WATER AND ENERGY SECTOR VULNERABILITY TO CLIMATE WARMING IN THE SIERRA NEVADA: Simulating the Regulated Rivers of California's West Slope Sierra Nevada

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ABSTRACT

Climate warming is expected to affect the beneficial uses of water in the Sierra Nevada, impacting nearly every resident of California. This paper describes the development and results from an integrated water resource management model encompassing water operations and hydropower generation for the west slope Sierra Nevada spanning the Feather River basin in the north to the Kern River basin in the south at the weekly time step. This model application includes management of reservoirs, run-of-river hydropower plants, water supply demand locations, conveyances, and instream flow requirement. Model validation indicates that most major hydropower turbine flows were simulated well, with wetter years modeled more effectively than drier years. The results of this work indicated that hydropower generation will be reduced by approximately 8 percent with 6°C (10.8°F) warming, consistent with other studies, with a conservative parameterization of no change in precipitation. Reservoir operations adapt to capture earlier and greater runoff volumes that result from earlier and greater runoff due to climate warming. Seasonal compensation in operations is insufficient to overcome warming mediated losses.

Keywords: water energy nexus, water management, climate change, non-stationary climate, regulated rivers, reservoirs, habitat, Sierra Nevada

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Section 1: Summary

In California's Sierra Nevada Mountains, water is managed for hydropower production, instream flows, urban and agricultural water supply, recreation, and flood regulation, affecting nearly every resident of California. However, there is currently no single model or tool that can be used to assess multi-sector effects of changes in physical and other conditions that will be affected by climate warming, such as inflow hydrology. Climate warming is expected to alter runoff magnitude and timing in the Sierra Nevada, affecting all beneficial uses of water. Spring/summer snowmelt runoff will decrease, while winter runoff from precipitation will increase, shifting runoff timing to earlier in the year. Warming will also decrease total runoff. , Existing studies quantifying effects of climate warming on water resources in the Sierra Nevada are either temporally coarse (monthly), limited in spatial extent (single watersheds), or single-purpose. In this study, we sought to improve understanding of how regulated flows in the Sierra Nevada may be vulnerable to climate warming and to help develop adaptation strategies to manage water resources for competing demands. To do this, we developed a weekly time step water resources management model for the west slope Sierra Nevada, from the Feather River watershed in the north to the Kern River watershed in the south. The model is developed with the Water Evaluation and Planning (WEAP) modeling system and includes management of reservoirs, run-of-river hydropower plants, water supply demand locations, conveyances, and instream flow requirements. The model is applied with two different datasets to represent runoff with historical-, near-, mid-, and far-term warming: one that uses WEAP and considers regional air temperature increases of 0°C, 2°C, 4°C, and 6°C (0°F, 3.6°F, 7.2°F, and 10.8°F) and another that uses the variable infiltration capacity (VIC) hydrologic model with downscaled global circulation model (GCM) climate data.

Key findings include:

- Most major hydropower turbine flows are simulated well. Reservoir storage is also generally well simulated, mostly limited by the accuracy of inflow hydrology.
- With air temperature increase of 6°C, system wide hydropower generation is reduced by 9 percent.
- Most reductions in hydropower generation occur in the highly productive watersheds in the northern Sierra Nevada. The central Sierra Nevada sees less reduction in annual runoff and can adapt better to changes in runoff timing. Generation in southern watersheds is expected to decrease.
- Reservoirs adapt to capture earlier runoff, but mostly decrease in mean reservoir storage with warming due to decreasing annual runoff.

We highlight important model limitations and recommend improvements, including refining representation of climate change effects and a more sophisticated, project-specific hydropower simulation method.

Section 2: Introduction

Climate warming is expected to affect the beneficial uses of water in California's Sierra Nevada Mountains, including hydropower, water supply, ecosystem benefits, and flood control, directly affecting nearly every resident of California. However, no single model or tool is available to assess potential regional vulnerabilities to climate change across a range of water use sectors in sufficient detail to inform management decisions.

To help fill this management information gap, we developed a watershed scale, weekly time step simulation model of regulated flows for 15 watersheds in the upper Sierra Nevada, called the Sierra Integrated Environmental and Regulated Rivers Assessment (SIERRA) model. This paper describes the model scope, methods, calibration, a subset of results, and a summary of model limitations and recommendations for improvement. Results from a model as comprehensive in management scope as SIERRA are extensive. This study focuses on hydropower generation, the dominant management objective in the upper Sierra Nevada. Focusing on hydropower also allows for comparisons of results with other regional models.

SIERRA builds directly on the work of Young et al. (2009) and Mehta et al. (2011). Young et al. (2009) used the Water Evaluation and Planning system (WEAP) to model the unimpaired hydrology of 15 major watersheds in the western Sierra Nevada. SIERRA spans the same geographic region, uses the same set of climate change scenarios (+0°C, 2°C, 4°C, and 6°C warming), and the same temporal resolution (weekly time steps) as the WEAP-based hydrologic model. Mehta et al. (2011) developed a water management simulation model using WEAP to study the effects of climate change on hydropower in the Cosumnes, American, Bear and Yuba River watersheds using the runoff results of Young et al. (2009). SIERRA modifies the work of Mehta et al. (2011) with improved simulation methods.

This study is an outcome-based vulnerability assessment. In an outcome-based vulnerability assessment, vulnerability is defined as the effect of climate change on the managed domain of interest (e.g., hydropower generation), as mediated by exposure, sensitivity to changes in exposure, and system adaptive capacity (California Natural Resources Agency 2009; O'Brien et al. 2007). In this study, which is a study of water management, the specific exposure units—variables that are directly sensitive to climate variables such as air temperature and precipitation—include runoff, evaporation from reservoirs, and operations decisions that depend directly on precipitation or runoff.

Sensitivity of hydropower generation to climate changes is measured by system behavior at discrete levels of regional climate change. The study was conducted primarily using a hydrologic model results that approximates future climate conditions with uniform increases in air temperature. In addition, sensitivity to changes using a hydrologic model applied with downscaled climate data from general circulation model (GCMs) is considered. The details of these climate exposures are discussed in further detail. System adaptive capacity is not quantified explicitly, though many infrastructure operating rules in the model are inherently adaptive. For example, methods used to minimize spill from reservoirs enable some adaptation to warming-induced changes in runoff timing.

Section 3: Background

3.1. Water Resources in the Sierra Nevada

Water infrastructure in the upper Sierra Nevada, at elevations above about 300 m (1000 ft), is managed primarily for hydropower. Some high-elevation infrastructure is also managed explicitly for local and regional water supply, recreation, and flood regulation. High elevation water systems also have implicit water supply and flood regulation roles at the watershed scale by providing inflows to the major water projects of the Central Valley and by providing incidental flood storage space at the watershed scale(e.g., Hickey et al. 2003).

In California, hydropower generation supplies about 15 percent of the total electricity production. Hydropower systems in the Sierra Nevada provide roughly 75 percent of California's in-state hydropower, approximately 20,000 GWh annually, primarily from more than 150 reservoirs higher than 350 m above sea level (Aspen Environmental Group and M Cubed 2005).

3.2 Regional Climate Warming

Global climate warming will alter hydrology on global, regional, and local scales (Bates et al. 2008). Climate warming is expected to reduce snowpack, decrease mean annual flow, and lead to earlier spring snowmelt runoff in the western United States, including the Sierra Nevada (Dettinger et al. 2004; Hayhoe et al. 2004; Tanaka et al. 2006; Vicuna et al. 2007).

Hydrologic changes will affect hydropower production, urban and agricultural supply, recreation and other beneficial uses such as aquatic and terrestrial ecosystems (Hayhoe et al. 2004; Madani and Lund 2010; Medellín-Azuara et al. 2008; Null et al. 2010; Tanaka et al. 2006). While it is widely understood that warming will affect hydrology-dependent systems in the Sierra Nevada, few models quantify specific effects. These models are discussed below.

3.3 Regional Water Resources Management Models

Several water resources management models exist that include some aspect of watershed-scale water resources in the upper Sierra Nevada. All models of upper Sierra Nevada water systems are single-purpose (i.e., flood control, hydropower, and water resources. Existing models that include most of the upper Sierra Nevada are temporally coarse, generally monthly-scale, and also single-purpose. Some local models have greater temporal resolution (e.g., Vicuna et al. 2008). Models of California's major water supply systems such as CALVIN (Medellín-Azuara et al. 2008; Tanaka et al. 2006) and CalSim II (Draper and Darabzand 2003) exclude most high-elevation water systems above the large, low-elevation, multi-purpose reservoirs, yet rely on runoff from the Sierra Nevada as boundary inflows.

Two single-purpose reservoir management models have been developed that span most of the western Sierra Nevada. Hickey et al. (2003) included 73 flood reduction reservoirs, including 40 high-elevation Sierra Nevada reservoirs, in a *HEC-5*(U.S. Army Corps of Engineers (USACE) 1998) synthetic flood hydrograph simulation model for California's Central Valley. Madani and Lund (2009) modeled monthly hydropower generation in

California for elevations higher than 300 m (1000 ft), including most hydropower reservoirs in the Sierra Nevada, by describing reservoir storage in energy units and using the Energy-Based Hydropower Optimization Method (EBHOM) and assuming no annual spill. As these models are tailored to addressing specific water use purposes, they do not enable estimating regulated flows in specific locations.

Numerous models have been developed for operations planning for individual watersheds or systems in the western Sierra Nevada for flood control, hydropower, and water supply. For instance, the Pacific Gas & Electric Company (PG&E) uses an optimization model that incorporates probabilistic inflows to help plan operations of its hydropower systems (Jacobs et al. 1995), which span a substantial portion of the western Sierra Nevada.

Several models have been developed to study potential impacts of climate change on hydropower systems with local case studies (Mehta et al. 2011; Vicuna et al. 2009; Vicuna et al. 2008) and to study broad impacts across the Sierra Nevada at the monthly scale (Madani and Lund 2010). Using a range of downscaled climate conditions from two emissions and six general circulation model (GCM) scenarios, Vicuna et al. (2009) estimated decreases in energy production of 12.2 percent in the Upper American River Project (UARP) system and 10.4 percent in the Big Creek System (San Joaquin River watershed) by end-of-century, when averaged across emissions and GCM scenarios. These results are from corresponding decreases in mean annual runoff of 10.1 percent in the UARP system and 17.8 percent in the Big Creek System.

Mehta et al. (2011) developed a weekly scale model of the Cosumnes, American, Bear, and Yuba (CABY) watersheds in the western Sierra Nevada using the Water Evaluation and Planning system (WEAP) (Yates et al. 2005) to simulate changes in water management with regional climate warming. Assuming uniform air temperature increase of 0°C, 2°C, 4°C, and 6°C, as described by Young et al. (2009), they estimated a decrease in hydropower generation of almost 20 percent in the Yuba-Bear/Drum-Spaulding project in the upper Yuba River and Bear River watersheds and of 22 percent in the Middle Fork Project in the American River watershed. The model described here builds on the work of Mehta et al. (2011).

At the state-wide scale, Madani and Lund (2010) applied EBHOM (Madani and Lund 2009) to estimate effects of warming, with wet, dry, and warming-only conditions, on high-elevation hydropower generation. With warming-only—i.e., a change in runoff timing to earlier in the year, but with no change in total annual runoff—Madani and Lund (2010) estimated a decrease in energy generation California-wide by a much more modest 1.3 percent using hydrology from 1985–1988. With drier conditions (less runoff), they estimated decreases of almost 20 percent.

These studies demonstrate that annual generation is much more positively dependent on total annual runoff than on changes in runoff timing and that by end-of-century, hydropower production will likely decrease substantially due to decreased average annual runoff. This is due to the ability of hydropower systems to adapt, at least partially, to changes in runoff timing. Most regional climate change adaptation models inherently adapt to changes in timing because they use optimization methods; it is therefore essential to incorporate system adaptive capacity in a rule-based simulation model.

These anticipated impacts on hydropower generally mean that changing climate conditions need to be considered in long term, regional planning of water resources in the Sierra Nevada, as water users will be under ever greater pressure to maintain services and revenues by continuing to operate in ways that potentially harm other water users, including the environment.

Previous studies are collectively limited in geographic scope, management domain, and/or temporal scope. The goal of this work was to fill some of these gaps by including most of the water management infrastructure in the western Sierra Nevada in multi-reservoir simulation model framework and by using a finer temporal resolution.

Section 4: Methods

The primary objective of this work was to create a model that simulates the operations of all major upper Sierra Nevada water management in a way that is sensitive to climate changes and that can be readily improved for future studies. The model scope and the physical characteristics and operational logic of modeled features are described.

4.1 Model Scope

The modeling goal was to simulate dominant operations of major water management infrastructure in the upper west slope of the Sierra Nevada, including reservoirs, hydropower, water supply, and environmental flows, with air temperature a primary variable for operations. Modeled watersheds include, from north to south, the Feather (FEA), Yuba/Bear (YUB), American/Cosumnes (AMR), Mokelumne (MOK), Calaveras (CAL), Stanislaus (STN), Tuolumne (TUO), Merced (MER), San Joaquin (SJN), Kings (KNG), Kaweah (KAW), Tule (TUL), and Kern (KRN) River watersheds (Figure 1). The American, Bear and Yuba (ABY) Rivers are modeled and analyzed together due to their low-elevation inter-basin transfers; there is no hydropower in the Cosumnes (part of "CABY"). Most major infrastructure above the large, low-elevation dams are included, as described below. The Cosumnes, Calaveras and Merced watersheds lack major regulating infrastructure above their terminal dams; these watersheds are modeled, but excluded from analyses.

SIERRA was developed and applied using weekly time steps. For this study, SIERRA uses inflow data from Water Year (WY) 1981–2000, as developed by Young et al. (2009) for baseline operations. This time span is useful because it includes a wide range of recent historical climatic and discharge conditions typical of the region, including an extended drought (1987–1992), the wettest year on record (1983), and the flood year of record (1997).

