000

Location of IFR	River Subject to IFR	Applicable FERC Project Number	Accession Number(s) for relevant FERC (e-library documents, or alternate citation)
Below Redinger Lake	San Joaquin River	P-2017	20031204-3031
Below San Joaquin 1 Diversion	Willow Creek	P-1354	20030916-3068
Below San Joaquin R and Willow Cr Confluence	San Joaquin River	P-2017	Southern California Edison, 2000
Below Shaver Lake	Stevenson Creek	P-67	Southern California Edison, 2000
No. F. Stevenson Creek above Shaver Lake	North Fork Stevenson Creek	P-67	Southern California Edison, 2000

Table B-2: Source Documents for Merced River Watershed Instream Flow Requirements

Location of IFR	River Subject to IFR	Applicable FERC Project Number	Accession Number(s) for relevant FERC (e-library documents, or alternate citation)
Below Crocker-Huffman Dam	Merced River	P-2699	19640408-4000
Below New Exchequer PH	Merced River	P-1061	19640408-4000

Table B-3: Source Documents for Tuolumne River Watershed Instream Flow Requirements

Location of IFR	River Subject to IFR	Applicable Regulatory Agency	Accession Number(s) for relevant FERC (e-library documents, or alternate citation)
Below Hetch Hetchy Reservoir	Tuolumne River	U.S. Dept of the Interior	San Francisco Planning Department, 2008; The San Francisco Public Utilities Commission, 2014
Below Cherry Creek	Cherry Creek	U.S. Dept of the Interior	San Francisco Planning Department, 2008
Below Lake Eleanor	Eleanor Creek	U.S. Dept of the Interior	San Francisco Planning Department, 2008
Below Don Pedro Reservoir	Tuolumne River	Federal Energy Regulatory Commission	Federal Energy Regulatory Commission, 2019

Table B-4: Source Documents for Stanislaus River Watershed Instream Flow Requirements

Location of IFR	River Subject to IFR	Applicable FERC Project Number	Accession Number(s) for relevant FERC (e-library documents, or alternate citation)
At Murphys Park	Angels Creek	P-2019	20040812-3012
Below Angels Diversion	Angels Creek	P-2699	20030903-3012, 20040607-0105
Below Beardsley Afterbay	Middle Fork Stanislaus River	P-2975	19830909-0087
Below Beaver Creek Diversion	Beaver Creek	P-2409	19820210-0403, 19971112-0303
Below Collierville PH discharge	Stanislaus River	P-2409	19820210-0403
Below Confluence of NF Stanislaus and Beaver Creek	North Fork Stanislaus River	P-2409	19971112-0303
Below Donnells Reservoir	Middle Fork Stanislaus River	P-2005	20060131-0049, 20070207-0174
Below Goodwin Reservoir	Stanislaus River	N/A	National Marine Fisheries Service, 2009a, 2009b
Below Hunters Reservoir	Mill Creek	P-2019	20030903-3013, 20040812-3012
Below Lyons Reservoir	South Fork Stanislaus River	P-1061	19921005-0016, 19941019-3043
Below McKays Point Diversion	North Fork Stanislaus River	P-2409	19820210-0403, 19971112-0303
Below New Spicer Meadow Reservoir	Highland Creek	P-2409	19820210-0403, 19971112-0303
Below NF Stanislaus Diversion Reservoir	North Fork Stanislaus River	P-2409	19820210-0403
Below Philadelphia Diversion	South Fork Stanislaus River	P-2130	20090424-3049

Location of IFR	River Subject to IFR	Applicable FERC Project Number	Accession Number(s) for relevant FERC (e-library documents, or alternate citation)
Below Pinecrest Lake	South Fork Stanislaus River	P-2130	20090424-3049
Below Relief Reservoir	Summit Creek	P-2130	20090424-3049
Below Sand Bar Diversion	Middle Fork Stanislaus River	P-2130	20090424-3049
Below Utica Reservoir	North Fork Stanislaus River	P-11563	20030903-3014

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APPENDIX C: Modeling Applications of Climate Models

Climate models quantitatively simulate the physical drivers of climate and project future climate conditions. Climate models have been developed by teams of experts worldwide from a standard set of experiments that provide the best available source of information on the impact of climate change over the next century (Salvi, Villarini, and Vecchi 2017). Modern climate models use inputs of incoming energy, greenhouse gases, and information about the land, oceans, atmosphere, and cryosphere. Currently, coupled atmosphere-ocean **general circulation models (GCMs)** provide state-of-the-art global simulations. Coupled GCMs divide the atmosphere and ocean into grid cells and apply equations of energy, momentum, and mass transfer within and between cells over many timesteps. They then link the sub-models at the atmosphere-ocean interface. Temperature, wind, and precipitation are examples of parameters that can be estimated over the three-dimensional arrangement of grid cells, with 10–20 vertical layers through the height of the atmosphere, depending on the GCM (Jalota et al. 2018).

The use of contemporary GCMs, such as those used for the Coupled Model Intercomparison Project (CMIP) are key components of regional climate change projections (Schoof and Robeson 2016). In comparison to the third phase of CMIP (CMIP3), the fifth phase (CMIP5) provides improved simulations. The GCMs from the CMIP5 archive include more advanced representations of land use change and external forcing such as solar and volcanic forcing, and anthropogenic aerosol emissions, as well as more types of scenarios and more complex models running at finer resolution (Ishida et al. 2017).

Efforts have been made to standardize the parameters of climate model simulations and allow output comparisons. These include standardized scenarios of greenhouse gas and aerosol emissions as well as land use, known as **Representative Concentration Pathways (RCPs)**. The International Panel on Climate Change (IPCC) has defined "medium-low" and "high" emission scenarios as resulting in 4.5 and 8.5 watt per square meter (W/m^2) of added radiative forcing by year 2100, mainly caused by changes in atmospheric composition. These scenarios are referred to as RCP 4.5 and RCP 8.5 and are commonly applied across various climate models. In current modeling efforts, RCP 8.5 is considered closest to the observed trajectory (Naz et al. 2016). The RCP scenarios are generally similar through 2050, only diverging in the second half of the century (Syphard et al. 2019). The RCP 4.5 is a medium stabilization scenario, which assumes the implementation of emission mitigation policies (Ishida et al. 2017), lower energy consumption, decreased use of croplands and grasslands (led by yield increase and dietary changes), stable methane emissions and a slight increase in CO_2 emissions followed by a decline around 2040 (Jalota et al. 2018). The RCP 8.5 is a very high baseline emission scenario with greenhouse gas emissions increased over time (Ishida et al. 2017), higher energy consumption, increased use of croplands and grasslands to feed a population of 12 billion by 2100 and a lower rate of technology development (Jalota et al. 2018).

Though global climate models provide useful information, regional analyses with finer spatial resolution are needed for jurisdictions like states or countries to prepare for climate change. The resolution of GCM grid cells limits their utility in estimating local or regional extremes without substantial post-processing, especially in regions of large relief (Schoof and Robeson 2016). For instance, hydrologic projections based on raw GCM outputs, typically with resolution on the order of 150–200 km, cannot be used directly for regional-scale water resource management studies due to their coarse resolution (Naz et al. 2016). Producing this regional assessment required additional analytical techniques including bias correction, downscaling, and model selection.

Bias correction accounts for the systematic over- or under-estimation of variables by models due to model error. A multiplicative or additive correction factor can be applied to modeled data, and differences in variance between modeled and observed data can be removed. Previous bias correction methods struggled to preserve the variance of variables across different time scales, and significantly altered the GCM's mean climate change signal. The methods developed for the CCCA4 avoid these shortcomings and improve GCM representation of droughts and floods (Pierce et al. 2015).

Downscaling is the process of estimating finer-scale climate attributes such as temperature, using coarse-scale climate model outputs and finer-scale historical climate records. Due to computational constraints, even the best GCMs operate on a relatively coarse spatial resolution. For example, the HadGEM1 model uses a grid of 1.875 degrees in longitude and 1.25 degree in latitude in the atmosphere, and one degree in longitude and one-third to one degree in latitude in the ocean (Martin et al. 2006). This is insufficient for regional climate change studies, given the influence of finer-scale topography on climate. Statistical downscaling consists of developing statistical relationships among historical records and the coarse scale data and applying techniques like regression and splining. Constructed analogs are one type of statistical downscaling; earlier constructed analog techniques found multiple days in the historical record that locally best resemble the modeled day and calculated a weighted average.

The 4th Climate Change Assessment (CCCA4), completed in 2018, is an effort to analyze GCMs at a finer resolution assessment. For the CCCA4 report, a newer technique called Localized Constructed Analogs (LOCA) was used. The LOCA method has shown a superior performance to its predecessors, being adopted for policy making and climate adaptation purposes (Pierce, Cayan, and Thrasher 2014b). LOCA finds the single best matching day within a 1- by 1-degree box and scales variable values to match those of that day. By avoiding multiple days' averages, LOCA better maintains regional patterns of precipitation as well as daily extremes and variability (Pierce, Cayan, and Thrasher 2014b).

Lastly, **model selection** is needed to reduce the computational requirements for climate change impact studies. The CMIP coordinates research experiments among 32 participating coupled GCMs. For the CCCA4, the California Climate Action Team Research Working Group selected a subset of four CMIP5 models that best reproduced extremes and variability of precipitation and temperature for California over the time period of 2015-2100: HadGEM2-ES (Warm/dry), CNRM-CM5 (Cool/wet) CanESM2 (balance between HadGEM2-ES and CNRM-CM5), and MIROC5 (spans the range covered by the three other models) (Table C-1) (Kravitz 2017). Based on experience, it was recommended that at minimum RCP 4.5 and RCP 8.5 emission scenarios should be run on these four models to detect the anthropogenic climate change signal (Pierce et al. 2009, Pierce et al. 2016). The ensemble of these four models have been used in recent studies under the RCP 8.5 (Tarroja, Chiang, AghaKouchak, Samuelsen, et al. 2018; Tarroja, Chiang, AghaKouchak, and Samuelsen 2018; Tarroja et al. 2019) and RCP 4.5 and 8.5 (Sleeter et al. 2019). The Working Group also recommended six additional models for use (CCSM4, CESM1-BGC and GFDL-CM3 from America, CMCC-CMS and

HadGEM2-CC from Europe and ACCESS1-0 from Australia) which have been incorporated into the analysis within this report.