4.2 Infrastructure

SIERRA includes (Table 1) reservoirs, fixed head hydropower, variable head hydropower, supply demands, instream flow requirements, and conveyances. This includes most major infrastructure elements in each watershed above the large, low-elevation, multi-purpose "rim" dams, exclusive of most rim dams. Most rim reservoirs were excluded, due to the added complexity of modeling flood regulation and water deliveries to the Central Valley. Exceptions include Lake Isabella (KRN), New Bullards Bar Dam (YUB), and Camp Far West Reservoir (YUB). All reservoirs listed by the California Data Exchange Center (CDEC) and within the study area were included. Most small reservoirs such as diversion reservoirs and forebays are excluded, with some exceptions. A complete list of modeled infrastructure and their characteristics is included in Appendix A.

Most hydropower projects are fixed head powerhouses, including both high head powerhouses typical of the Sierra Nevada and run-of-river powerhouses below small reservoirs. There are also a few conventional, variable head powerhouses. Small, private hydropower plants were generally omitted, with the exception of Kanaka Power plant (Feather River watershed). The distinction between fixed head and variable head is important in WEAP.

Water supply demands were included where data were available or where a diversion for water supply clearly exists. Diversions in the Sierra Nevada for water supply are small relative to water supply (mostly irrigation) for the Central Valley. A few small water supply diversions are not parameterized pending further development.

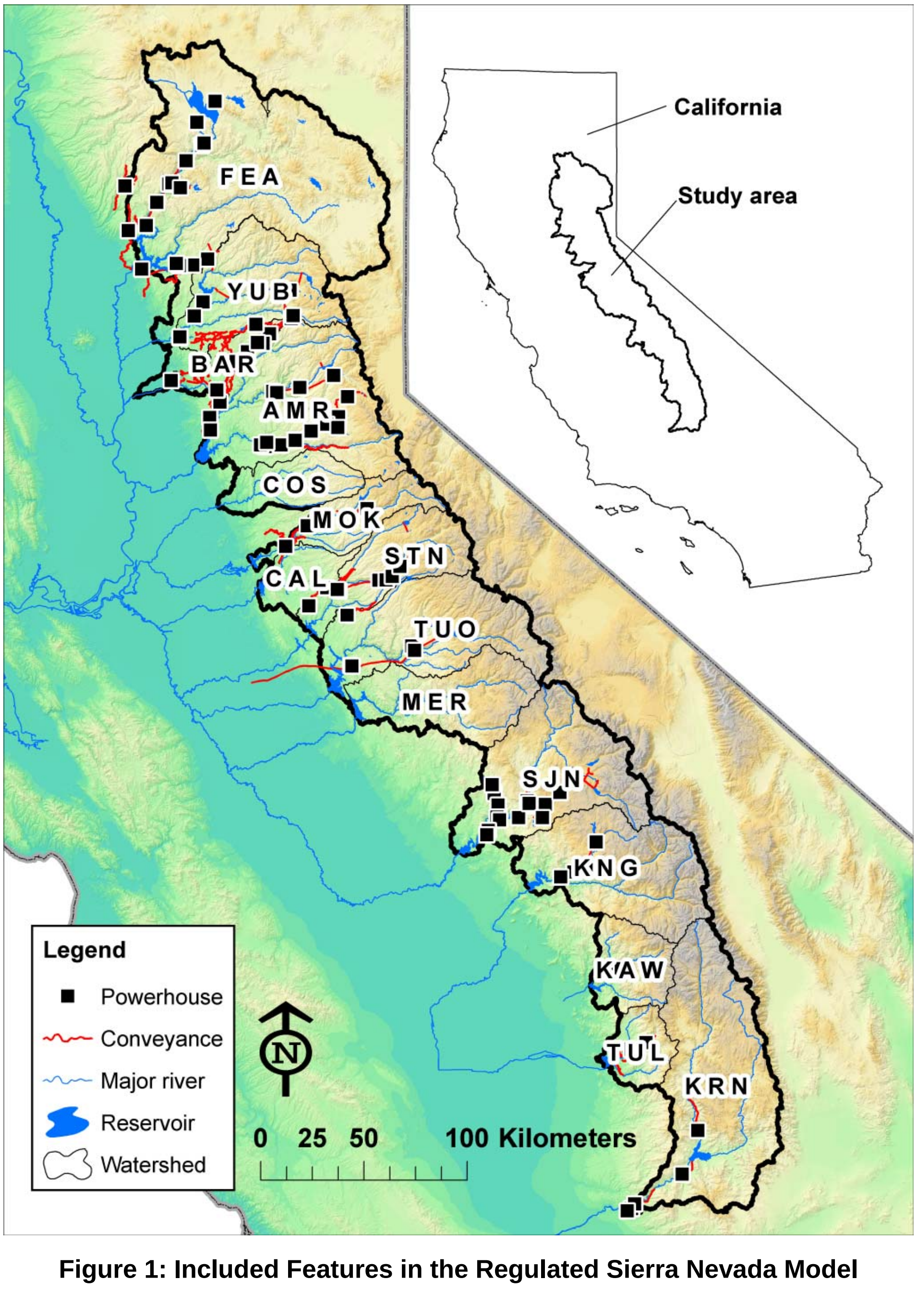

Figure 1: Included Features in the Regulated Sierra Nevada Model

Table 1: Count of Modeled Features in SIERRA (ordered north to south)

Model code	Watershed	Fixed head hydro	Variable head hydro	Reservoirs	Supply demands	Instream flow req't	Conveyance	Total
FEA	Feather River	16	2	10	3	18	20	**69**
ABY	Yuba River / Bear River	17	5	12	11	20	23	**88**
	American River	9	5	12	3	15	17	**61**
	Cosumnes River			1		1	1	**3**
MOK	Mokelumne River	4	1	2	2	7	9	**25**
CAL	Calaveras River							**0**
STN	Stanislaus River	8	2	6		11	12	**49**
TUO	Tuolumne River	3		3	1	3	6	**16**
MER	Merced River							**0**
SJN	San Joaquin River	15	1	8		19	21	**64**
KNG	Kings River	4		2		5	5	**16**
KAW	Kaweah River	3				4	5	**12**
TUL	Tule River	2			5	1	2	**10**
KRN	Kern River	5		1		5	5	**16**
		86	**16**	**58**	**25**	**109**	**126**	**419**

4.3 Water Evaluation and Planning System (WEAP)

SIERRA uses the Water Evaluation and Planning System (WEAP21 or WEAP) software. WEAP is a water resources modeling platform that integrates a two-soil layer, one-dimensional hydrologic model with a priority-based water resources management model (Yates et al. 2005). SIERRA uses WEAP's water management module, with runoff (inflow) represented as exogenous variables.

To simulate operations accurately, WEAP requires features and their physical parameters and operating rules, initial conditions, and boundary conditions (Figure 2). Operating rules represent the infrastructure management decisions for when and where to release water. In WEAP, these are provided as expressions, which vary from a single integer value to a call to an external script. Expressions can include mathematical operators, logical functions, and a range of built-in modeling functions. SIERRA relies on expressions to define input data and link to external lookup tables and scripts. Major inputs to the regulated model, including classes of modeled features and feature attributes, are listed in Table 2, with methods described below.

Climate change effects can be represented in SIERRA by changing boundary conditions, including meteorological conditions, which affect reservoir evaporation, and inflow time series. Climate change can also indirectly affect management in SIERRA through operating rules that depend on inflow and meteorology.

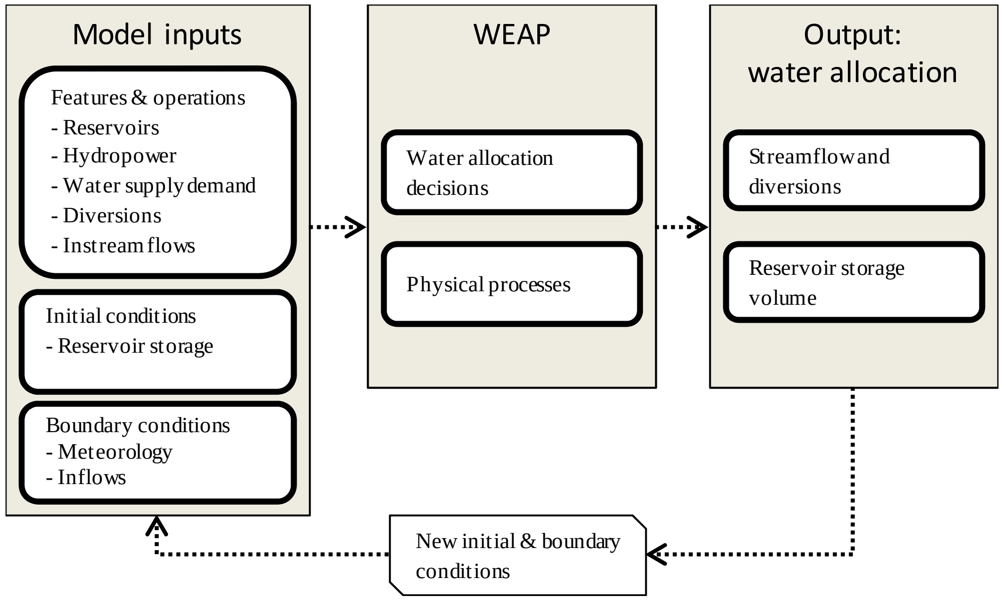

Figure 2: WEAP Model Process

Table 2: Modeled Features and Attributes

Feature	Model input attribute
Universal parameters	Water year indices Project-specific water year types
Reservoirs	Storage capacity Initial storage Volume-elevation curve Reservoir pool operations Storage priority Meteorological data for evaporation
Hydropower	Maximum turbine flow Generating efficiency Energy demand Energy priority
Water supply demand	Annual water use rate Weekly variation Water supply demand priority
Diversions	Maximum diversion
Instream flow requirements	Instream flow requirement ("IFR") IFR priority
Calibration gages	Stream flow data Reservoir data

4.4 Inflow Hydrology

SIERRA represents inflows as headwater flows in artificial tributaries to real river locations. The SIERRA model was originally designed to use the hydrologic model results of Young et al. (2009), described below. Artificial inflow tributaries are therefore coincident with the locations where Young et al. (2009) estimated runoff from subwatersheds. However, SIERRA can readily accommodate other inflow datasets.

Young et al.(2009) developed a weekly scale hydrologic simulation model of the western Sierra Nevada watersheds using WEAP, assuming no regulating infrastructure. WEAP uses a spatially explicit, one-dimensional, two-soil layer model, which simulates surface runoff and other hydrologic responses by explicitly accounting for overland flow, snow accumulation and melt, soil moisture storage, and evapotranspiration (Yates et al. 2005). Young et al. (2009) divided each watershed into subwatersheds, defined by locations—called "pour points"—of management interest or where there was sufficient observed data. They intersected each subwatershed with 250-meter (m) elevation bands, resulting in "catchments" that each have homogeneous physical characteristics such as meteorological conditions, soil conditions, and mix of land use cover.

Using weekly time steps, Young et al. (2009) modeled twenty-one water years (1980–2001) using interpolated Daymet climate data for historical precipitation, air temperature, and vapor pressure deficits. Watersheds were characterized using U.S. Geological Survey (USGS) 10 m digital elevation models (DEM), soil surveys from the Natural Resource Conservation Service (NRCS), and land cover from the USGS National Land Use Classification Database (NLCD). Simulated flows were calibrated at unregulated stream flow locations using data from USGS stream gages, and at some regulated sites using estimates of unimpaired hydrology from the California Department of Water Resources (DWR).

The unimpaired runoff models were calibrated for monthly flows at the outlets of 13 of the 15 watersheds—the Bear River and Calaveras River watersheds were omitted for lack of observed data—and for snow water equivalent (SWE) at 15 high-elevation locations (Young et al. 2009). This is an important consideration when assessing model results, which are sensitive to boundary inflows.

The model is also applied using runoff from a variable infiltration capacity (VIC) model. The VIC-based hydrologic model, described by Maurer et al. (2002), spans the North American continent and uses cells that span of 1/8° longitudinal and latitudinal dimensions. Variable infiltration capacity runoff is at the daily time step. Runoff from the VIC model was prepared for use in SIERRA by intersecting the 1/8° cells with WEAP subwatersheds using ArcGIS v9.3. Contributing VIC runoff was summed across intersected areas, weighted by proportion of intersected area to total subwatershed area. Daily runoff was aggregated to the weekly scale.

4.5 Universal Parameters

Universal parameters, called "key assumptions" in WEAP, can be used across the physical or management domain as primary or intermediary parameters to simplify expressions. For example, instream flow requirements often depend on a Water Year Type (WYT) that is regional in scope rather than associated with a single managed feature. A WYT defined as a key assumption can be used in operating rules for several instream flow requirement locations. Key assumptions are discussed as needed below, primarily for hydropower generation and instream flow requirements.

4.6 Reservoirs

Storage Capacity

Reservoir storage capacities were mostly obtained directly from the California Data Exchange Center (CDEC) and are listed in Appendix A.

Initial Storage

The beginning of the modeling period is October 1, 1980. Initial storage values were mostly from CDEC, but also from USGS gauges. Where only monthly reservoir storage data were available, storage values from October 1980 are used, as storage values from CDEC are for beginning-of-month. Where daily reservoir storage data were available, storage values from on October 1, 1980, were used. If historical storage was unavailable for October 1980, and a relationship between previous water year type and October storage was observed, then the average October storage for Wet water years on record was used, since Water Year 1980 was Wet under both the Sacramento and San Joaquin Valley Water Year Type definitions. If no relationship between water year type and October storage was apparent, then a simple average of storage levels for all Octobers on record was used, rounded to the nearest 100 AF.

Volume-Elevation Curves

Volume-elevation data for most reservoirs are from annual reservoir reports published by the U.S. Geological Survey. For reservoirs where such reports did not exist or did not include volume-elevation data, volume-elevation curves were created using a second-order polynomial fit using historical volume and elevation data reported by CDEC. Mountain Meadows Reservoir (North Fork Feather River) had neither a USGS report nor historical volume and elevation data from CDEC; a linear volume-elevation curve for this reservoir was assumed. Linear volume-elevation curves were also used for many small reservoirs.

Reservoir Zone Operations

Reservoir operations for recreation, water supply, and flood control are defined by setting requisite volumes for the inactive zone, buffer zone, and conservation zone of reservoirs ("zones" are also known as "pools").

Inactive zone – The inactive zone of a reservoir is the level, in elevation or storage, below which water cannot be withdrawn, for physical or operational reasons. An inactive zone storage volume was included for most reservoirs based on observed historical minimum levels.

Buffer zone – The buffer zone is the volume or elevation below which water allocations are curtailed, but not ceased. To help guide reservoir operations during the refill (wet season) period, an increasing buffer zone was defined in some reservoirs during a defined refill period.

Conservation and flood zones – The conservation zone is the volume available to store water above the inactive and buffer zones to meet downstream demand. A maximum conservation zone level, or rule curve, is used to create flood space in flood control reservoirs. Rule curves were included for New Bullards Bar Reservoir (North Fork Yuba River), and Lake Isabella (Kern River), though were not fully developed. Some non-flood control reservoirs were assigned conservation zone rule curves based on known operational objectives from public documents.

Lake Evaporation

A lake evaporation model using a modified form of the Penman equation as described by Dingman (2002) was applied to reservoirs. The Penman equation expresses lake evaporation as a function of:

- air temperature,
- incoming solar radiation,
- relative humidity,
- wind speed,
- cloudiness fraction,
- and reservoir surface area.

Each of the meteorological conditions (the first five inputs) is readily available from the hydrologic model of Young et al. (2009). We use meteorological data from the lowest catchment in the subwatershed contributing directly to the reservoir. In the unimpaired hydrologic model, air temperature is from Daymet; relative humidity is calculated from observed vapor pressure, which was from Daymet; average weekly wind speed is used; and a cloudiness factor of 1 is assumed. Solar radiation is calculated internally in WEAP. Reservoir area in one time step is derived from storage area at the end of the previous time step. We developed approximate volume-surface area relationships directly from volume-elevation relationships.

In real reservoirs, inflows and outflows transfer energy to/from the lake, affecting evaporation. We included neither of these transfers. We also assumed convective heat transfer to/from the ground via groundwater to be negligible.

4.7 Hydropower

The goal in this study was to model dominant operational characteristics of hydropower systems and to represent historical mean weekly and mean annual hydropower turbine flows. Two methods were used to define demand for hydropower. The first method, called the Water Year Index method (WYIM), is based on energy demand and is used to simulate historical reservoir releases to hydropower plants. The WYIM uses historical observations to approximate operating rules. The second method, called the "spill demand" method (SDM), is based on water demand rather than energy demand and is used to simulate the operating goal of operators to minimize spill, which usually represents lost revenue. Energy demand is modeled explicitly (WYIM) only for powerhouses that receive water directly from a large reservoir; all reservoirs, however, use the spill demand method (SDM). These two methods are described.

Water Year Index Method

Energy demand (E) for a powerhouse can be represented with an expression that includes percent (a) of energy generation capacity (E^{max}) as a key temporally variable parameter:

$$E_t = \alpha_t \cdot E^{max} \tag{0}$$

Energy generation capacity (E^{max}) is assumed constant in all high-head hydropower plants, such that:

$$E^{max} = \gamma \cdot h \cdot \eta \cdot Q^{max} \tag{0}$$

where γ is the specific weight of water, h is fixed hydropower head, η is plant efficiency (assumed 90 percent), and Q^{max} is the hydropower turbine flow capacity. The purpose of the energy demand modeling method is to define a_t. The Water Year Index method (WYIM) does this by relating weekly hydropower demand to annual water availability as a coarse approximation of actual demand.

Mehta et al.(2011) demonstrated that mean weekly hydropower operations can be adequately represented by establishing a relationship between water year type (WYT) and water demand for hydropower during any given week. For each week and each powerhouse, Mehta et al. (2011) used three regional water year types (dry, normal, and wet) and determined the respective non-exceedance percentiles of historical hydropower turbine for that week. A single non-exceedance percentile value was then chosen to specify a minimum diversion amount during simulation. For example, for a particular week, hydropower turbine flow demand might be the 10 percent non-exceedance value of historical flows for that week in dry years, 50 percent non-exceedance in normal years, and 90 percent non-exceedance in wet years. Mehta et al. (2011) adjusted these values during calibration.

The Water Year Index method (WYIM) modifies this approach. The WYIM assumes a continuous, linear response of turbine flow to regional water availability, as defined by a water year index, instead of the discrete, non-linear response to water year types of the CABY model.

For each week and each powerhouse, a linear relationship between water year index (WYI)—a continuous function of regional mean annual runoff—and hydropower turbine flow is established using historical observations. The equation parameters of the resulting linear fit—slope and intercept—are then used to determine hydropower turbine flow demand percent (a) given WYI:

$$\alpha_t = \frac{m_t \cdot WYI + b_t}{Q^{max}} \tag{0}$$

where m_t is the slope of the line, b_t is the intercept during week t for any given powerhouse, and Q^{max} is the maximum turbine capacity. In implementation, (5) is modified as needed to ensure that $0 \le a_t \le 1$.

The slope and intersect of Eq. (0) are readily determined from historical data and WYI for each powerhouse. For pumped storage facilities, which can have reverse flows, Eq. (0) is used without modification.

In the SIERRA model, the California Department of Water Resources (DWR) Sacramento Valley WYI was used for the northern watersheds (Feather through American) and the San Joaquin Valley WYI was used for the southern watersheds (Mokelumne through Kern). DWR WYIs are continuous and have units of million acre-feet (MAF) per year. The Sacramento Valley WYI is defined as:

> $WYI_{SacValley}$ = 0.4 * Current Apr-Jul Runoff Forecast (in MAF) + 0.3 * Current Oct-Mar Runoff in (MAF) + 0.3 * Previous Water Year's Index (if the Previous Water Year's Index exceeds 10.0, then 10.0 is used) (CDEC, 2010)

where "Runoff" is the sum of runoff from Sacramento River at Bend Bridge, Feather River inflow to Lake Oroville, Yuba River at Smartville, and American River inflow to Folsom Lake (CDEC 2010). The latter three can be computed directly from the unimpaired hydrologic models. To include the Sacramento River, we used a simple linear regression to correlate monthly flows in the Sacramento River at Bend Bridge with historical monthly Full Natural Flow (FNF) calculated by DWR for the Feather River. Using linear regression results, and assuming no change in relationship between the flows with warming, we calculated monthly Sacramento River flows for each climate warming scenario using simulated Feather River flows.

The San Joaquin WYI is defined as:

> $WYI_{SJValley}$ = 0.6 * Current Apr-Jul Runoff Forecast (in MAF) + 0.2 * Current Oct-Mar Runoff in (MAF) + 0.2 * Previous Water Year's Index (if the Previous Water Year's Index exceeds 4.5, then 4.5 is used) (CDEC 2010)

where "Runoff" is the sum of Stanislaus river inflow to New Melones reservoir, Tuolumne river inflow to New Don Pedro reservoir, Merced river inflow to Lake McClure, and San Joaquin river inflow to Millerton Lake, each of which is available from the unimpaired hydrologic models (CDEC 2010).

$WYI_{SacValley}$ and $WYI_{SJValley}$ are calculated for each atmospheric warming scenario using simulated runoff for the scenario. Since each WYI depends partly on WYI from the previous year, an initial WYI is required. To do this for warming scenarios, we established a linear regression between ΔT and WYT for each water year in the study period (i.e., WY 1981–2000). The slope of that linear relationship from a year with a WYI historically similar to that of WY 1980 was used to estimate WYI for WY 1980 for each warming scenario. Because initial rough estimates of WYI for WY 1980 were needed to determine the WYI-ΔT slopes, we excluded the first four Water Years from the slope calculations to eliminate the lag influence of WYI from one year to the next.

Figure 3 demonstrates this method, including its strengths and inherent limitations. Figure 3 shows relationships between the San Joaquin Valley WYI and hydropower turbine flow for Big Creek No. 1 powerhouse (San Joaquin watershed) for two weeks of the year: July 25–31 and November 7–13.As with most powerhouses, the linear relationship between WYI and turbine flow is stronger in wetter weeks when the reservoirs are full (e.g., July) and weaker during drier weeks, when reservoirs are empty (e.g., November). In wet weeks, hydropower and other uses can generally take as much as is available, even in drier years (Figure 3). During dry weeks, however, water users must be more selective about when they use water and base their decisions on many factors other than just water availability, such as wholesale electricity prices, prices of other energy sources, air temperature at load centers, hydropower operation type, and agreements with other users. Many of these factors are inherently stochastic in nature and not represented in the WYIM, resulting in the poor dry period fit in Fig. 3. Any hedging that occurs in the wet season will depend on water year type, which is generally proportionally related to weekly flow during the wet season, though not always.

The advantage of basing demand on a continuous water year index instead of a water year type, as used by Mehta et al. (2011), is greater sensitivity to changes in water availability, as measured by a water year index. This is consistent with hydropower operations being limited by real water availability rather than discrete water year type designations, even though some operational decisions may be affected by water year type (e.g., instream flow requirements). However, the continuous response function of the WYIM used here should not be a basis for assuming greater accuracy over the discrete method; The WYIM is comparable in model performance to that of Mehta et al.(2011).

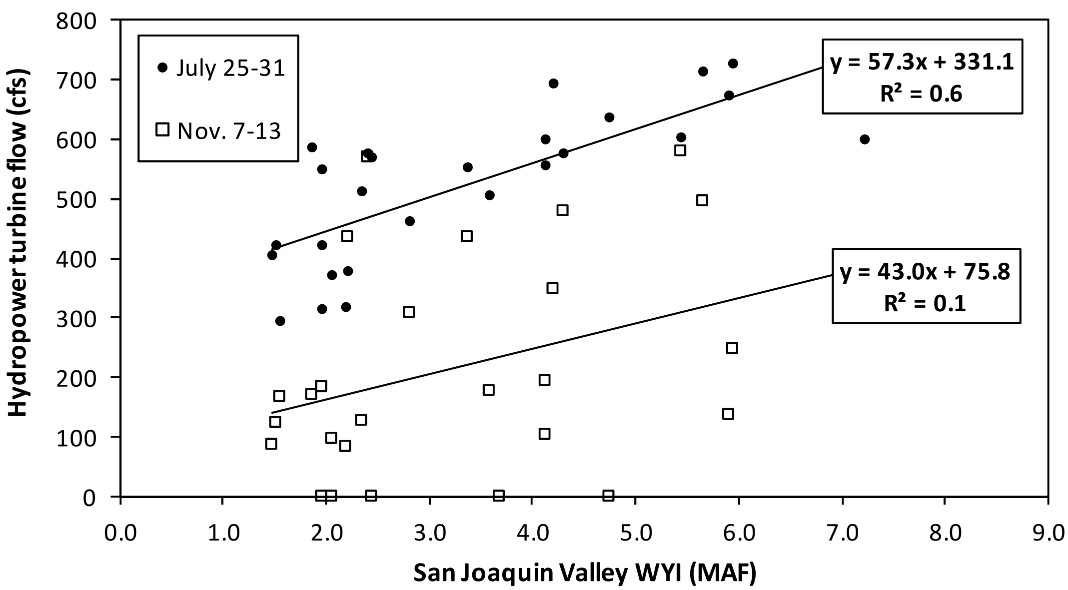

Figure 3: Historical San Joaquin Valley Water Year Index (WYI) and Big Creek No. 1 powerhouse turbine flow for the weeks of July 25–31 and November 7–13

The WYIM is fundamentally a time-series analysis approach to estimating energy demand. However, because the WYIM assumes perfect foresight of the WYI and, hence, total inflows, for the water year, it implicitly uses the pack rule (Bower et al. 1966), which minimizes spill by maximizing releases during a period given predicted inflows for the remainder of the drawdown-refill cycle and other system characteristics. The WYIM is ideally suited for rapid application to many powerhouses and adequately represents hydropower demand at coarse temporal scales. However, the method does not incorporate specific drivers of energy demand such as air temperature (Franco and Sanstad 2008); it is therefore is generally ill-suited for assessing energy characteristics at fine spatial and temporal resolutions. In general, this method and that of Mehta et al. (2011) are intended to estimate average abstractions for hydropower flows rather than simulate actual operations in any given week.

Another important inherent limitation in the WYIM is that the timing of energy demand timing is fixed, based on the historical timing of releases. However, the historical timing of releases is based, in part, on the historical timing of inflows. The WYIM fails to account for the change in timing of flows caused by warming. For the same total annual runoff, greater winter precipitation-driven runoff from warming causes more frequent spills in the winter using the WYIM. For a given WYI, this method does not increase hydropower generation even if water is spilling. This is resolved with the spill demand method described below.

Spill Demand Method

To prevent hydropower demand at less than capacity when a reservoir is spilling, another hydropower operating rule is introduced, called the spill demand method (SDM). The SDM simply requires that any inflow in excess of existing demands be diverted to generate hydropower. This ensures that hydropower plants use, as much as possible, water that cannot be stored and that would otherwise spill. The SDM is expressed mathematically as:

$$Q_{sd} = Q_{in} - \left(S_{max} - S\right) - Q_{target} - \sum_{r} Q_r \qquad (0)$$

where Q_{sd} is the hydropower release in excess of the target release, Q_{in} is the inflow during the week, S_{max} is the reservoir capacity, S is the reservoir storage, Q_{target} is the target release to meet energy demand (e.g., as determined by the WYIM), and Q_r is release for all other purposes. Q_{sd} is constrained by $0 \le Q_{sd} \le (Q_{max} - Q_{target})$. This is similar to the pack rule (Bower et al. 1966), though the SDM minimizes spill during the current time step only, without consideration of future inflows. Implementing the SDM mathematically is challenging, since many of the independent variables (storage level, inflow, and releases) are not known until the water allocation problem of the current time step has already been solved. The SDM is applied in SIERRA with an additional demand of 100 percent of turbine flow capacity, with a demand priority lower than upstream facilities and other local uses, if any, including meeting energy demand using the WYIM.