California Department of Water Resources' (DWR's) Climate Change Technical Advisory Group (CCTAG) sought to choose among the CMIP5 models a recommended subset of models for usage for the CCCA4 (Lynn et al., 2015). CCTAG ran all the eligible models, and then performed the downscaling process on the raw model outputs to produce finer spatial resolution estimates (approximately 6 km by 6 km) that are more relevant for local-to-small regional scale analyses. The next GCM selection criterion was the ability of the downscaled outputs to reproduce historical extremes and variability of precipitation and temperature for California over the time period of 2015-2100. GCMs were eliminated according to performance in replicating the regional climate structure. Moreover, as GCMs are numerical codes that solve fundamental conservation and process equations, some are very closely related as they share common numeric or physical components (Lynn et al. 2015). The subset of the 10 GCMs chosen by the CCTAG screening exercise was selected to avoid redundancy by avoiding more than two GCMs from the same modeling group, while still be representative of the CMIP5 results. The final subset of four GCMs selected as priority for the CCCA4 is considered to represent the range of plausible future scenarios for the state (Kravitz 2017).

Although GCMS are similar in several ways, different outcomes may occur due to the variation in grid characteristics, spatial resolution, parameterization schemes, model subcomponents, and climate sensitivity for different forcing factors (Jalota et al. 2018). The uncertainties in climate projections may arise from GHG emission scenarios uncertainty, internal atmospheric variability, and model uncertainty due to the selection of GCMs, which can be avoided through the incorporation of an ensemble of simulations (Ishida et al. 2017).

Table C-1: Study 4 Core General Circulation Models

Model	Center	Climate behavior	Atmospheric Resolution (Lon. × Lat.)	Vertical Levels in Atmosphere
CNRM-CM5	National Centre of Meteorological Research, France	Cool/Wet	1.4×1.4	31
HadGEM2-ES	Met Office Hadley Center, UK	Warm/Dry	1.88×1.25	38
CanESM2	Canadian Centre for Climate Modeling and Analysis	Balance between Warm/Dry and Cool/Wet	2.8×2.8	35
MIROC5	Centre for Climate System Research (CCSR), Japan	Complement/ Cover range of outputs	1.4×1.4	40

Models recommended by the CCCA4 Climate Action Team Research Working Group and some of their attributes.

Source: adapted from Rupp et al. 2013.

MIROC5 includes atmosphere, ocean, sea ice and land components, with considerably better climatological featuresthan the previous software version (MIROC3.2).especially regarding precipitation, zonal mean atmospheric fields, equatorial ocean subsurface fields, and the simulation of El Niño–Southern Oscillation (ENSO) (Watanabe et al. 2010). According to Webb *et al.* (2015), its convection scheme has a mass flux closure similar to the Arakawa–Schubert scheme that considers multiple cloud types with different cloud tops, but with a varying entrainment rate in time and space depending on the temperature and humidity. In this GCM, the shallow convection is not treated separately, but the scheme may represent some shallow cumulus clouds (Webb et al. 2015).

The **CNRM-CM5** is an Earth system model designed to run climate simulations and consists of several existing models designed independently and coupled through the OASIS software (Jalota et al. 2018). This GCM has a deep convection scheme that follows a mass-flux approach without a separate treatment of shallow convection; it triggers under low level moisture convergence (large and sub-grid scale)and vertical conditional instability (Webb et al. 2015).

HadGEM2-ES is a coupled Earth system model that comprises an atmospheric GCM and an ocean GCM that includes the terrestrial and ocean carbon cycle and tropospheric chemistry (Jalota et al. 2018). The deep convective parametrization is a mass flux scheme with convective momentum transport and a simple radiative representation, in which shallow convection is treated separately (Webb et al. 2015). The terrestrial vegetation and carbon are represented by a dynamic global vegetation model that simulates the coverage and carbon balance of five different types of vegetation (Jalota et al. 2018). The ocean biology and carbonate chemistry include limitation of plankton growth by macro- and micronutrients and also simulates emissions of dimethyl sulfide (anti-GHG) to the atmosphere (Jalota et al. 2018).

CanESM2 is the fourth-generation atmosphere-ocean general circulation model; it resolves salient features of the global atmospheric-ocean circulation while still permitting the execution of large initial-condition ensembles of model simulations to sample internal variability under different external forcing (Jalota et al. 2018). There is different vertical spacing, ranging from 10m near the surface (there are 16 levels in the upper 200m) to nearly 400m in the deep ocean (Jalota et al. 2018). Murdock, Cannon and Sobie (2013) compared the results of 12 CMIP5 future climate projection models in North America. CanESM2 showed similar results to the ensemble median, however it projected larger precipitation increases in some regions, such as in the Western US.

Sleeter *et al.* (2019) used downscaled climate data from the LOCA to represent future climate conditions for the RCP 4.5 and RCP 8.5 scenarios simulated by CanESM2, CNRM-CM5, HadGEM2-ES, and MIROC5 to project future changes in ecosystem carbon balance in California. Under the RCP 8.5 scenario, CanESM2, HadGEM2-ES, and MIROC5, projected net ecosystem carbon balance declines caused by droughts for the years 2063, 2058–2059 and 2059 respectively, following a similar pattern to the 2013 actual drought. . This finding suggests that severe multiyear drought conditions may occur in the future. Although the climate model results were inconsistent to a certain level, the authors found that MIROC5 and HadGME2-ES projected the largest cumulative declines in carbon storage, CanESM2 projected an average decline and CNRM-CM5 was associated with the smallest decline.

Tarroja *et al.* (2019) also used the four GCMs under the RCP 8.5 with meteorological inputs from LOCA to investigate the implication of hydropower variability from climate change for highly renewable electric grid in California. The authors mention that HadGEM2-ES and MIROC5 models exhibited increases in greenhouse gas emissions, with a large total water volume introduced to the reservoirs but with a greater year-to-year variability that led to a decrease in hydropower generation. HadGEM2-ES had a greater inter-annual precipitation variability, spanning a large range between maximum and minimum. The wetter scenarios produced by CanESM2 and CNRM-CM5 exhibited decreases in GHG emissions and higher availability of hydropower generation in meeting peak demands.

Syphard *et al.* (2018) used the GCMs CNRM-CM5 and MIROC5 under the RCP 8.5 emission scenario, to map fire probability under climate change in the Sierra Nevada throughout the 21st century. CNRM-CM5 projected increases in annual and summer precipitation, with a maximum annual increase at the end of the century. Meanwhile MIROC5, projected a slightly higher annual precipitation initially followed by a lower precipitation at the end of the century, also with a higher summer precipitation. Both patterns were generally consistent across elevations. Both models also projected an increase in temperature and climatic water deficit, which were greater in the MIROC5 model.

Syphard *et al.* (2019) considered the relative influence of climate and housing pattern on fire patterns and structure loss for three diverse California landscapes projected by CNRM-CM5 and MIROC5 using the RCP 8.5. The future trends in temperature and precipitation varied across regions in both models. In parts of the study area, the CNRM-CM5 scenario had consistently greater mean annual precipitation, while MIROC projected drier conditions. Both models predicted decreased annual precipitation in another region. The response to changes in summer precipitation were flipped between the GCMs, in which the Cool/Wet model, CNRM-CM5, projected drier summers than MIROC5, although MIROC5 projected a greater increase in annual temperature and with a greater geographical variation for all study areas by 2049. According to the authors, decadal fluctuations that reflect idiosyncrasies of the GCM run, were strongest in MIROC5 in the North Coast.

Ishida *et al.* (2017) studied the impacts of climate change on watershed-scale precipitation through the 21st century in Northern California based on future climate projections from the priority models HadGEM2-ES and MIROC5 and the recommended model CCSM4 (Cool/Dry) under the RCP4.5 and RCP 8.5. In this study, the GCM-VIC models predicted the annual basin-average precipitation for wet and dry years differently, however 10-year moving averages of the CCSM4 and the HadGEM2-ES ensemble averages were mostly similar to each other, predicting increases in rainfall. MIROC5 projected relatively lower annual basin-average precipitation in all watersheds after the 2040 water year. The results from the ensemble averages of the annual basin-average precipitation fluctuate throughout thewatershed studies. Close results were observed under the RCP4.5 and RCP8.5 scenarios during the early and mid-21st century and a more pronounced increase in precipitation was noted for the late 21st century under RCP 8.5.

Previous studies in California incorporated other models than those used here.. For instance, Dettinger (2013) used the 10 GCMs mentioned by CCTAG, meanwhile Cheng *et al.* (2016) used the CCSM4 model alone. An ensemble of 14 GCMs comprised of a mix of the recommended and priority GCMs as well as others such as CMCC-CM, MIROC-ESM-CHEM and CSIRO-Mk3-6-0, were used by Ullrich *et al.* (2018). Previous California studies also projected climate changes by employing ensembles of 12 (Swain et al. 2014), 24 (Yu et al. 2020), or even 34 CMIP5 models (Berg and Hall 2015).