The SDM is applied to all powerhouses to minimize spill, which is lost energy/revenue. There are three distinct situations where this method is useful for hydropower generation. First, this method is applied to hydropower plants that lack upstream storage (i.e., off-stream run-of-river plants), such as in the Kaweah and Tule watersheds. This rule ensures that the plant diverts as much as possible, constrained only by IFRs and facility capacities. Second, this method is applied to powerhouses operated in coordination with upstream facilities. In high-elevation hydropower systems, hydropower plants are typically configured as a series as high-head plants, with water diverted via artificial channels to maintain maximum head before release via a penstock. Lower elevation plants in such cases demand 100 percent of capacity, albeit with a lower priority than upstream facilities. This method will result in *de facto* coordinated operations. Finally, this method is applied to all peaking powerplants, with a hydropower priority lower than all other local priorities. This ensures that any spill—i.e., water not stored or purposefully released to meet multiple demands—is diverted for hydropower generation, within capacity limitations. The latter use of the SDM is particularly important when considering climate warming, as it guarantees that peaking facilities utilize any extra available water rather than limiting diversions to historical patterns.

4.8 Water Supply Demand

Water supply for urban and agriculture use is limited in most of the Sierra Nevada above the large low-elevation, multi-purpose reservoirs and is small relative to water supply for agriculture in the Central Valley. However, they can be important because they have a higher priority than hydropower generation and play a central role in some systems (e.g., the Hetch Hetchy system in the Tuolumne, among others). When water is scarcer in drier years or in warming scenarios, hydropower is reduced before water supply if there is a conflict.

Demands were generally fixed, regardless of water year type, based on historical mean weekly flows, using data provided by water agencies. A major exception is diversions for water supply to San Francisco from the Hetch Hetchy system (Tuolumne River watershed). Analysis of historical diversions to San Francisco indicated a strong negative correlation between San Joaquin Valley WYI and annual diversions to San Francisco. This trend was confirmed in a private conversation with the San Francisco Public Utilities Commission (SFPUC), who noted that the Raker Act of 1913, which governs the Hetch Hetchy system, requires SFPUC to prioritize local sources of water. Thus, in wetter years, demand for diversions from the Tuolumne River watershed decreases. The smallest demand modeled was the Crab-Aiken Ditch Co. in the Tule River watershed, with a maximum diversion of 6.5 cubic feet per second (cfs). Some other more substantial demands exist but are excluded for lack of sufficient understanding of diversion rules (e.g., water supplied by the Utica Power Authority from the Stanislaus River). A complete list of modeled water supply demand locations is included in Appendix A.

4.9 Instream Flow Requirements

Instream flow requirements (IFRs) in WEAP consist of minimum instream flows (MIFs) required below dams and diversions. We included all IFRs identified in Federal Energy Regulatory Commission (FERC) licenses or from other documents if the project was not regulated by FERC (e.g., the Hetch Hetchy system). We did not include pulse flows, which some projects require to flush sediment downstream, or releases for whitewater recreation.

Instream flow requirements range from a single fixed value to values that vary by month and by water year type. IFRs that vary by month require a day-to-week conversion for month beginning and end dates. In general, we converted 30-day months to 4 weeks and 31-day months to 5 weeks. Some IFRs depend on the current state of system variables other than water year type. For example the IFR below Hetch Hetchy reservoir depends on cumulative precipitation at O'Shaughnessy Dam until the month of July, when it depends on inflow to Hetch Hetchy Reservoir. For these IFRs we used values calculated in the previous time step to determine the appropriate IFR for the current time step. Appendix A lists all IFR locations.

We calculated water year types (WYT) as needed for development of IFR expressions using simulated unimpaired flows from the inflow datasets. Water year type definitions are usually specific to a given hydroelectric project. Definitions can further vary within a project, such as for different IFR locations within the project. Some operations may also use spatially broader water year types such as the Sacramento and San Joaquin Valley WYT. Since water year types mostly depend on streamflow and flows change with climate changes, climate change affects operations constrained by water year types.

All water year type definitions use a combination of year-to-date flows and flow forecasts for the remainder of the water year. IFRs below Hetch Hetchy additionally depend on accumulated precipitation. For expediency, we computed water year types assuming perfect knowledge of the water year type using the unimpaired hydrology data, without forecasting. Future model improvements should include incorporating forecasting for water year type definitions and other operations.

4.10 Diversions

We included maximum diversion capacity for all diversions and assumed these to be constant over time. Maximum diversion values were obtained from a variety of publicly available documents, primarily hydropower license documents. When a maximum diversion was not available from a document, maximum flow from gage data was used. In many instances, maximum diversion values and maximum turbine flows were redundant. In the CABY region, the discrete minimum flow requirement method implemented by Mehta et al.(2011)was retained for diversions not directly leading to a hydropower plant. A list of all diversions is included in Appendix A.

4.11 Priority Setting

Correctly setting priorities is crucial for accurate results in priority-based water resources management models. In WEAP, priorities are assigned to all water management purposes, including for instream flow requirements, water supply, hydropower, and reservoirs. Priorities can range from 1 to 99, where 1 represents the highest priority. We assigned priorities to each feature based on (1) location of the feature in relation to other features and (2) the feature type, with modifications as needed. We did this by developing a two-digit priority scheme, where the first digit is based on the feature's location and the second digit based on the feature type. Feature locations were generalized by grouping them by hydropower or other development project. Upstream features/projects were assigned higher priorities (lower numbers), while downstream features/projects were assigned lower priorities. Without this upstream/downstream priority assignment scheme, the model allocates water to downstream users with high priorities (e.g., a utility district) instead of allowing a lower priority upstream user to use the water first.

Features were assigned priorities based on general water rights priorities:

1. Instream flow requirements
2. Water supply demand
3. Hydropower
4. Reservoirs

Hydropower facilities immediately below a reservoir, which used the WYIM to establish fixed energy demand, were assigned a priority equal to the reservoir. This worked because demand was based on historical observations. However, lower elevation hydropower plants in the same hydropower chain received a lower priority, as discussed above. Table 3 shows priorities for a hypothetical two-project system with each feature type represented in each project. Since allocating water among different potential uses is fundamentally driven by priority, the model is generally more sensitive to priorities than any other model parameter. Though this scheme works generally, in practice each water system is unique, necessitating a more detailed assessment of local priorities for future model improvements. Some priorities were adjusted as needed during model calibration. In particular, some reservoirs were assigned a higher priority during the refill period and a lower priority during the drawdown period.

Table 3: Priority Assignments for Two Hypothetical Projects

Water use type	*Project location / priority*	
	Upstream	*Downstream*
Instream flow req't	11	21
Water supply demand	13	23
Hydropower – WYIM	15	25
Hydropower – SDM	19	29
Reservoir storage	15	25

4.12 Interbasin Transfers

We modeled interbasin transfers differently on a case-by-case basis. Generally, an interbasin transfer is simulated in only one of the two watersheds that the transfer saddles, integrating the transfer into the watershed to which the transfer project belongs. In the watershed that does not dominate in the project, inflows to or outflows from that project are assumed based on historical or other modeled data. Several small interbasin transfers were omitted from the model for simplification (e.g., diversions from the Stanislaus to the Calaveras River watersheds).

Since the CABY watersheds are integrated into one model, intra-CABY transfers did not need special consideration. Transfers that did require special consideration include:

Yuba watershed to Feather watershed – Slate Creek provides water to the South Fork Feather River project for hydropower and water supply. The transfer was simulated in the Feather watershed model. Simulated transfers were included as a fixed weekly demand from Slate Creek in the CABY sub-model.

Stanislaus watershed to Tuolumne watershed – Flows from the Stanislaus watershed to the Tuolumne watershed via Phoenix powerhouse are included in the Stanislaus model.

4.13 Integrating Models and Data Management

A significant challenge in developing the model described here was to integrate 12 independent WEAP-based models with multiple climate scenarios for ease in execution, uniformity in output, and rapid results assessment and analysis. We used the Python scripting language to develop a suite of tools to address these needs. These tools can be readily adapted, if needed, and used to easily execute the model with alternative climate warming or other scenarios.

4.14 Climate Change Scenarios

To assess the vulnerability of upper Sierra Nevada water systems to climate warming—with inflow as the primary exposure unit—SIERRA was applied using inflow datasets from two different unimpaired hydrology studies to represent historical-, near-, mid-, and far-term climate conditions (Table 4). The first dataset is from Young et al. (2009), who applied their WEAP hydrologic model with spatially and temporally uniform increases in air temperature of 0°C, 2°C, 4°C, and 6°C and no change in precipitation magnitude or timing. These temperature increases broadly represent anticipated changes in the regional climate over the next 50–100 years, approximating temperature changes from the historical- through far-term (Table 5). Historical precipitation was assumed by Young et al. (2009) because downscaled general circulation models (GCMs) are less consistent in their prediction of changes in magnitude or timing of precipitation in California(Hayhoe et al. 2004).

The second dataset is from a variable infiltration capacity (VIC) hydrologic model for the United States (Maurer et al. 2002). The VIC model was applied using two emissions scenarios (B1 and A2) and the following downscaled climate data from six general circulation models (GCMs): CNRMCM3, GFDLCM21, MIROC32MED, MPIECHAM5, NCARCCSM3, and NCARPCM1. However, CNRMCM3 was omitted due to modeling difficulties with results from this particular dataset, reducing the GCM count to five. In this study, we considered the A2 emissions scenario and all six GCM results. Historical- through far-term climate conditions are represented with different time spans, as indicated in Table 1.

As noted above, historical runoff from the VIC model was found to be unusually high (Rheinheimer et al. 2011). However, derived from downscaled GCMs, the high historical runoff did not affect the climate change vulnerability assessment described here, as vulnerability to climate change was assessed with different precipitation values. Of greater importance here is that in contrast to the WEAP model, the VIC model was not calibrated for the Sierra Nevada. Pending any calibration of the VIC model for the Sierra Nevada, results using the VIC runoff data are of interest for average trends.

Table 4: Representation of Historical and Future Climate Conditions

Time period	I. WEAP runoff scenario	II. VIC runoff scenario
Historical	+0°C	1961–1990
Near-term	+2°C	2005–2034
Mid-term	+4°C	2035–2064
Far-term	+6°C	2070–2099

Section 5: Calibration and Model Assessment

The parameters and operating rules used in SIERRA were fixed, based on historical observations, so a formal calibration was generally not required. However, priorities, which were assigned initial values as discussed above, required adjustment in some instances to mimic observed system behavior. This was particularly true in cases for reservoirs in series or parallel in complex systems. Also, we observed that relative priorities can change seasonally in some such systems. Calibration was therefore limited to adjusting relative priorities as needed to ensure that reservoirs operated relative to each other as close as possible to observed operations. No adjustments were made to the inflow hydrology dataset. Model improvements for specific systems will require adjusting the physical parameters of the hydrologic model and contacting system operators to better understand and represent operational logic and operating priorities.

Here, we assess model performance using the WEAP-based unimpaired hydrologic model of Young et al. (2009), which was developed specifically for the Sierra Nevada. The VIC hydrologic model (Maurer et al. 2002), which was used for some climate change impact assessments as described below, was not specifically calibrated for the Sierra Nevada and showed a substantial over-estimation of regional runoff compared with the WEAP-based model (Rheinheimer et al. 2011). The historical runoff from the VIC model was therefore unsuitable for use in model performance assessments. Most (86 percent) of the noted discrepancies between historical runoff from the WEAP and VIC models were explained by the unusually high precipitation values in the VIC model.

To assess performance of the model, we focus on powerhouse turbine flow and reservoir storage, as these operations are the most challenging to simulate accurately and because meaningful characterizations of alterations to the natural flow regime—a long term goal—depend on a good understanding of simulation accuracy. Because modeled system behavior is sensitive to the hydrologic model, which was calibrated for flows at the watershed outlets and for snow water equivalent at only 15 high-locations model performance assessments are only considered in the context of watershed-scale or range-scale operations. Limiting model performance assessments to specific facilities is only appropriate with further calibration of the hydrologic model.

To assess model performance, we calculated the following metrics for hydropower turbine flow:

- Nash-Sutcliffe model efficiency (NSME) at the seasonal and annual scales
- Root mean square error (RMSE) at the seasonal and annual scales
- Mean bias

We also compare mean total and mean seasonal observed and simulated hydropower turbine flow, energy generation, and reservoir storage as points in a scatter plot at the range and watershed scales.

The Nash-Sutcliffe model efficiency index *NSME*(Nash and Sutcliffe 1980), also called the coefficient of determination (R^2) in other contexts, is often used in hydrology studies to compare modeled flows to observations. Though useful, *NSME* alone is not a reliable metric of model predictive power, as discussed by Jain and Sudheer (2008).*NSME* is defined as:

$$NSME = 1 - \frac{\sum_{t=1}^{T}\left(Q_{o,t} - Q_{m,t}\right)^2}{\sum_{t=1}^{T}\left(Q_{o,t} - \overline{Q_o}\right)^2} \tag{0}$$

where $Q_{o,t}$ and $Q_{m,t}$ are the observed and modeled flows, respectively, at time *t*, and *T* is the total number of observations. The Nash-Sutcliffe index describes the percentage of the variance that can be explained by the model. *E* can range from –∞ to 1. When *E* = 1, the model accurately predicts the observations; when *E* = 0, the model is no better or worse than the mean of the observations; when *E*< 0, the model is a worse predictor than the mean of the observations. Values typically become asymptotic as they approach 1 (perfect predictive power), thus large negative values should not be interpreted as equally nearing imperfection.

Root mean square error (*RMSE*) is a measure of the spread of the differences between observed and modeled data points. *RMSE* is defined as:

$$RMSE = \sqrt{\frac{1}{T} \cdot \sum_{t=1}^{T} (x_{m,t} - x_{o,t})^2} \tag{0}$$

where *t* is the time step and *T* is the total number of time steps. RMSE is always positive and smaller values indicate that modeled values are consistently closer to observed values. As with *NSME*, *RMSE* changes with time step length. Here, *RMSE* is normalized by dividing Eq. (5) by the mean observed flow, such that units are in percent.

Mean bias (*mBias*) quantifies the difference between the mean of modeled values and the mean of observed values:

$$mBias = \frac{1}{T} \cdot \left(\sum_{t=1}^{T} x_{m,t} - \sum_{t=1}^{T} x_{o,t} \right) \tag{0}$$

Mean bias can be either positive or negative; values closer to zero indicate greater model accuracy of mean modeled flows. As with *RMSE*, here mean bias is normalized to mean observed flow, resulting in percent units.

5.1 Hydropower Turbine Flow

Table 5 lists hydropower turbine flow model performance metrics at multiple temporal scales. 78 of the 86 fixed head hydropower plants are included in the performance assessment, as eight plants lacked sufficient observed data to make meaningful comparisons. At all temporal scales (weekly, seasonal, annual mean flow), approximately 60 percent of modeled plants have NSME values greater than zero, indicating most are better represented with the simulation model than with their historical mean flow. More than half have NSME values of 0.13, 0.18, and 0.31 at the weekly, seasonal, and annual scales, respectively (Table 5). Model simulation results improve with coarser units of analysis. The most well-modeled hydropower plants are also the ones with the greatest historical diversions (Figure 4) and the greatest hydropower generation. Conversely, the least well-modeled plants are smaller (Figure 4). Most plants under-represent hydropower turbine flow, with a median normalized mean bias of -12 percent. The mean normalized mean bias is approximately -10 percent. These results indicate that the more important hydropower plants are simulated well.

Table 5: Model Performance Metrics for Fixed Head Hydropower Turbine Flow

Percentile	Weekly NSME (%)	Seasonal NSME (%)	Annual NSME (%)	Seasonal RMSE (%)	Annual RMSE (%)	mean bias (%)
100% (maximum)	0.76	0.80	0.92	12.88	6.06	1.28
75%	0.38	0.50	0.63	3.27	1.21	0.00
50% (median)	0.13	0.18	0.31	2.56	0.88	-0.12
25%	-0.31	-0.55	-0.69	1.82	0.60	-0.23
0% (minimum)	-4.79	-7.79	-89.87	0.69	0.00	-0.70

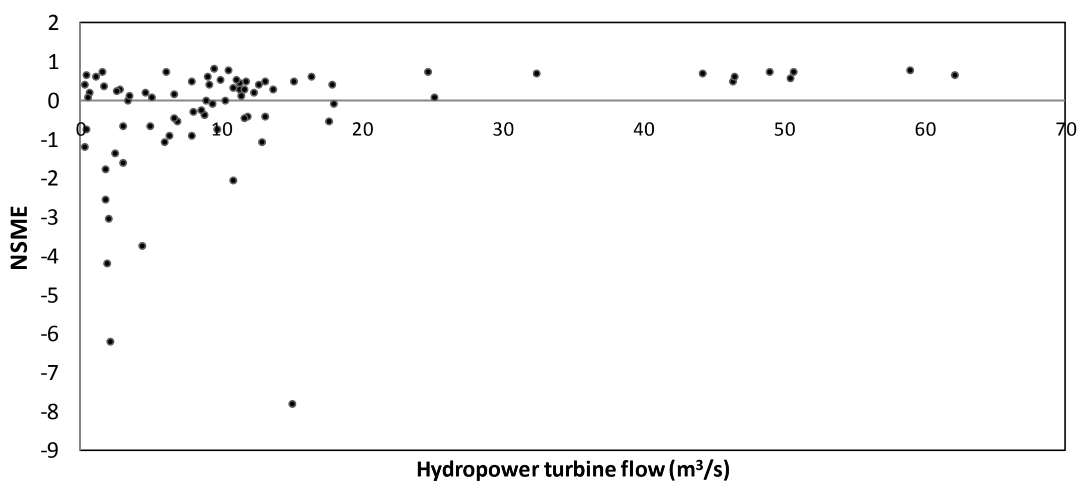

Figure 4: Seasonal NSME by Mean Modeled Turbine Flow

Figure 5 compares observed and modeled mean hydropower turbine flow in aggregate and by season (log scale). Each point in Figure 5 represents a single powerhouse. On average, mean hydropower flows match mean observed flows closely, though there is a tendency of the model to slightly under-predict flows, with a slope of 0.98 for mean annual flow. This is consistent with the negative mean bias noted above. The model tends to under-represent flows in the summer (July, August, September or JAS) and fall (October, November, December or OND), with modeled flows at 86 percent and 88 percent of observed flows, respectively. By contrast, flows are slightly over-represented in winter (January, February, March or JFM) and spring (April, May, June or AMJ), with modeled flows 103 percent and 112 percent of observed flows, respectively.

Similarly, Figure 6 compares observed and modeled mean hydropower generation in aggregate and by season. The model generally under-predicts hydropower generation, to a slightly greater degree than hydropower turbine flow. Figure 7 shows that the model effectively simulates historical total regional hydropower generation at the seasonal scale during the study period. However, consistent with the seasonal energy comparison results of Figure 6b, simulated energy is typically lower than observed during the summer, fall, and spring.

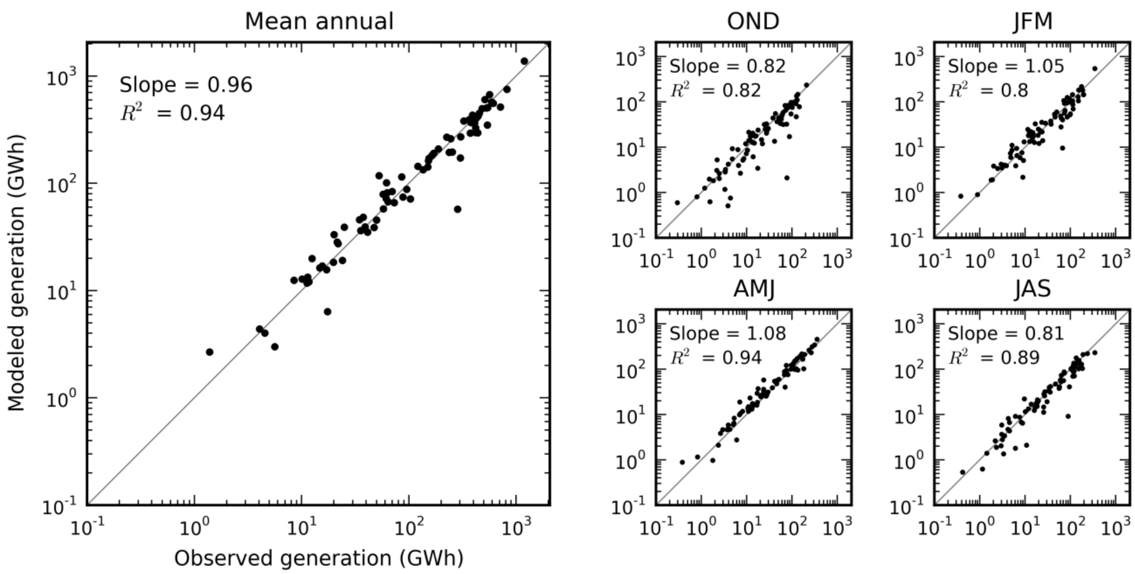

Figure 5: Observed and Modeled Mean Annual and Seasonal Hydropower Turbine Flow

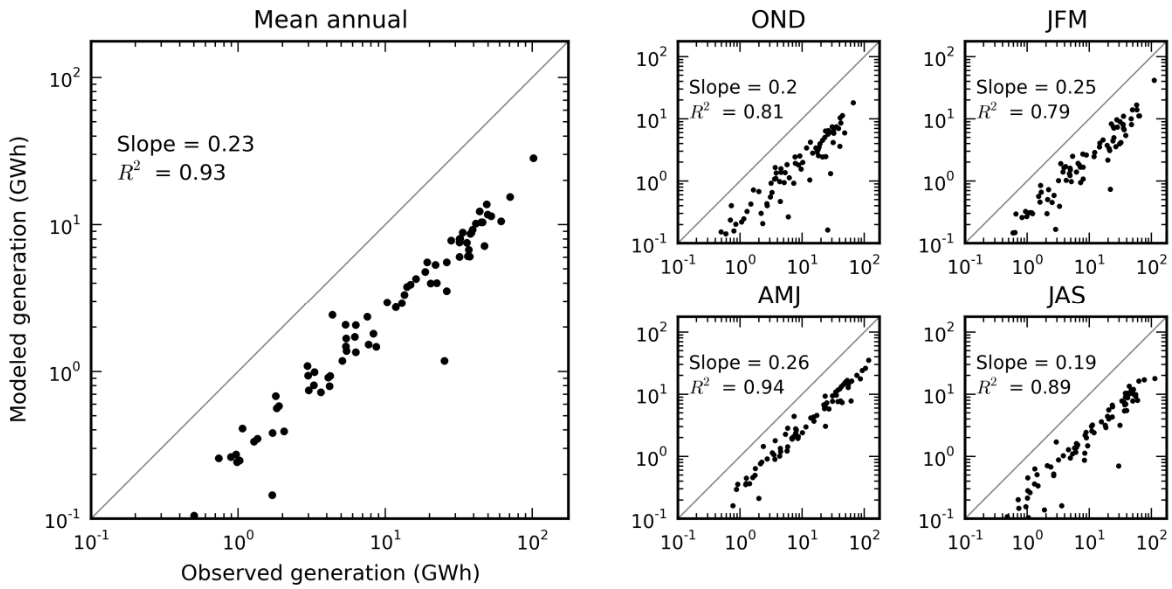

Figure 6: Observed and Simulated Mean Annual and Seasonal Hydropower Generation

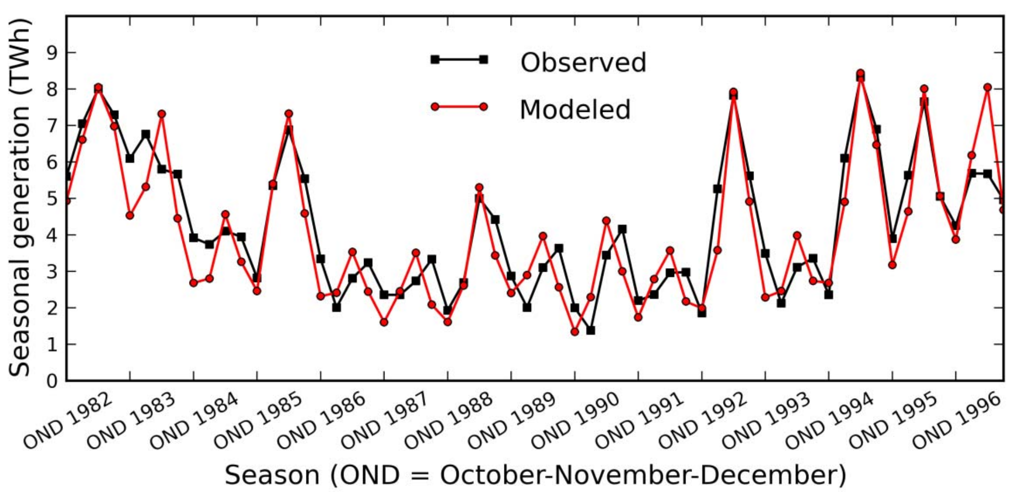

Figure 7: Total Observed and Modeled Hydropower Generation

These assessment results indicate that the model effectively represents observed hydropower turbine flow and generation patterns and that the model can be used to assess regional and weekly, seasonal or annual time step responses to changing external drivers such as inflow hydrology. Watershed-scale assessments can be made at the seasonal or annual scale. Change response assessments for specific facilities or systems are possible for approximately one-half of the systems in the Sierra Nevada. Further improvements are needed to more accurately represent specific facilities, particularly many smaller facilities. As the model is responsive to inflow hydrology, improvements in facility operations logic needs to be coupled with improvements in representation of inflow hydrology to better simulate historical operations.

5.2 Reservoir Storage and Evaporation

On average, modeled reservoir storage volumes (Figure 8) are generally modeled slightly more consistently well than hydropower flow or generation at both long term and by season. As with observed hydropower turbine flow, mean storage most closely matches observed values in the spring, when reservoirs are typically relatively full.

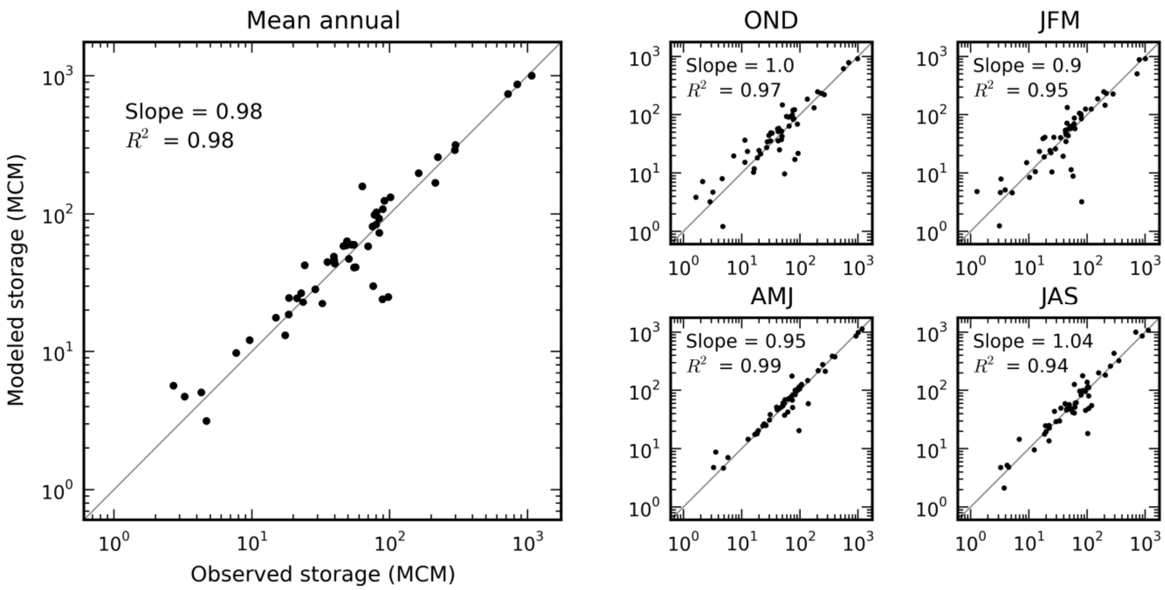

Figure 8: Observed and Modeled Mean Annual and Seasonal Reservoir Storage

The California Data Exchange Center does not typically report reservoir evaporation for high elevation reservoirs. One exception is Lake Almanor (Feather River watershed), for which "observed" monthly reservoir evaporation is estimated by using a constant pan evaporation coefficient of 0.7. To assess the lake evaporation model, we applied the model to Lake Almanor using observed reservoir storage. The model simulates the majority of the lake evaporation reported by CDEC, though tends to be lower than reported during late summer through winter and higher during spring and late summer (Figure 9).