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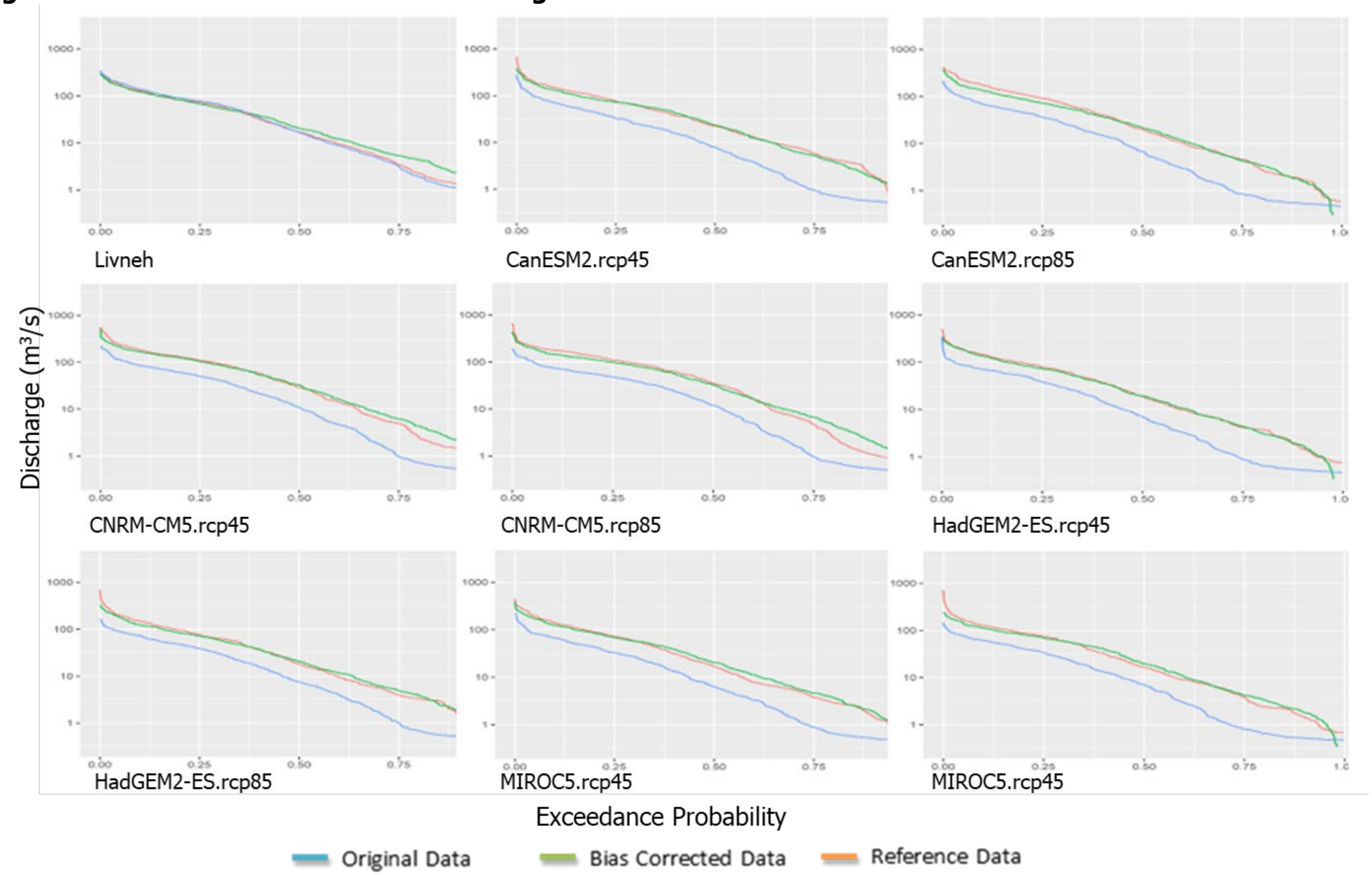
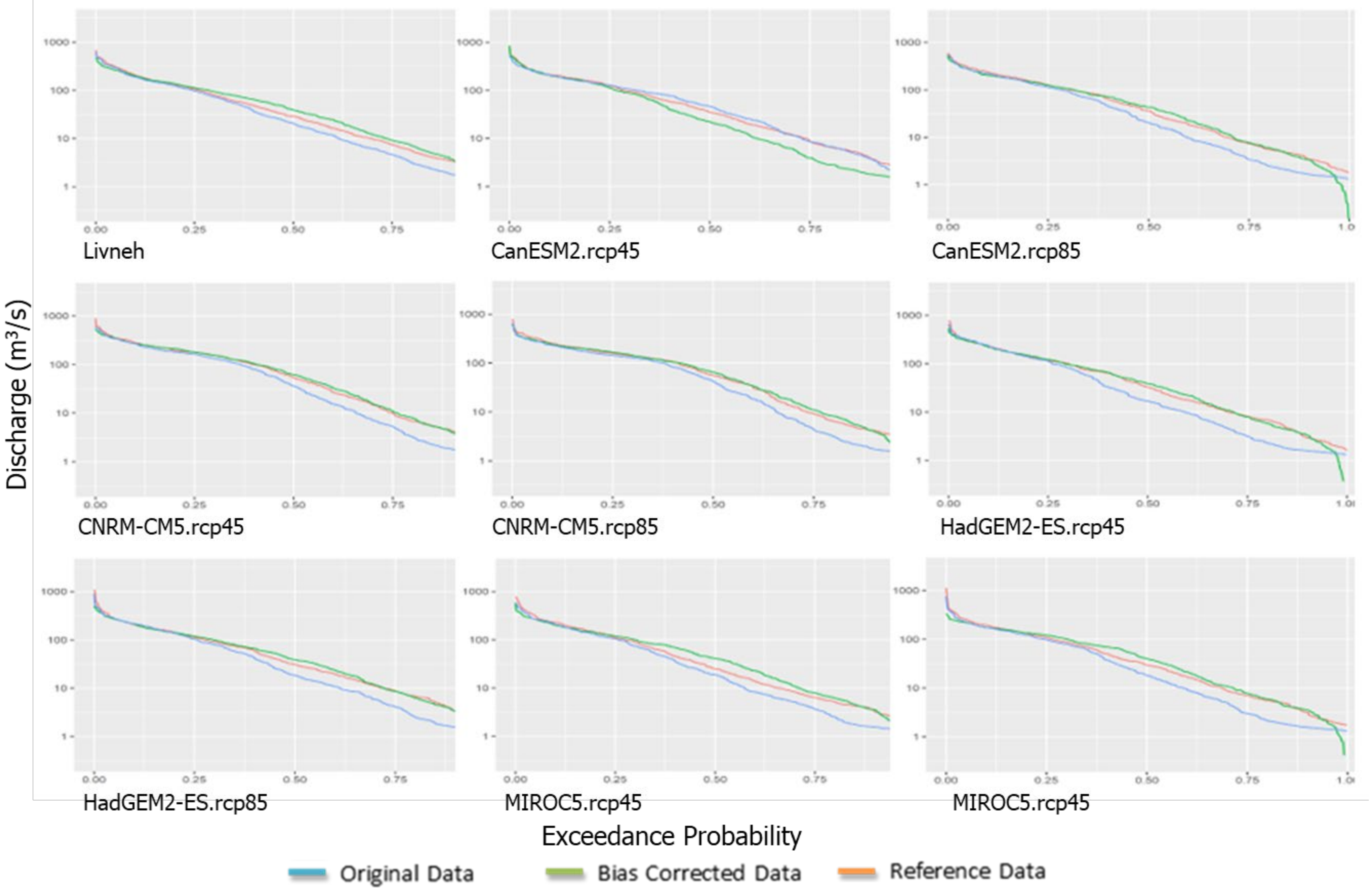
APPENDIX D:
Model Performance and Bias Correction

Figure D-1: Flow Duration Curves Showing Bias Corrected Results for Stanislaus Basin for Four Core GCMs



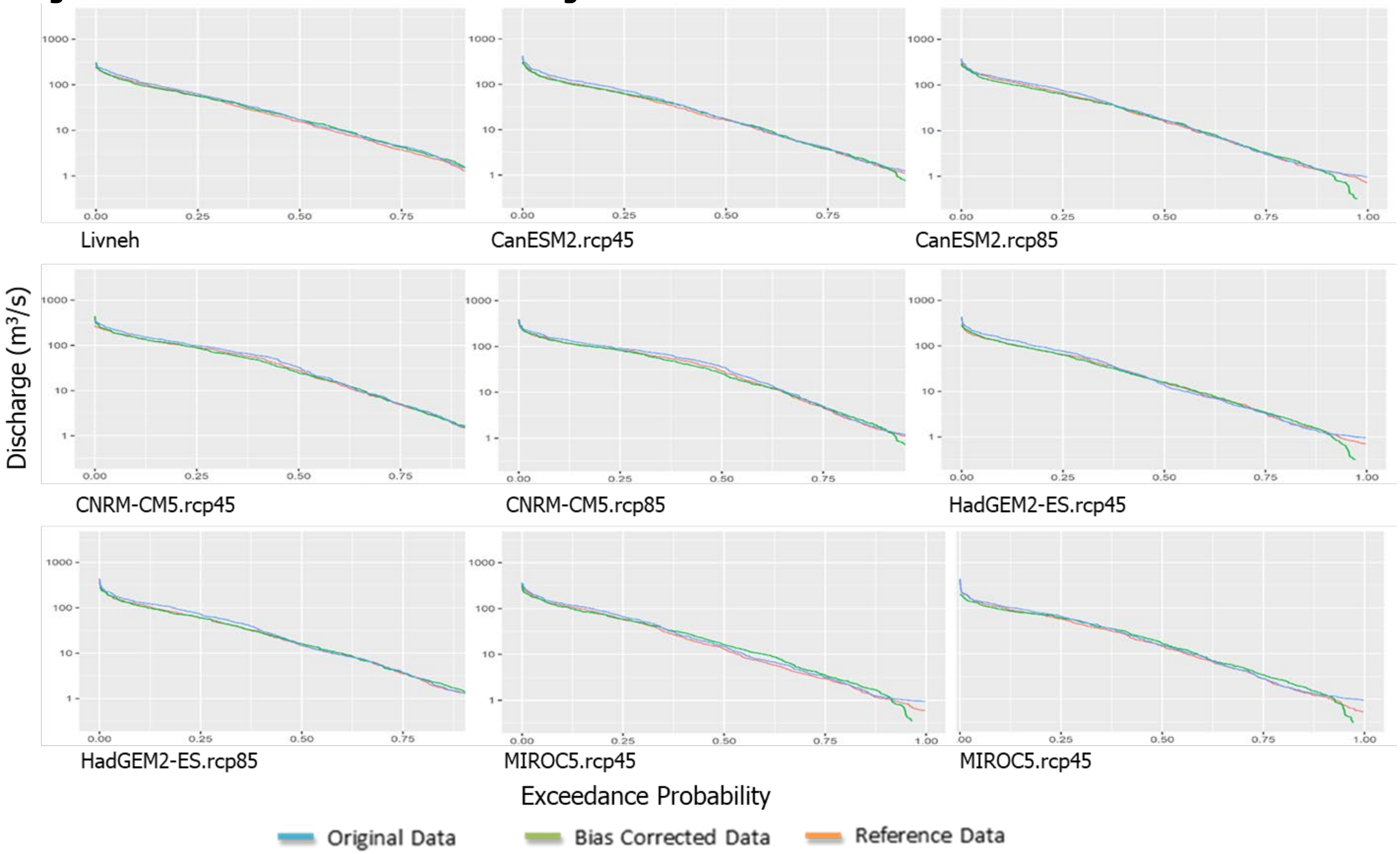
Source: Original data from VIC Data Repository (UC Berkeley)