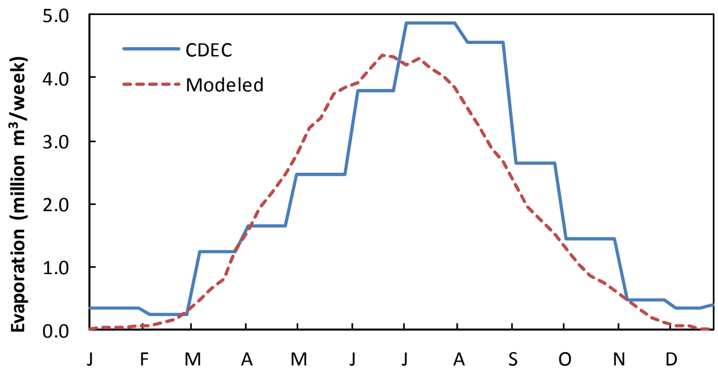

Figure 9: Mean (WY1981–2000) Mean Lake Evaporation for Lake Almanor Using Observed (CDEC) and Modeled Storage Data

Section 6: Results with Warming

Results from each of the runoff datasets used (WEAP and VIC), as described above, are discussed. Results from the WEAP model runoff are given much more detailed consideration, as the WEAP model was calibrated for the Sierra Nevada. General results are discussed for the VIC runoff scenario set. Using VIC runoff data, we performed basic quantitative assessments of results to identify the vulnerability (exposure) of hydropower generation on a system-wide and watershed basis.

6.1 WEAP Runoff Scenarios: Air Temperature Increase

Total Hydropower Generation

Trends at the weekly time step are important to understand coarser resolution trends. Figure 10 shows total mean weekly hydropower generation and generation changes with +0°C, 2°C, 4°C, and 6°C warming. Warming decreases the total regional mean weekly hydropower generation compared to the historical climate beginning in mid-April, when there is consistently very little change. Mean weekly generation decreases considerably thereafter—by about 40 percent in mid-June with 6°C warming—until late November. Mean weekly generation consistently increases between early December and mid-April, with a maximum increase of about 30 percent in late February with 6°C warming.

Sierra-wide seasonal changes are listed in
Table 6 and shown in Figure 11. Hydropower generation increases substantially during the winter, with equally great reductions in generation in the summer. Additional reductions in the other seasons cause a net reduction in mean annual hydropower generation. With 6°C warming, which represents possible end-of-century climate conditions, hydropower generation decreases by almost 1,500 GWh or 7.8 percent compared to historical climate conditions. These results are less than the results of others, discussed above. For example, Vicuna et al. (2009) estimated end-of-century generation losses of 12.2 percent and 10.4 percent for the Upper American River Project (American River) and Big Creek System (San Joaquin River), respectively. However, as discussed below, results for specific watersheds are substantially different from existing local studies.

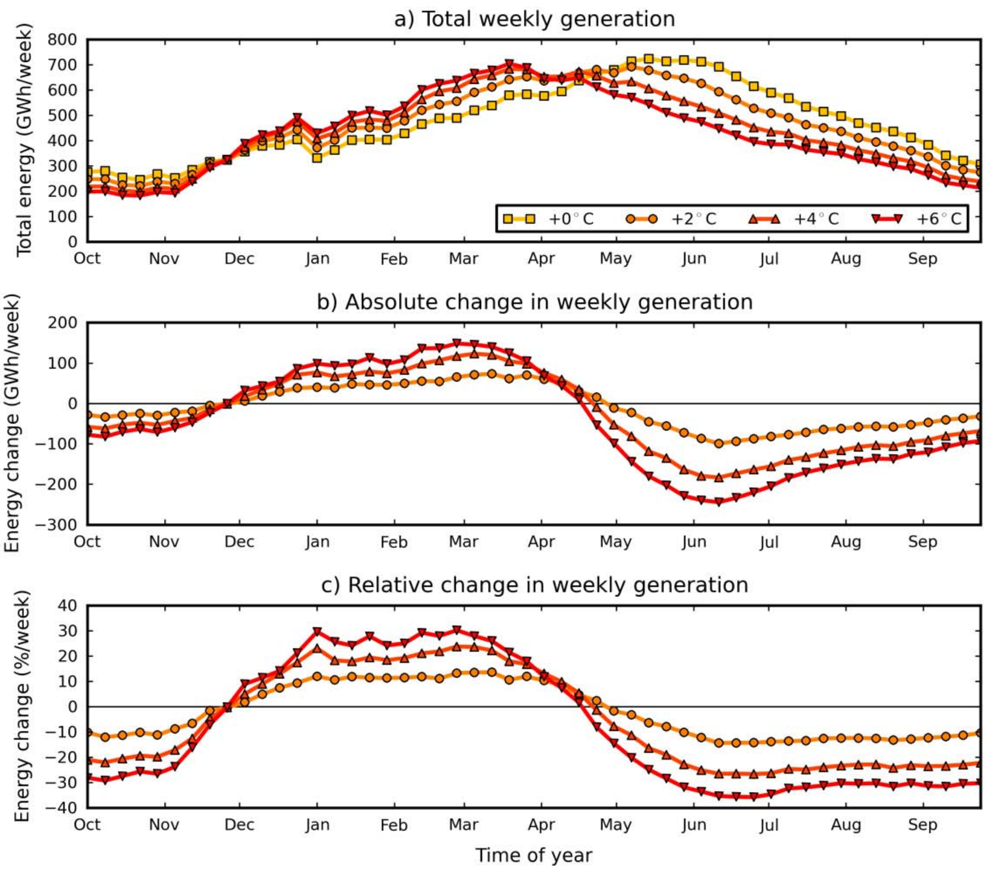

Figure 10: Mean Total Weekly Energy Generation with Warming

Table 6: Seasonal and Annual Hydropower Generation Change with Warming

Generation	Warming	OND (Fall)	JFM (Winter)	AMJ (Spring)	JAS (Summar)	*Annual*
Total (GWh)	+0 °C	3,104	4,331	6,701	4,734	*18,870*
	+2 °C	3,042	4,903	6,430	4,187	*18,561*
	+4 °C	2,974	5,323	5,983	3,690	*17,971*
	+6 °C	2,912	5,640	5,517	3,332	*17,401*
Change (GWh)	+0 °C	--	--	--	--	--
	+2 °C	-62	571	-270	-547	*-308*
	+4 °C	-130	992	-717	-1,044	*-899*
	+6 °C	-192	1,309	-1,184	-1,402	*-1,469*
Change (%)	+0 °C	--	--	--	--	--
	+2 °C	-2.0%	13.2%	-4.0%	-11.6%	*-1.6%*
	+4 °C	-4.2%	22.9%	-10.7%	-22.0%	*-4.8%*
	+6 °C	-6.2%	30.2%	-17.7%	-29.6%	*-7.8%*

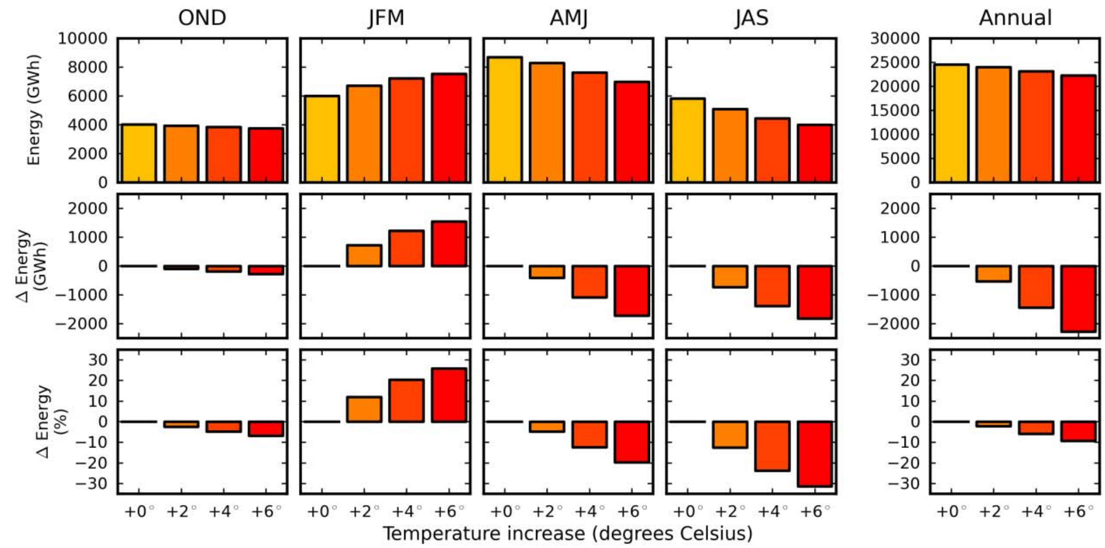

Figure 11: Seasonal and Annual Hydropower Generation with Warming

Hydropower Generation by Watershed

We also assess the effects of climate warming on hydropower generation for each watershed. At the watershed spatial scale, the seasonal temporal scale is the finest resolution appropriate given the limitations of the model. First, we note the seasonal shifts in hydropower generation with each warming scenario. Figure 12 shows seasonal changes in hydropower generation with warming for each watershed, whereas Figure 13 shows total annual changes in generation with warming, also per watershed; values from the base historical climate to 6°C warming are listed in
Table 7.

Whereas hydropower generation consistently decreases Sierra-wide in the summer months (JAS), hydropower generation increases relatively little in the northern watersheds (FEA and ABY watersheds). By contrast, hydropower appears to increase in central watersheds (STN, TUO, SJN, and KNG) during the wintertime. Central watersheds are therefore able to compensate for reductions in hydropower generation lost during the summer time by generating more during the winter months, when precipitation-driven runoff events are anticipated to dominate the hydrologic regime with warming. Mean annual hydropower generation substantially decreases in the highly productive northern watersheds in all warming scenarios. Generation in central watersheds change relatively little compared to the northern watersheds, and even increase somewhat with lesser warming. Generation trends with warming in the southern watersheds, which produce relatively little energy compared to northern and central watersheds, are somewhere in between: generation generally decreases, but magnitude decreases are small.

Several influences cause these trends with warming within and among watersheds: changes in runoff timing, changes in runoff magnitude, and infrastructure configuration/capacity. Additionally, model inputs and operational logic, including runoff data and priorities, affect system responses to change. Each influence is described, though a full sensitivity analysis was beyond the scope of this work.

First, throughout the Sierra Nevada there is less snowmelt-driven runoff in the late spring and early summer and greater precipitation-driven events in the winter. Even with no change in overall runoff, as this shift from snowmelt-driven events to earlier precipitation-driven events occurs, runoff becomes more evenly distributed throughout the year. Hydropower systems benefit from this increased uniformity in the near- and mid-term (+2 and 4°C) by being able to capture more incoming water, and spilling less. Thus, the timing of runoff has a major effect on system response to warming. Hydropower generation with greater warming (+6°C) is also influenced by changes in runoff timing, but in most cases changes in runoff magnitude dominate other influences. The combined effects of a shift to higher precipitation-driven events (high winter flows) and reduced total annual runoff results in greater earlier spill and reduces overall water available for hydropower generation. To benefit or minimize losses from changes in runoff timing and magnitude, however, the system has to be configured and operated to allow for flexibility in operations and there has to be enough existing under-utilized hydropower capacity in earlier weeks.

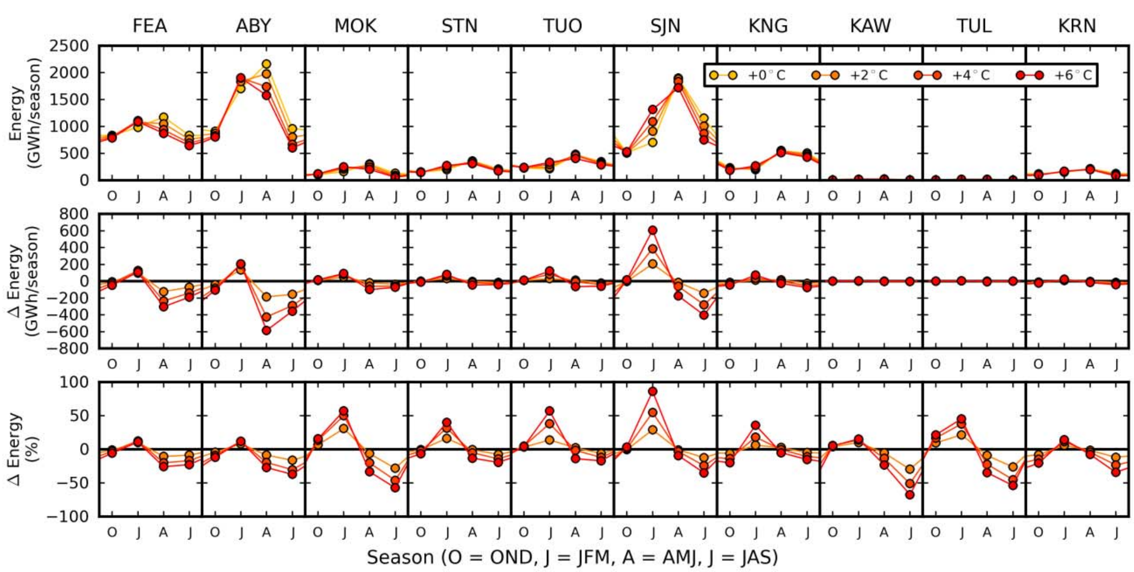

Figure 12: Seasonal Hydropower Generation Change by Watershed

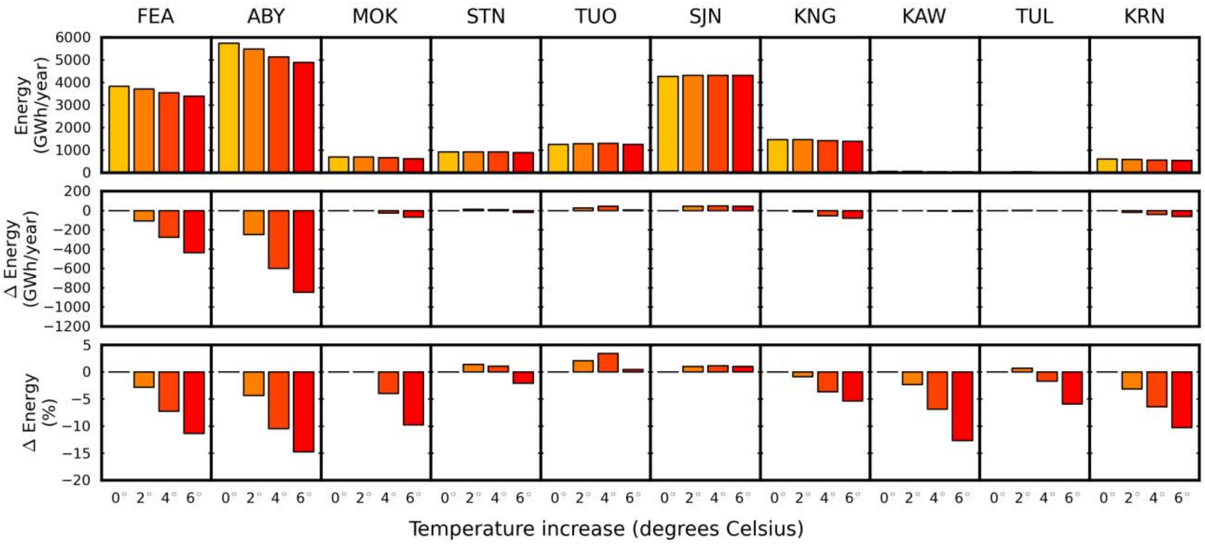

Figure 13: Mean Annual Hydropower Generation Change by Watershed

Table 7: Mean Annual Hydropower Generation Change with +6°C Warming by Watershed

Basin	+0 °C (GWh/year)	+6 °C (GWh/year)	Change (GWh/year)	Change (%)
FEA	3,827	3,392	-435	-11.4%
ABY	5,736	4,889	-847	-14.8%
MOK	693	625	-68	-9.7%
STN	918	899	-19	-2.1%
TUO	1,256	1,261	6	0.5%
SJN	4,267	4,311	44	1.0%
KNG	1,476	1,396	-79	-5.4%
KAW	55	48	-7	-12.7%
TUL	38	35	-2	-5.9%
KRN	605	543	-62	-10.3%
Total	*18,870*	*17,401*	*-1,469*	*-7.8%*

Finally, limitations of the model itself, including boundary conditions and operation logic, contribute to the observed trends in changes with warming for any particular system. The hydrologic model used was calibrated to watershed outlets and a few snow gauge locations (Young et al. 2009), resulting in poorly simulated runoff in some locations within watersheds. As hydropower systems divert water from specific locations within watersheds, the quality of inflow hydrology simulation at the subwatershed scale affects the quality of system responses to warming. Under-represented inflow to a reservoir, for example, could give that reservoir more capacity to be able to compensate for changes in runoff timing.

Though inflow hydrology is poorly represented in several locations, this did not appear to be a major cause of watershed-wide trends observed in Figures 12 and 13. Operational logic also affects system response to changing inflows, but was less of an issue than other influences.

The unique combination of each influence discussed above affects the response of any particular facility, system, or watershed to climate warming. Assuming the model is accurate, with correct operational logic and input data, the combination of system configuration, runoff magnitude, and runoff timing determine how the system behaves with historical climate and how the system responds to changes with warming. Thus, in the ABY region, substantial decreases in runoff magnitude dominate (Null et al. 2010), such that any existing additional capacity in regional systems is insufficient to substantially accommodate changes due to warming. By contrast, existing infrastructure configuration and capacity in the San Joaquin watershed, combined with minimal decreases in runoff magnitude (Null et al. 2010) with warming allows for minimal loss—gain, even—with warming. Specifically, Mammoth Pool Reservoir and powerhouse (San Joaquin River), which is historically well under capacity most of the year, can take advantage of a shift in runoff timing to reduce spill and increase generation in Mammoth Pool Reservoir. These watershed-specific trends, as reflected by spill—decreasing snowmelt spill in the American and San Joaquin watersheds with warming, yet increasing winter spill only in the American River watershed—were also noted by Vicuna et al.(2009).

Reservoir Storage

To account for climate warming-induced changes in the flow regime, with less precipitation stored as snowpack, we anticipate that reservoirs will be used to store more water, filling earlier. Simulation results reflect this, with a general shift in total, watershed-wide reservoir storage to earlier in the year, as shown in Figure 14. The peak of total storage in the Sierra Nevada shifts from early June to mid-April. Though the timing of reservoir storage changes to replace the storage role of diminishing snowpack, total system storage decreases. Storage changes from about 5.4×10^9 m^3 with a historical climate to about 5.2×10^9 m^3 with 6°C warming, a decrease of about 3.5 percent.

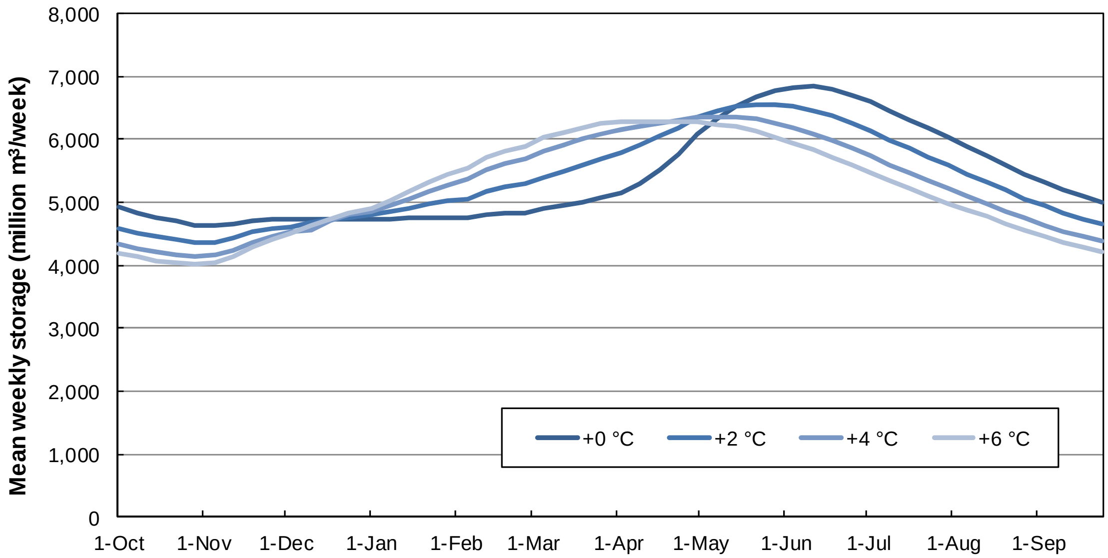

Figure 14: Total Sierra Nevada Storage for Modeled Reservoirs with Warming

While system-wide storage tends to decrease, the response of specific reservoirs to warming varies by reservoir size, reservoir operations, and changes in local runoff magnitude and timing. In all cases, peak reservoir storage shifts to earlier in the year. Magnitudes of mean reservoir storage changes are more variable. With 2°C warming, storage decreases in 60 percent of reservoirs compared to the historical climate. By 6°C warming, storage decreases in 68 percent of reservoirs. With near- and mid-term warming, the more uniform distribution of inflows results in a more uniform distribution of storage. With long-term warming, shorter duration, precipitation-driven runoff events dominate the flow regime, but total runoff magnitude decreases (Young et al. 2009; Null et al. 2010). Further analysis would elucidate whether reductions in storage are due to inability to capture high-magnitude events in the wintertime or from decreases in runoff magnitude. The magnitudes of total, systematic decreases in annual runoff magnitude with warming suggest that reductions are due to decreases in total annual runoff rather than changes in timing.

6.2 VIC Runoff Scenarios: Downscaled GCM Output

Hydropower Generation

Mean annual hydropower generation is consistently and substantially lower than WEAP runoff-based hydropower generation under all levels of climate change regionally (Table 8 and Figure 15) and for individual watersheds (Table 9). With historical climate conditions (1961–1990),**Error! Reference source not found.Error! Reference source not found.Error! Reference source not found.Error! Reference source not found.Error! Reference source not found.**mean annual generation system-wide ranges from 16,599 GWh to 18,890 GWh across all GCMs, with an average of 17,214 GWh. WEAP runoff-based mean annual hydropower generation was higher than this range with no warming, at 18,870 GWh (Table 6). This difference between VIC and WEAP runoff-based mean annual hydropower is amplified with far-term warming. With VIC runoff, mean annual hydropower generation decreases by 20.3 percent on average (Table 8), compared to only a 7.8 percent decrease with 6°C air temperature warming with the WEAP runoff. The main factor influencing total annual hydropower generation is total annual runoff, though timing of flows is also important. The VIC models use downscaled GCMs that consider changes in precipitation, which changes total runoff. Downscaled precipitation from the GCMs generally decreases with warming. In contrast, the WEAP model considers changes in air temperature only, with precipitation held at historical levels. These differences in precipitation magnitude changes account for much of the apparent differences between the two representations of climate change and model results. However, a more detailed analysis is needed to understand the differences with more specificity.

Changes in mean annual hydropower generation using the VIC hydrologic model with downscaled GCM climate data provide a useful indication of the range of possible changes in generation with regional climate warming through 2100. Mean annual hydropower generation decreases in the far-term by approximately 4.9 percent (NCARPCM1) to 36.2 percent (GFDLCM21), with an average decrease of 20.3percent (Table 8).

By watershed, changes range from -9.2 percent (Kern River watershed) to -28.8 percent (Kings River watershed) (Table 9). Hydropower generation consistently decreases in all watersheds and in most time periods, in contrast with the warming-only considered with the WEAP hydrologic model (Figure 13). The changes in hydropower generation by basin with the VIC runoff scenarios (Figure 9) do not generally match the changes observed with the WEAP runoff scenarios. This is to be expected, due to the differences in representations of regional climate change.

Table 8: Mean Annual Hydropower Generation (GWh) by GCM and Time Span with Percent Change from Historical Climate Conditions

Climate model	Historical (1961-1990)	Near-term (2005-2034)	Mid-term (2035-2064)	Far-term (2070-2099)
GFDLCM21	16,945	16,246	15,397	11,057
		-4.1%	*-9.1%*	*-34.7%*
MIROC32MED	17,005	14,792	11,597	11,022
		-13.0%	*-31.8%*	*-35.2%*
MPIECHAM5	18,457	15,883	15,044	16,579
		-13.9%	*-18.5%*	*-10.2%*
NCARCCSM3	16,881	15,394	14,515	13,962
		-8.8%	*-14.0%*	*-17.3%*
NCARPCM1	17,777	17,522	17,135	16,754
		-1.4%	*-3.6%*	*-5.8%*
Average	17,413	15,967	14,737	13,875
		-8.3%	*-15.4%*	*-20.3%*

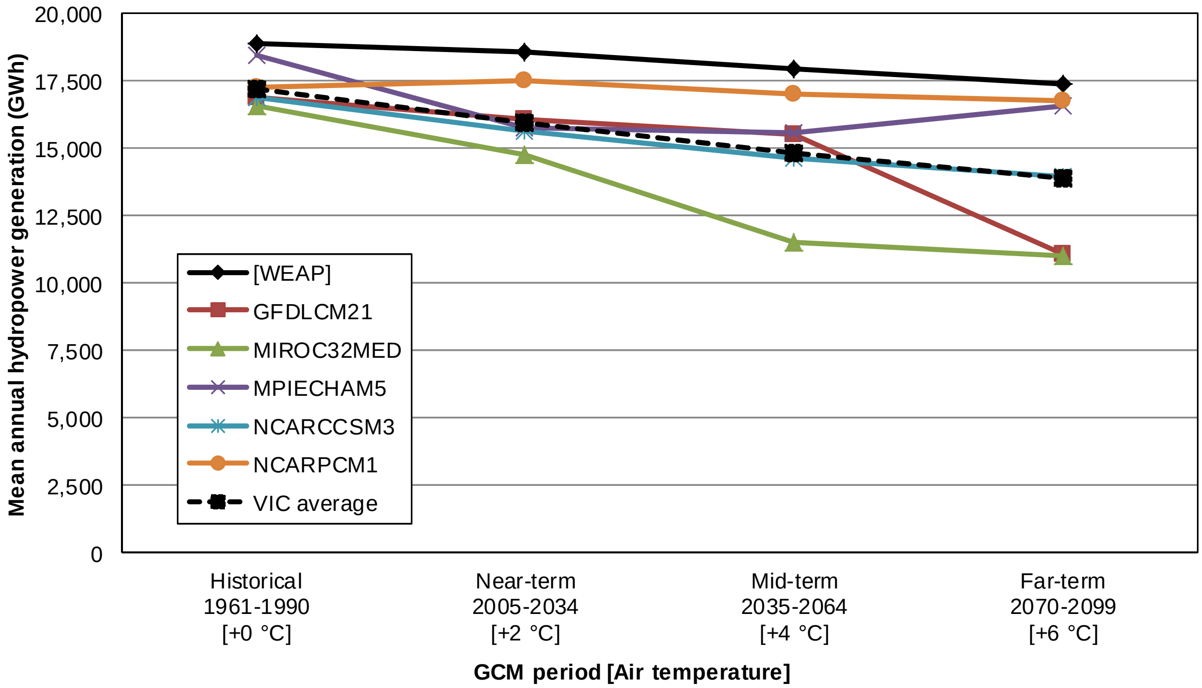

Figure 15: Mean Annual Hydropower Generation by Hydrologic and climate Model with Warming