Figure D-2: Flow Duration Curves Showing Bias Corrected Results for Tuolumne Basin for Four Core GCMs



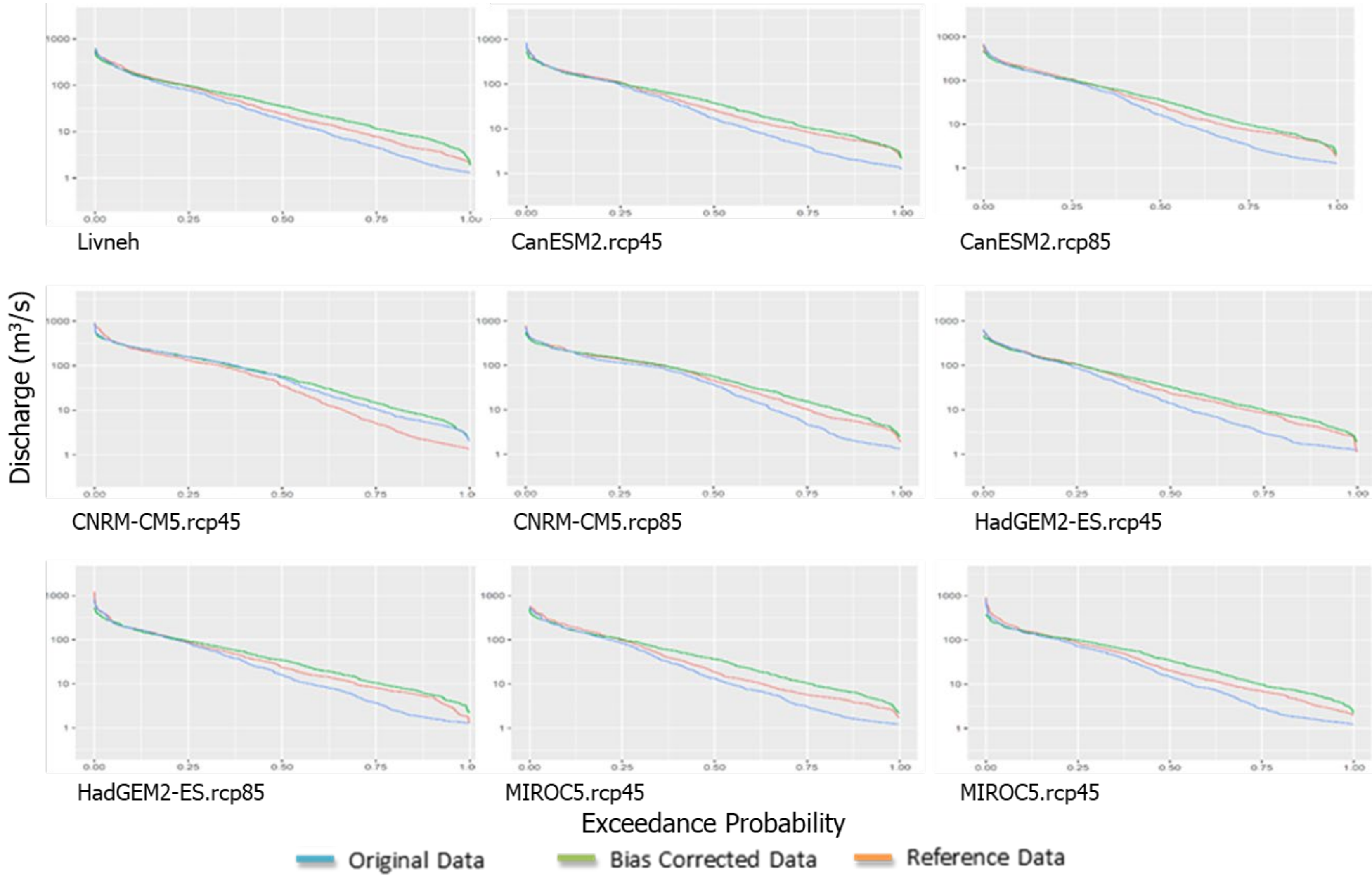
Source: Original data from VIC Data Repository (UC Berkeley)

Figure D-3: Flow Duration Curves Showing Bias Corrected Results for Merced Basin for Four Core GCMs



Source: Original data from VIC Data Repository (UC Berkeley)

Figure D-4: Flow Duration Curves Showing Bias Corrected Results for Upper San Joaquin River Basin for Four Core GCMs



Source: Original data from VIC Data Repository (UC Berkeley)

Table D-1: Performance Metrics for Basin Bias Correction of Historical (Livneh) and GCM Hydrological Data

		Stanislaus River			Tuolumne River			Merced River			Upper San Joaquin River		
Scenario	RCP	NSE	RSR	PBIAS	NSE	RSR	PBIAS	NSE	RSR	PBIAS	NSE	RSR	PBIAS
Livneh	-	0.90	0.31	-0.05	0.94	0.25	0	0.90	0.32	-0.03	0.91	0.31	-0.01
ACCESS1-0	4.5	0.88	0.35	0	0.71	0.54	0	0.91	0.30	0	0.77	0.48	0
	8.5	0.81	0.43	0	0.61	0.63	0	0.82	0.42	0	0.63	0.61	0
CanESM2	4.5	0.71	0.54	-10.47	0.83	0.41	-0.12	0.92	0.28	-0.11	0.84	0.39	-0.12
	8.5	0.64	0.60	-10.13	0.84	0.40	0.02	0.90	0.32	0.03	0.90	0.32	-0.01
CCSM4	4.5	0.91	0.30	0	0.85	0.39	0	0.94	0.25	0	0.86	0.38	0
	8.5	0.87	0.36	0	0.79	0.46	0	0.88	0.35	0	0.79	0.46	0
CESM1-BGC	4.5	0.92	0.29	0	0.84	0.40	0	0.91	0.29	0	0.87	0.35	0
	8.5	0.92	0.29	0	0.84	0.40	0	0.91	0.31	0	0.84	0.39	0
CMCC-CMS	4.5	0.87	0.36	0	0.76	0.49	0	0.86	0.38	0	0.79	0.46	0
	8.5	0.86	0.38	0	0.69	0.56	0	0.84	0.40	0	0.68	0.56	0
CNRM-CM5	4.5	0.87	0.37	-6.13	0.87	0.36	-0.08	0.92	0.28	-0.07	0.74	0.51	8.64
	8.5	0.85	0.38	-5.41	0.84	0.40	-0.01	0.90	0.32	0.04	0.84	0.40	0.01
GFDL-CM3	4.5	0.91	0.30	0	0.82	0.43	0	0.91	0.31	0	0.85	0.39	0
	8.5	0.88	0.35	0	0.80	0.44	0	0.91	0.30	0	0.87	0.37	0
HadGEM2-CC	4.5	0.90	0.31	0	0.82	0.43	0	0.92	0.28	0	0.85	0.39	0
	8.5	0.85	0.39	0	0.74	0.51	0	0.89	0.37	0	0.74	0.51	0
HadGEM2-ES	4.5	0.78	0.47	-12.57	0.83	0.44	0	0.90	0.32	0	0.87	0.36	0
	8.5	0.74	0.51	-12.56	0.73	0.52	0	0.87	0.36	0	0.65	0.59	0
MIROC5	4.5	0.83	0.41	-9.37	0.69	0.56	0	0.87	0.36	0	0.74	0.51	0
	8.5	0.81	0.44	-8.83	0.62	0.61	0	0.84	0.41	0	0.60	0.63	0

Table D-2: Model Performance Metrics for Hydropower Energy Generation Facilities

Basin	Facility	NSE	RMSE	PBIAS
Stanislaus	Angels PH	-0.34	228.68	-4.70
	Beardsley PH	0.29	2,107.91	-8.40
	Collierville PH	0.57	23,745.45	26.80
	Donnells PH	0.10	14,299.50	35.60
	Murphys PH	-0.59	947.75	37.30
	New Melones PH	0.56	23,118.86	-10.80
	New Spicer Meadow PH	-1.59	1,686.33	6.30
	Phoenix PH	-0.99	617.26	51.90
	Sand Bar PH	-0.19	4,634.89	-21.40
	Spring Gap PH	-1.87	2,653.63	27.80
	Stanislaus PH	-0.14	12,434.93	-4.10
Tuolumne	Dion R Holm PH	0.06	35,735.14	-9.30
	Don Pedro PH	0.58	21,446.94	-9.30
	Kirkwood PH	0.08	19,162.06	4.30
	Moccasin PH	-0.05	10,508.80	2.50
Merced	McSwain PH	0.23	3,189.79	-1.40
	Merced Falls PH	0.66	511.31	-2.50
	New Exchequer PH	0.65	12,686.73	-5.50
Upper San Joaquin	Big Creek 1 PH	0.05	17,823.61	0.50
	Big Creek 2 PH	0.11	13,238.50	-0.70
	Big Creek 2A PH	-0.19	24,533.04	4.30
	Big Creek 3 PH	0.54	24,925.07	-9.30
	Big Creek 4 PH	0.61	13,216.81	-6.10
	Big Creek 8 PH	0.07	11,629.05	-5.50
	Eastwood PH	0.41	15,699.77	-9.60
	Friant PH	-1.01	7,608.62	-79.70
	Kerckhoff 1 PH	0.19	6,839.98	-7.50
	Kerckhoff 2 PH	0.63	18,041.07	-9.10
	Mammoth Pool PH	0.65	23,228.40	-2.80
	Portal PH	-0.15	2,307.89	-7.80
	San Joaquin 1 PH	0.04	3,971.12	-5.40
	San Joaquin 1A PH	-0.04	96.80	-12.10
	San Joaquin 2 PH	-0.18	871.51	3.80
	San Joaquin 3 PH	-0.06	1,050.63	1.00

Table D-3: Model performance Metrics for Hydropower Facility Flow

Basin	Facility	NSE	RMSE	PBIAS
Stanislaus	Angels PH	NaN	NaN	NaN
	Beardsley PH	-0.03	186.38	0.50
	Collierville PH	0.65	190.32	27.20
	Donnells PH		283.17	-212.90
	Murphys PH	0.57	5.32	7.10
	New Melones PH	0.59	757.15	-3.60
	New Spicer Meadow PH	-0.91	222.96	45.50
	Phoenix PH	NaN	NaN	NaN
	Sand Bar PH	-0.01	191.65	-2.50
	Spring Gap PH	-1.66	30.72	43.10
	Stanislaus PH	-0.31	141.80	2.30
Tuolumne	Dion R Holm PH	0.19	305.56	-9.60
	Don Pedro PH	NaN	NaN	NaN
	Kirkwood PH	0.57	249.99	-1.20
	Moccasin PH	-0.02	137.53	1.90
Upper San Joaquin	Big Creek 1 PH	0.08	176.59	9.10
	Big Creek 2 PH	0.14	161.54	3.40
	Big Creek 2A PH	-0.18	214.91	8.80
	Big Creek 3 PH	0.57	587.54	-6.20
	Big Creek 4 PH	0.65	600.63	0.00
	Big Creek 8 PH	0.23	300.47	2.90
	Eastwood PH	0.22	279.87	27.60
	Friant PH	NaN	NaN	NaN
	Kerckhoff 1 PH	0.17	444.17	8.30
	Kerckhoff 2 PH	0.69	697.96	-4.50
	Mammoth Pool PH	0.64	431.24	-1.60
	Portal PH	0.17	317.64	3.20
	San Joaquin 1 PH	0.07	60.81	-0.10
	San Joaquin 1A PH	0.02	59.27	10.10
	San Joaquin 2 PH	-0.15	57.15	12.10
	San Joaquin 3 PH	-0.10	52.66	-2.30

NaNs produced where historical data are unavailable. Length of historical record varies between reservoirs.

Table D-4: Model Performance Metrics for Reservoir Storage

Basin	Facility	NSE	RMSE	PBIAS
Stanislaus	Beardsley Reservoir	0.50	18.54	13.90
	Donnells Reservoir	0.52	13.88	7.90
	Hunter Reservoir	NaN	NaN	NaN
	Lake Tulloch	0.18	4.98	2.80
	Lyons Reservoir	-0.44	1.48	-12.50
	New Melones Lake	0.48	447.62	-21.70
	New Spicer Meadow Reservoir	-3.20	76.20	-65.10
	Pinecrest Reservoir	0.45	3.88	-13.40
	Relief Reservoir	0.55	3.48	12.50
	Union-Utica Reservoir	0.26	0.70	-7.10
Tuolumne	Cherry Lake	0.12	56.98	7.50
	Don Pedro Reservoir	0.84	115.24	0.00
	Hetch Hetchy Reservoir	0.35	60.34	-8.30
	Lake Eleanor	0.22	7.73	-5.40
Merced	Lake McClure	0.75	119.66	9.10
	Lake McSwain	NaN	0.03	-0.30
Upper San Joaquin	Bass Lake	-0.50	8.92	7.70
	Florence Lake	0.23	19.01	2.90
	Huntington Lake	-0.82	27.67	27.20
	Kerckhoff Lake	-1.71	0.30	2.90
	Lake Thomas A Edison	0.25	30.97	-6.40
	Mammoth Pool Reservoir	0.18	33.38	14.30
	Millerton Lake	-1.34	166.01	40.40
	Redinger Lake	-14.04	11.10	27.70
	Shaver Lake	0.07	31.62	-13.70

NaNs produced where historical data are unavailable. Length of historical record varies between reservoirs.

Table D-5: Model Performance Metrics for Basin Outflow Locations

Basin	Location	NSE	RMSE	PBIAS
Stanislaus	Oakdale Irrigation District	0.92	53.64	-0.90
	Phoenix Canal Outflow	NaN	NaN	NaN
	South San Joaquin Irrigation District	0.88	147.13	-0.80
	Stanislaus River Outflow	0.28	778.39	-18.50
Tuolumne	Groveland	NaN	NaN	NaN
	Modesto Irrigation District	0.77	152.19	-0.80
	SFPUC	0.00	105.34	-19.50
	Tuolumne River Outflow	0.74	968.37	-2.30
	Turlock Irrigation District	0.80	281.56	-1.00
Merced	Merced River Outflow	0.72	528.38	0.00
	MID Main	0.81	272.33	6.20
	MID Northside	0.81	11.18	3.00
Upper San Joaquin	CVP Friant-Kern Canal	0.70	695.08	-0.10
	CVP Madera Canal	0.10	376.66	9.10
	San Joaquin River Outflow	0.32	1,325.84	-0.70

NaNs produced where historical data are unavailable. Length of historical record varies between outflow locations.

Table D-6: Model Performance Metrics for Instream Flow Requirement Locations

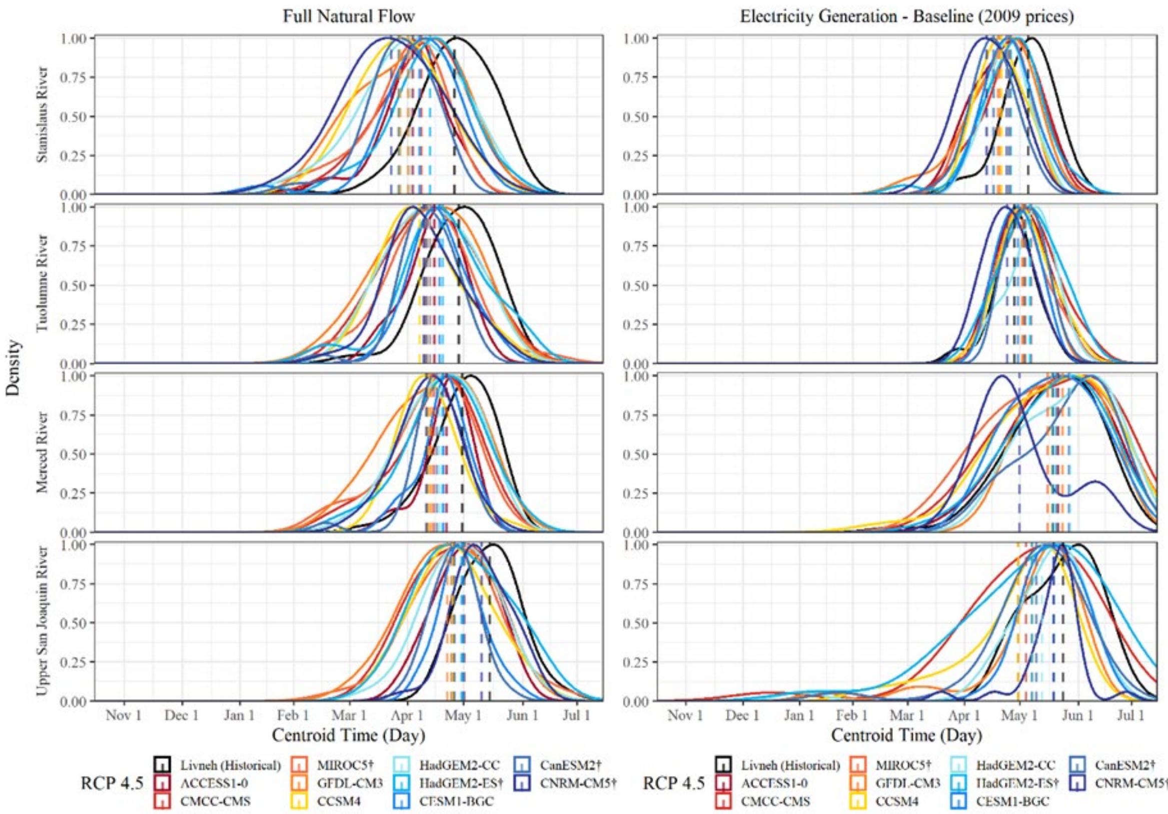
Basin	Instream Flow Requirement	NSE	RMSE	PBIAS
Stanislaus	Donnell Lake Spill	NaN	NaN	NaN
	IFR at Murphys Park	0.57	5.32	7.10
	IFR bl Angels Div	-2.13	3.25	-38.60
	IFR bl Beardsley Afterbay	0.11	577.26	-5.50
	IFR bl Beaver Creek Diversion Dam	0.62	33.94	43.10
	IFR bl Collierville PH discharge	-14.56	1,265.51	-115.80
	IFR bl confluence of NF Stanislaus Beaver Creek	0.62	104.59	8.40
	IFR bl Donnell Lake	-1.81	11.62	17.80
	IFR bl Goodwin Reservoir	0.28	778.39	-18.50
	IFR bl Hunter Reservoir	-42,805	64.21	-1,478.10
	IFR bl Lyons Res	0.83	77.16	-10.80
	IFR bl McKays Point Div	0.46	87.62	2.10
	IFR bl New Spicer Meadow Reservoir	-0.22	190.89	33.80
	IFR bl NF Stanislaus Div Res	-28.91	80.10	-35.40
	IFR bl Philadelphia Div	0.55	14.09	14.70
	IFR bl Pinecrest Lake	NaN	NaN	NaN
Stanislaus (cont'd)	IFR bl Relief Reservoir	NaN	NaN	NaN
	IFR bl Sand Bar Div	-223.05	215.91	-158.70
	IFR bl Utica Reservoir	-10,984	61.28	-281.50
	New Melones Lake Flood Control	NaN	NaN	NaN
Tuolumne	Don Pedro Lake Spillway	NaN	NaN	NaN
	IFR at La Grange	0.74	968.37	-2.30
	IFR bl Cherry Lake	0.23	135.30	-7.60
	IFR bl Hetch Hetchy Reservoir	0.34	738.73	3.10
	IFR bl Lake Eleanor	0.61	162.22	14.20
	Moccasin Fish Hatchery	NaN	NaN	NaN
Upper San Joaquin	IFR above Shakeflat Creek	0.73	757.62	-27.60
	IFR bl Balsam Forebay	-299.65	5.20	-24.70
	IFR bl Bass Lake	0.61	37.30	28.80
	IFR bl Bear Div	0.50	77.00	-2.80
	IFR bl Big Creek 5 Div	-0.43	138.87	24.70
	IFR bl Big Creek 6 Div	0.69	895.76	-9.40
	IFR bl Bolsillo Creek Div	-0.29	3.05	87.80
	IFR bl Browns Creek Ditch	NaN	NaN	NaN
	IFR bl Camp 62 Creek Div	-0.13	3.83	-58.30

Basin	Instream Flow Requirement	NSE	RMSE	PBIAS
Upper San Joaquin (cont'd)	IFR bl Chinquapin Creek Div	0.10	1.36	37.10
	IFR bl Hooper Creek	0.51	170.68	11.00
	IFR bl Huntington Lake	-0.29	4.50	-2.90
	IFR bl Kerckhoff Lake	0.60	587.32	0.50
	IFR bl Lake Thomas A Edison	-1.02	218.60	-3.10
	IFR bl Manzanita Div	NaN	NaN	NaN
	IFR bl Millerton Lake	0.32	1,325.84	-0.70
	IFR bl Mono Creek Div	0.27	57.24	35.70
	IFR bl Pitman Creek Div	0.15	54.53	13.20
	IFR bl Redinger Lake	0.74	788.02	-10.40
	IFR bl San Joaquin 1 Div	NaN	NaN	NaN
	IFR bl San Joaquin R and Willow Cr confluence	NaN	NaN	NaN
	IFR bl Shaver Lake	-0.19	121.90	20.30
	IFR No. Fk. Stevenson Creek above Shaver Lake	-0.17	20.40	65.30

NaNs produced where historical data are unavailable. Length of historical record varies between outflow locations.

APPENDIX E:
RC P4.5 Results

Figure E-1: Distribution Density of Full Natural Flow and Energy Generation for Each Basin and GCM (RCP 4.5) Compared to Historical



Distribution density of (left) full natural flow (FNF) and (right) energy generation for each basin and each GCM (RCP 4.5) compared to historical. Dashed lines indicate date of centroid.

Figure E-2: Annual Hydropower Energy Production (GWh) per Basin for Historical (Livneh) and Near Future GCMs (2031-2060) RCP 4.5

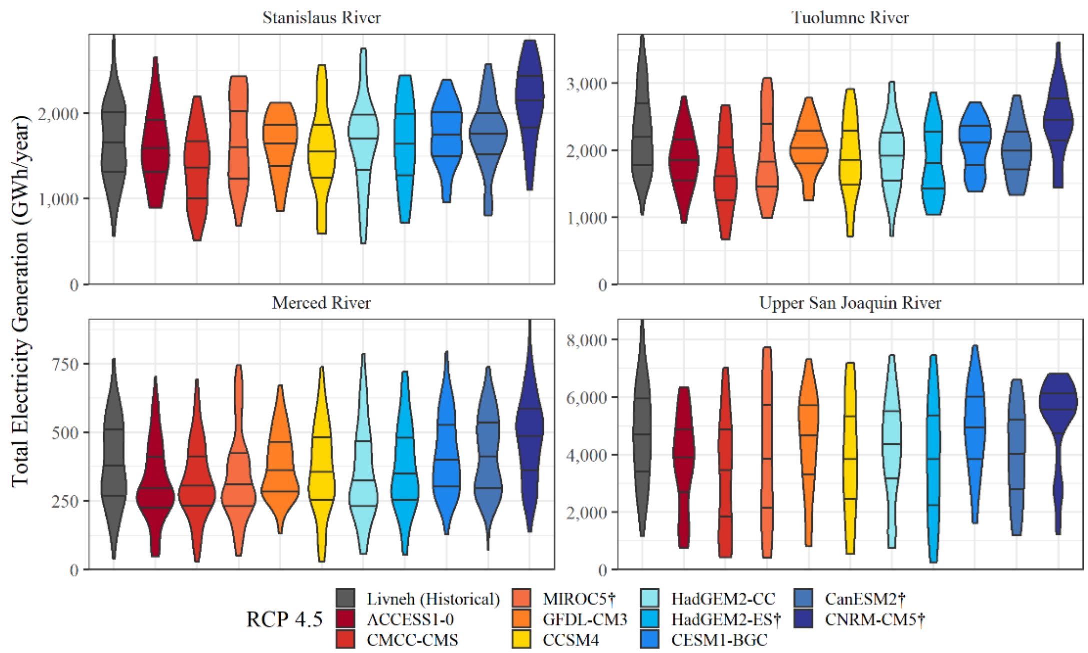
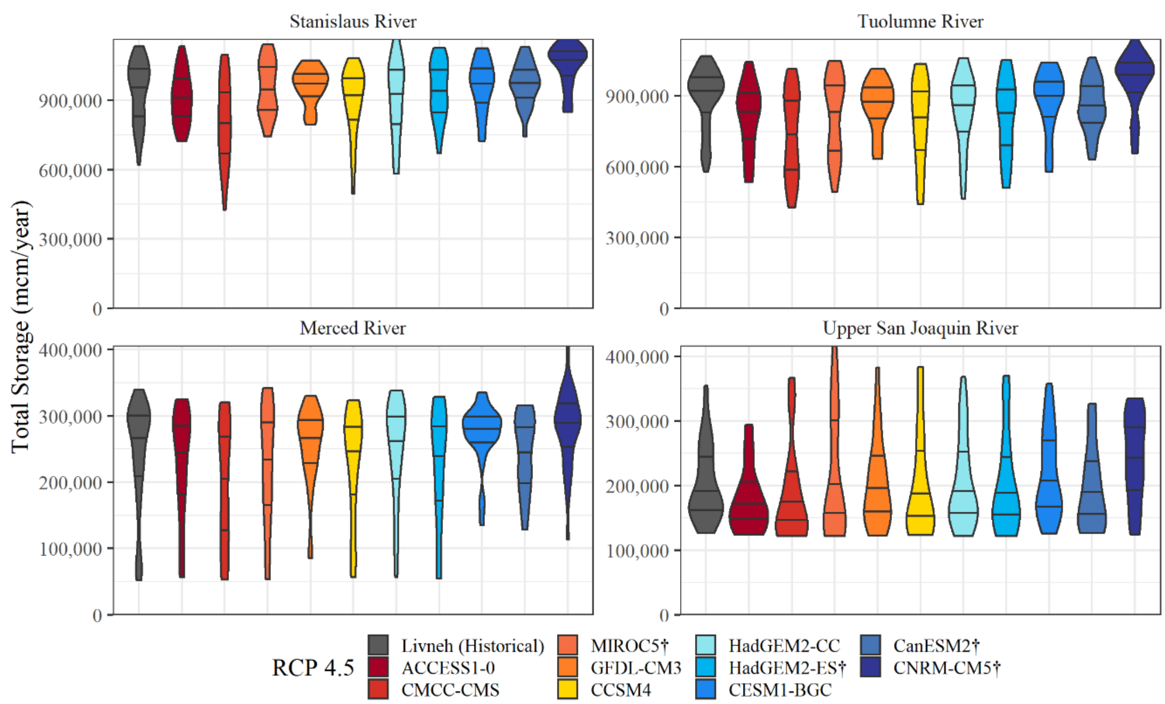
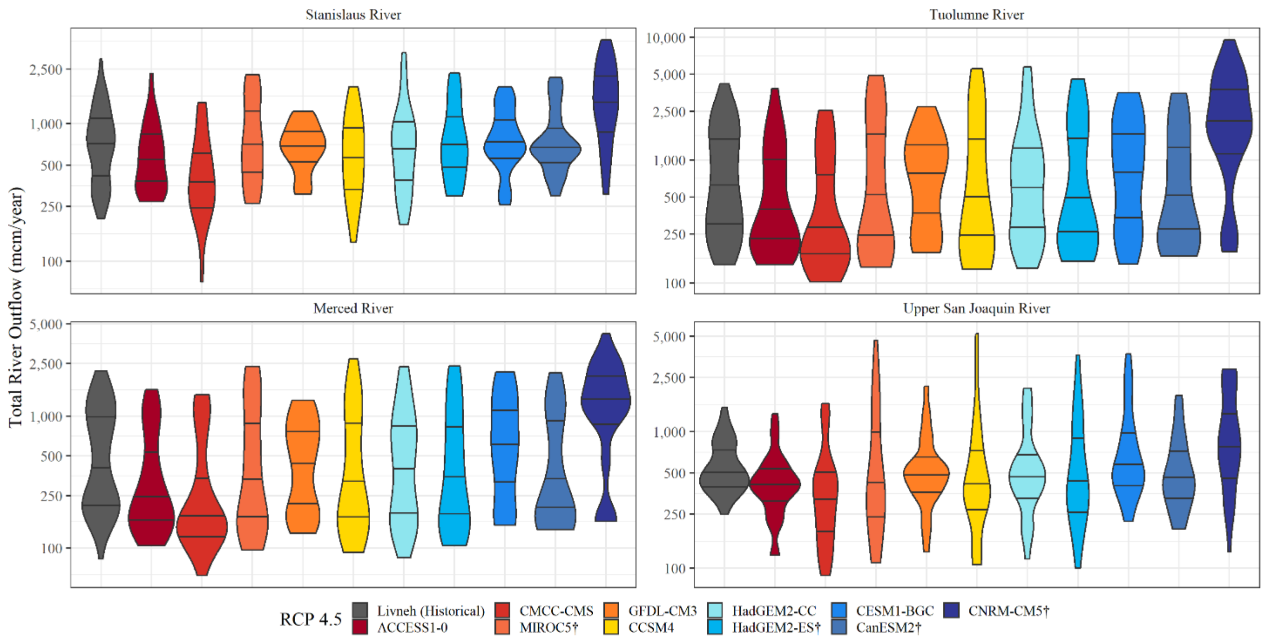


Figure E-3: Annual Reservoir Storage (mcm) per Basin



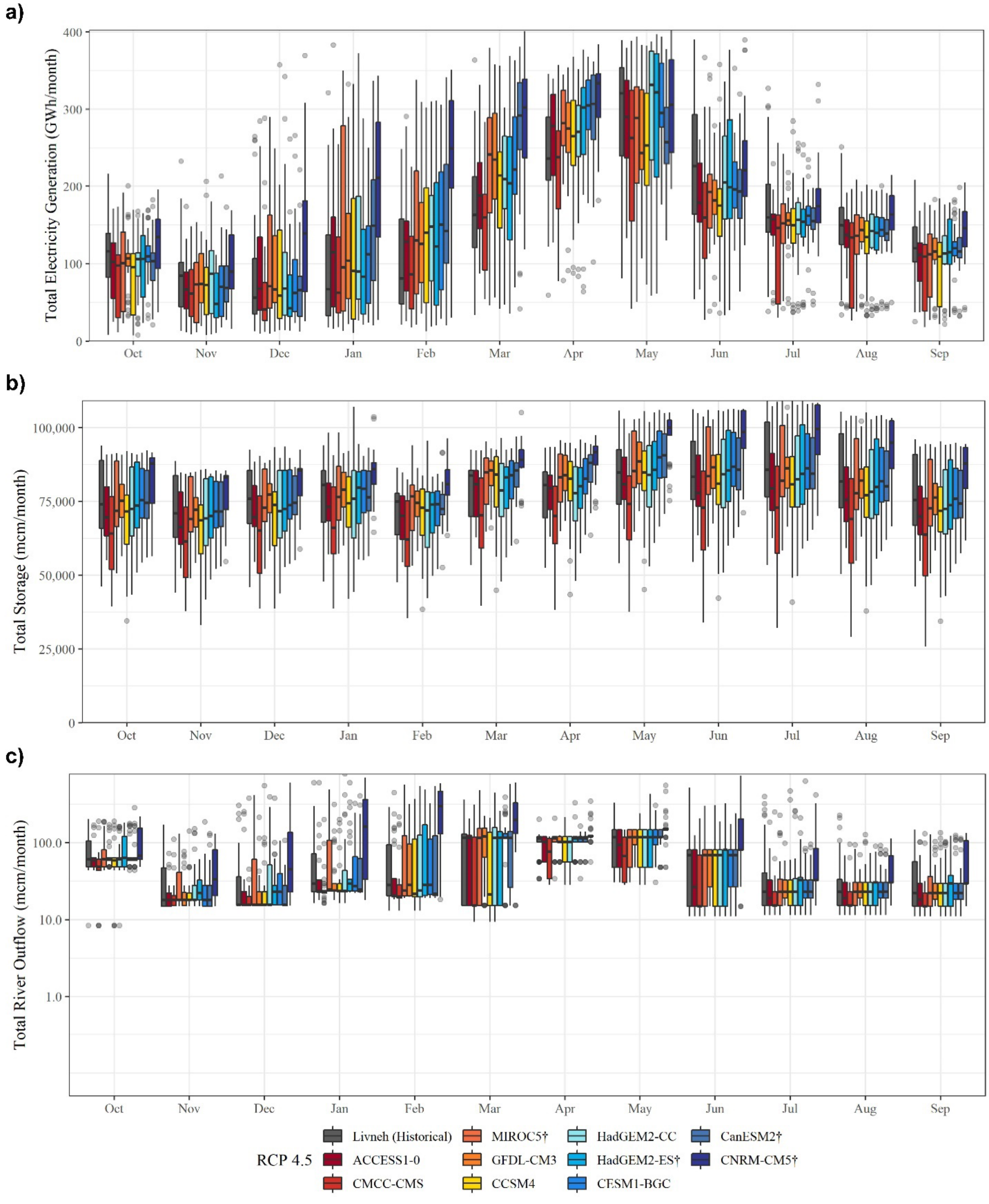
Basin storage for historical (Livneh) and near future GCMs (2031-2060) RCP 4.5.

Figure E-4: Annual Outflow (mcm) per Basin



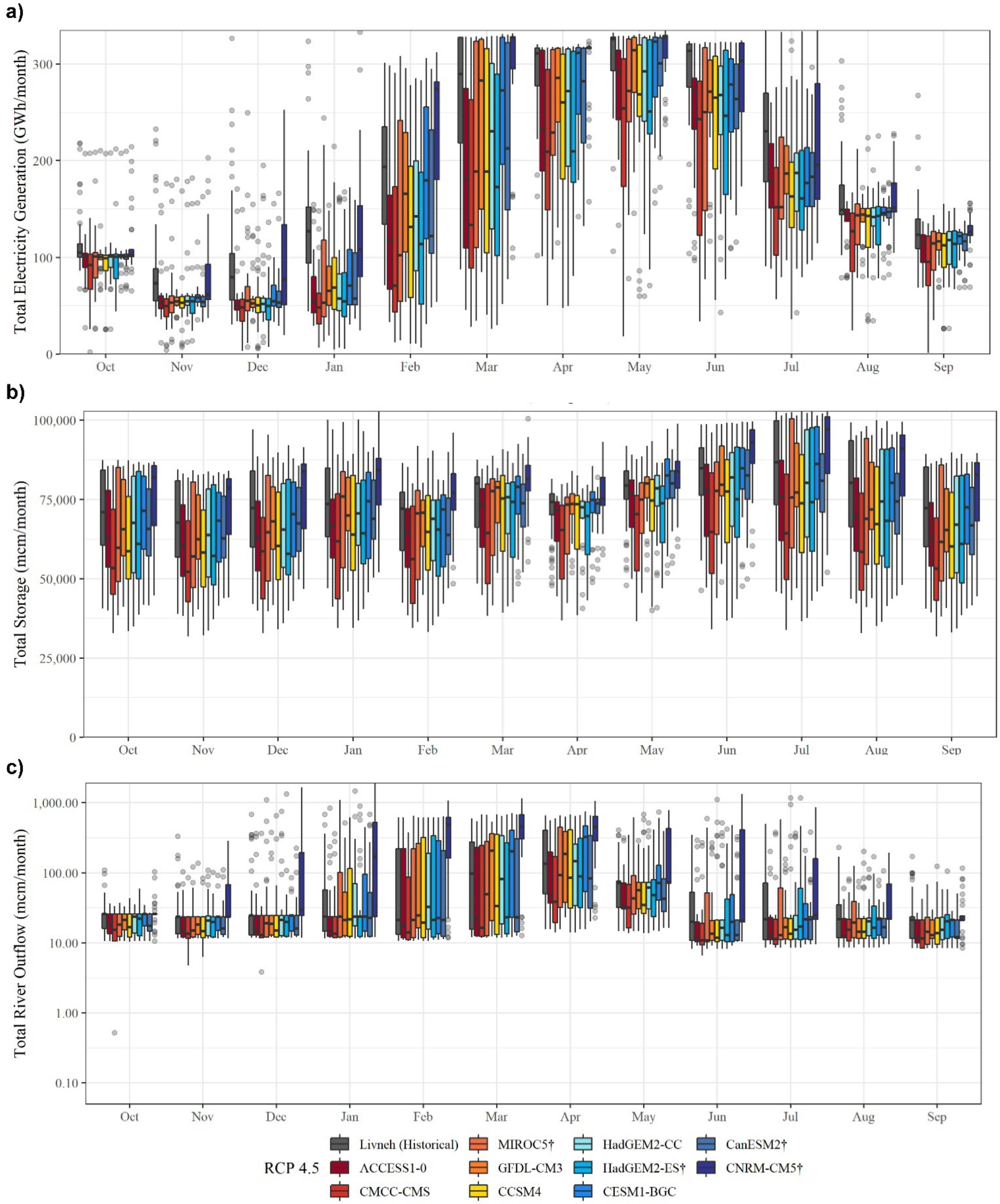
For historical (Livneh) and near future GCMs (2031-2060) RCP 4.5.

Figure E-5: Stanislaus River Basin Monthly Hydropower, Storage, and Outflow



Total monthly (a) hydropower production (GWh) and (b) reservoir storage (mcm) and (c) basin outflow (mcm log10) for historical and near future GCM (2031-2060) RCP 4.5.

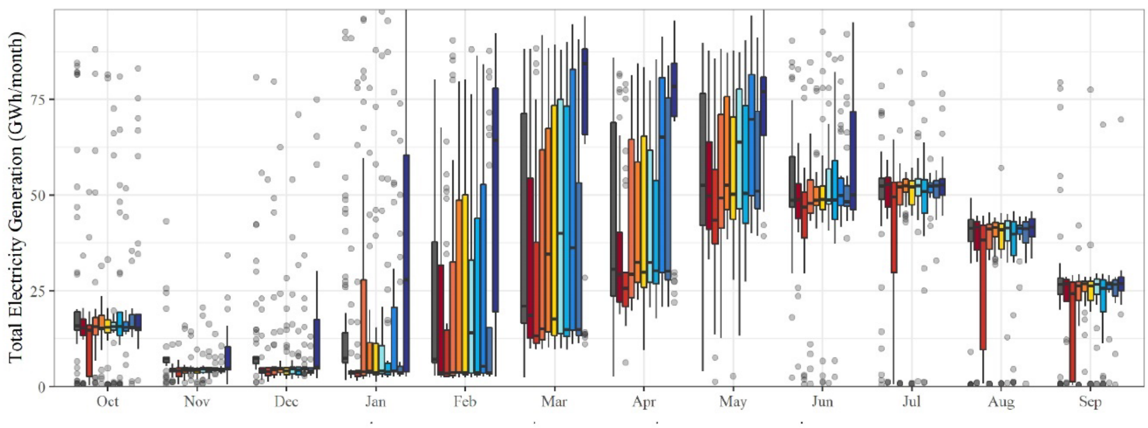
Figure E-6: Tuolumne River Basin Monthly Hydropower, Storage, and Outflow



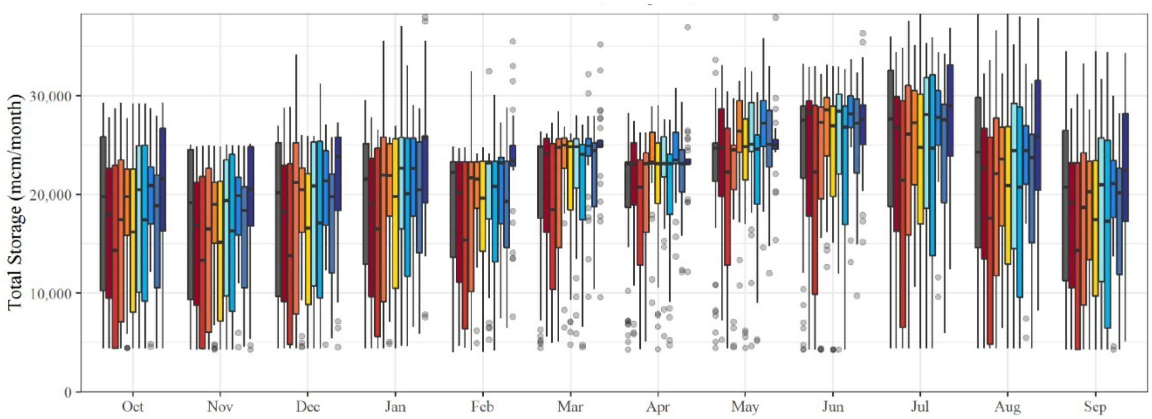
Total monthly (a) hydropower production (GWh) and (b) reservoir storage (mcm) and (c) basin outflow (mcm log10) for historical and near future GCM (2031-2060) RCP 4.5.

Figure E-7: Merced River Basin Monthly Hydropower, Storage, and Outflow

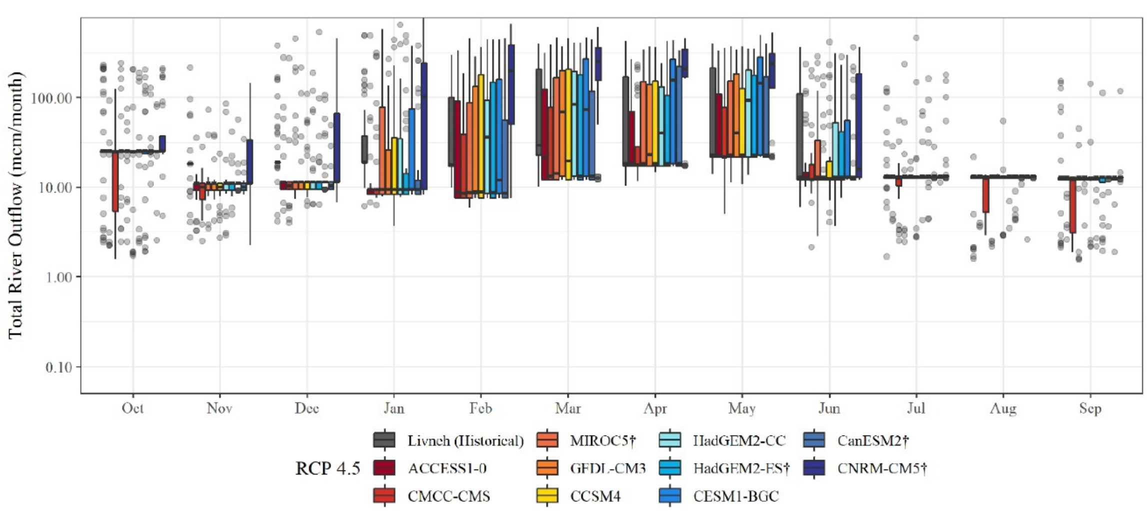
a)



b)

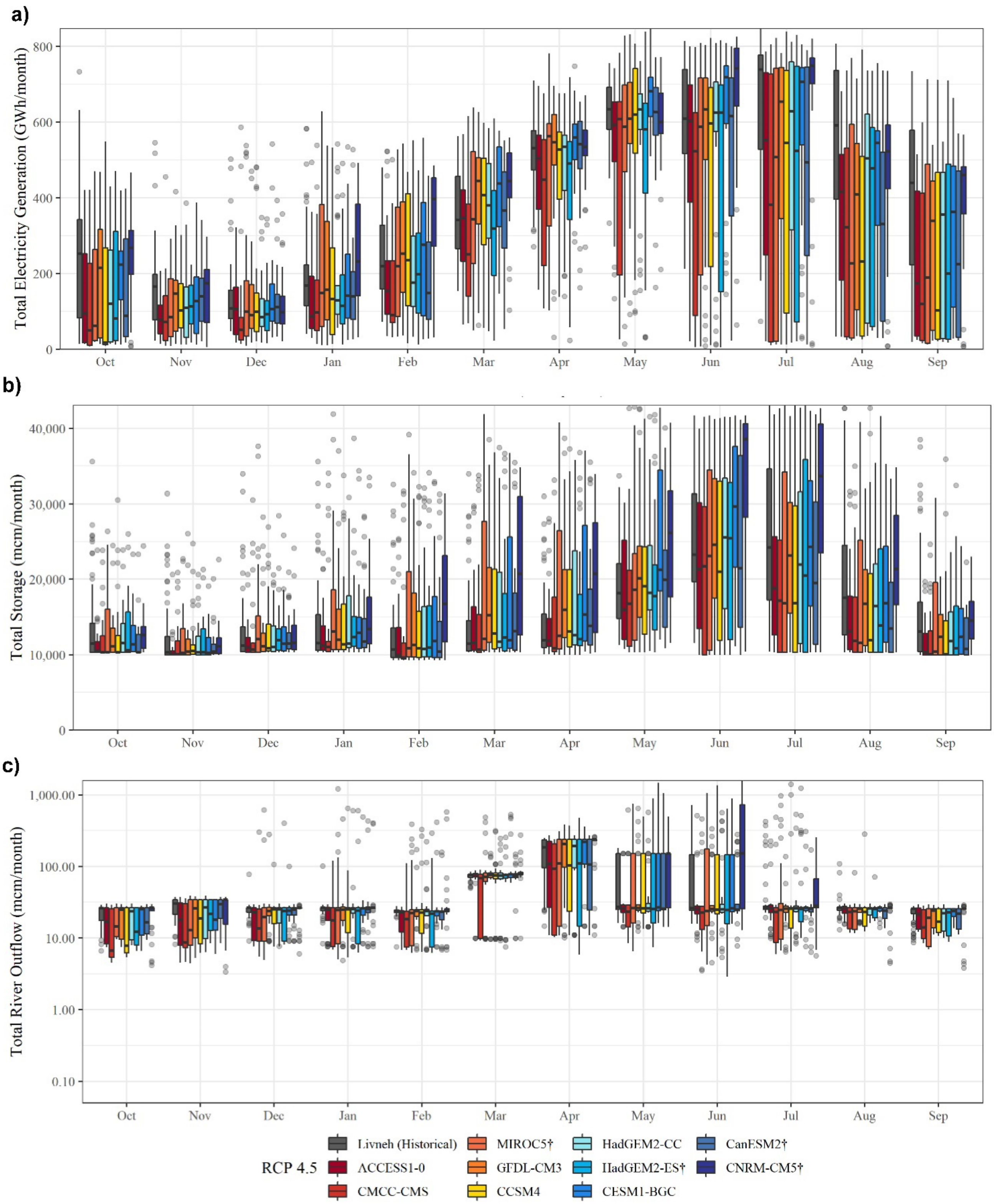


c)



Total monthly (a) hydropower production (GWh) and (b) reservoir storage (mcm) and (c) basin outflow (mcm log10) for historical and near future GCM (2031-2060) RCP 4.5.

Figure E-7: Upper San Joaquin River Basin Monthly Hydropower, Storage, and Outflow



Total monthly (a) hydropower production (GWh) and (b) reservoir storage (mcm) and (c) basin outflow (mcm log10) for historical and near future GCM (2031-2060) RCP 4.5.