Table 9: Mean Annual Hydropower Generation by Basin and Time Span with Mean, Range, and Percent Change from Historical Climate Conditions

Basin	Historical (1961-1990)	Near-term (2005-2034)	Mid-term (2035-2064)	Far-term (2070-2099)
FEA	3,037 (2,858 - 3,198)	2,707 (2,492 - 2,919) *-10.9%*	2,524 (2,150 - 2,875) *-16.9%*	2,342 (1,861 - 2,793) *-22.9%*
ABY	5,447 (5,208 - 5,728)	5,026 (4,636 - 5,419) *-7.7%*	4,693 (3,920 - 5,276) *-13.8%*	4,441 (3,679 - 5,208) *-18.5%*
MOK	587 (572 - 609)	540 (503 - 599) *-8.%*	501 (399 - 571) *-14.7%*	475 (385 - 568) *-19.1%*
STN	920 (896 - 962)	859 (804 - 930) *-6.6%*	794 (647 - 905) *-13.7%*	752 (621 - 880) *-18.3%*
TUO	1,199 (1,153 - 1,271)	1,120 (1,050 - 1,235) *-6.6%*	1,024 (784 - 1,191) *-14.6%*	970 (768 - 1,191) *-19.1%*
SJN	4,234 (3,950 - 4,547)	3,880 (3,568 - 4,360) *-8.4%*	3,518 (2,441 - 4,301) *-16.9%*	3,315 (2,298 - 4,235) *-21.7%*
KNG	1,132 (995 - 1,265)	1,002 (910 - 1,200) *-11.5%*	880 (518 - 1,165) *-22.3%*	806 (434 - 1,192) *-28.8%*
KAW	75 (73 - 77)	72 (70 - 74) *-4.%*	69 (64 - 73) *-8.%*	65 (59 - 71) *-13.3%*
TUL	48 (46 - 49)	45 (42 - 48) *-6.3%*	43 (37 - 46) *-10.4%*	41 (34 - 47) *-14.6%*
KRN	730 (713 - 747)	712 (692 - 734) *-2.5%*	688 (632 - 727) *-5.8%*	663 (594 - 719) *-9.2%*
Total	17,409 (16,464 - 18,453)	15,963 (14,767 - 17,518) *-8.3%*	14,734 (11,592 - 17,130) *-15.4%*	13,870 (10,733 - 16,904) *-20.3%*

Section 7: Limitations

Spatiotemporal scope – As with all models, the SIERRA model is a simplified representation of real systems. The spatiotemporal scope of the model—weekly time step operations for most major reservoirs, hydropower plants, diversions, and instream flow requirement locations—necessitates analyses across watersheds and at the seasonal and annual time steps. Many small dams and diversions are omitted from the model for simplification, such as forebays, afterbays, and small water users that divert, store, and use water; these are currently unaccounted for. The spatiotemporal scope also affects included operations, since some hydropower generation decisions are made at the daily, hourly or shorter time step. This would affect simulation accuracy even with improved weekly-scale hydropower operations logic.

Inflow hydrology – The hydrologic model accuracy is a major limitation of the model, as applied. Because the hydrologic model used (Young et al. 2009) was calibrated only to the watershed outlets and to snow water equivalent at only 15 locations, inflow hydrology is under-represented in some locations and over-represented in other locations. This affects hydropower operations that depend on accurate inflows in specific locations rather than only at the watershed outlets.

Climate warming scenarios – Another important limitation of the inflow hydrology used for climate warming scenarios (Young et al. 2009) is the use of uniform and homogeneous changes in air temperature instead of location- and time-specific changes. Additionally, historical precipitation is assumed. Because some downscaled GCMs predict increased precipitation, while others predict less, it is important to assess impacts of warm-dry and warm-wet scenarios, as done by others (e.g., Madani and Lund 2010; Vicuna et al. 2008).

Climate warming effects – In the SIERRA model, warming only affects physical hydrology and lake evaporation. However, climate warming will also affect other important parameters that hydrology and water management decisions depend on. For example, atmospheric warming will likely increase energy demand; this effect is not represented in the model.

Hydropower generation – Hydropower operations here operate to a rule, whereas most hydropower systems operate for profit, responding to energy prices. The Water Year Index method works well in the long term, but does not account for weekly scale fluctuations in hydropower operations from hydropeaking or week-to-week price variability due to weather patterns. An optimization method is needed to more accurately simulate operations of hydropeaking facilities. One option is to assume the distribution of energy prices is known during the hydropeaking period, such that the optimal operation policy is to release during every hour that the energy price is above a threshold. A second option worth exploring is to establish relationships between power generation and watershed characteristics other than streamflow. For example, in California energy demand during the summer correlates with air temperature, since air conditioners, turned on when air temperature is high, are a major energy consumer.

Flood control and rim dams –Operation of rim dams, which were outside the spatial domain of the model, can affect upstream operations. For example, the Hetch Hetchy system is operated partially in coordination with flood control operations at New Don Pedro reservoir.

Inclusion of rim dams and upstream flood control operations would enable a better understanding of flood risk and control, including the possibility of utilizing higher reservoirs for some flood control.

Water supply demands – Existing water supply demand is limited in two ways. First, included demands are based on historical observations or known supply requirements. Water management projections should also include anticipated changes in other factors that affect future water demand such as future population growth and water use patterns in different sectors. Second, many smaller abstractions within the spatial extent of the model have been excluded for simplification. Including more of the smaller water diversions would help improve overall model accuracy.

Uncertainty and sensitivity – We did not conduct an uncertainty or sensitivity analysis for this model. Although there are several theoretically robust methods to help map uncertainty in inputs to uncertainty in outputs, the methods require substantial amounts of computational power. An analysis of the most obvious sources of uncertainty, such as inflow hydrology, and an assessment of which parameters the model is most sensitive to would be beneficial.

Section 8: Conclusions

The model presented here (SIERRA) is one of the larger hydropower and montane water resources simulation models. The main contribution of this work is both the model itself, including the methods for simulating hydropower generation, albeit coarse, and the quantitative assessment of hydropower generation impacts of regional climate warming. SIERRA can be used to assess effects of regional climate warming on a wide range of managed water systems and beneficial uses of water in the Sierra Nevada. The model performs well for hydropower facilities in the region for assessments of change at the seasonal and annual time scales.

Though other studies estimate climate change effects on hydropower, they are either very broad or very specific. The work here bridges the gap between generalized, state-wide studies and specific, local studies. We applied SIERRA at the weekly scale using climate warming scenarios of +0°C, 2°C, 4°C, and 6°C warming. Hydropower generation decreases in all warming scenarios, driven primarily by decreases in the highly productive watersheds in the northern Sierra Nevada. With far-term warming (+6°C), model results suggest about an 8 percent decrease in mean annual hydropower generation within the study region. This is less than estimates from other studies that consider drier conditions (less precipitation and runoff), but greater than studies that consider warming only (no change in annual runoff). Results from a Variable Infiltration Capacity hydrologic model using climate data from five GCMs are also included. Decreases in hydropower generation are much greater with GCM climate data and VIC hydrology than with WEAP hydrology, which does not consider changes in precipitation.

The most substantial decreases in mean annual hydropower generation occur in the northern watersheds, which have large decreases in runoff magnitude. In contrast, the model generally predicts a slight increase in generation with near- and mid-term warming followed by a slight decrease in generation with far-term warming. The model predicts constant declines in hydropower generation in the southern watersheds, though total generation in southern watersheds is small. These results suggest that future struggles over water use will be relatively more pronounced in the northern watersheds.

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Glossary

ABY	American, Bear and Yuba Rivers
AMJ	April, May, June
AMR	American/Cosumnes River watersheds
CABY	Cosumnes, American, Bear, and Yuba River watersheds
CAL	Calaveras River watersheds
CDEC	California Data Exchange Center
DEM	digital elevation models
DWR	California Department of Water Resources
EBHOM	Energy-Based Hydropower Optimization Method
FEA	Feather River watersheds
FERC	Federal Energy Regulatory Commission
FNF	full natural flow
GCM	global circulation model
IFR	instream flow requirement
JAS	July, August, September
JFM	January, February, March
KAW	Kaweah River watersheds
KNG	Kings River watersheds
KRN	Kern River watersheds
MAF	million acre-feet

MER	Merced River watersheds
MIF	minimum instream flow
MOK	Mokelumne River watersheds
NLCD	National Land Use Classification Database
NRCS	Natural Resource Conservation Service
NSME	Nash-Sutcliffe model efficiency
OND	October, November, December
PG&E	Pacific Gas & Electric Company
RMSE	root mean square error
SDM	spill demand method
SFPUC	San Francisco Public Utilities Commission
SIERRA	Sierra Integrated Environmental and Regulated Rivers Assessment
SJN	San Joaquin River watersheds
STN	Stanislaus River watersheds
SWE	snow water equivalent
TUL	Tule River watersheds
TUO	Tuolumne River watersheds
UARP	Upper American River Project
USACE	U.S. Army Corps of Engineers
USGS	U.S. Geological Survey
VIC	variable infiltration capacity
WEAP	Water Evaluation and Planning
WYI	water year index
WYIM	water year index method
WYT	water year type
YUB	Yuba/Bear River watersheds

Appendix A: SIERRA Input Parameters

This Appendix includes the main physical and operations parameters used in SIERRA, including for reservoirs, run-of-river hydropower, variable head hydropower, water supply demand, instream flow requirements, and diversion conveyances. Some inconsistencies and conventions are worth noting. Source data units are usually in English units. However, WEAP uses SI units. In these tables, English units are mostly used, though some data are given in SI units.

Abbreviations and non-SI units in the tables are:

- mcm = million cubic meters (1.0×10^{6} m^3)
- 1 AF = 1 acre-foot = 1.233×10^{3} m^3
- 1 ft = 1 foot = 3.048×10^{-1} m
- 1 ft^3/s = $2.832\times10^{2} m^3/s$

Other abbreviations include:

- CDEC = California Data Exchange Center
- USGS = U.S. Geological Survey

Finally, we note again that the watersheds were grouped into mutually independent models (the latter are referred to in the main text), in order from north to south, as follows:

<table>
<tr><th>Watershed</th><th>Model abbr.</th><th>Watershed</th><th>Model abbr.</th></tr>
<tr><td>Feather</td><td>FEA</td><td>Tuolumne</td><td>TUO</td></tr>
<tr><td>Yuba</td><td rowspan="4">ABY</td><td>Merced</td><td>MER</td></tr>
<tr><td>Bear</td><td>San Joaquin</td><td>SJN</td></tr>
<tr><td>American</td><td>Kings</td><td>KNG</td></tr>
<tr><td>Cosumnes</td><td>Kaweah</td><td>KAW</td></tr>
<tr><td>Mokelumne</td><td>MOK</td><td>Tule</td><td>TUL</td></tr>
<tr><td>Calaveras</td><td>CAL</td><td>Kern</td><td>KRN</td></tr>
<tr><td>Stanislaus</td><td>STN</td><td></td><td></td></tr>
</table>

Table A-1. Reservoir Parameters

Watershed	Name	Storage capacity (AF)	Storage capacity (mcm)	Minimum storage (mcm)	Min elevation (m)	Max. elevation (m)	Refill priority	Drawdown priority	CDEC gauge	USGS gauge
American	Caples Lake	21.6	26.6	2.5	0.0	100.0	15	15	CPL	N/A
	Chili Bar Reservoir	3.1	3.9	0	0.0	18.3	55	55	N/A	N/A
	French Meadows Reservoir	136.4	168.2	61.7	0.0	100.0	15	15	FMD	N/A
	Hell Hole Reservoir	207.3	255.7	38.8 / 86.3	1306.0	1417.3	25	25	HHL	N/A
	Ice House Reservoir	46.0	56.7	17.3 – 53.6	1623.8	1670.3	15	15	ICH	11441100
	Loon Lake	76.5	94.3	0	1928.0	1959.9	15	15	LON	11429350
	Oxbow Reservoir	24.3	30.0	0	0.0	75.0	45	45	N/A	N/A
	Rubicon Reservoir	1.5	1.8	0	1981.2	1996.4	15	15	N/A	N/A
	Silver Lake	8.6	10.7	0.5	0.0	50.0	15	15	SIV	N/A
	Slab Creek Reservoir	16.6	20.5	12.3	512.1	570.0	45	45	SLB	11443450
	Stumpy Meadows Reservoir	20.0	24.7	0	0.0	100.0	45	45	EDN	N/A
	Union Valley Reservoir	277.0	341.5	3.0	1400.0	1484.4	25	25	UNV	11441001
Cosumnes	Jenkinson Lake	41.0	50.6	0	0.0	50.0	65	65	JNK	N/A
Feather	Antelope Lake	24.3	30.0	17	1497.2	1526.2	39	39	ANT	N/A
	Belden Reservoir	2.4	3.0	3.0	0.0	3.9	1	1	N/A	N/A
	Bucks Lake	105.6	130.2	80	1506.9	1571.2	16	16	BCL	11403500
	Butt Valley Reservoir	49.9	61.5	36	1241.8	1259.5	15	15	BTV	11401050
	Frenchman Lake	58.8	72.5	10.6	1669.7	1703.9	98	98	FRD	N/A
	Lake Almanor	1175.0	1448.8	750	1336.5	1370.2	15	15	ALM	11399000
	Lake Davis	85.5	105.5	34.6	1728.2	1760.3	98	98	DAV	N/A
	Little Grass Valley Reservoir	89.8	110.7	55	1475.8	1538.3	15	15	LGV	11395020

	Mountain Meadows Reservoir	24.8	30.6	0	1525.2	1533.1	15	15	MMW	N/A
	Sly Creek Reservoir	64.3	79.3	1.8	1004.3	1076.2	15	15	SLC	11395400
Kern	Lake Isabella	562.4	693.4	0	746.5	794.0	15	15	ISB	11190500
Kings	Courtright Reservoir	123.3	152.0	39	2400.9	2494.5	15	15	CTG	11214550
	Wishon Reservoir	128.6	158.6	20	1917.1	1996.4	16	16	WSN	11214800
Mokelumne	Lower Bear River Reservoir	52.0	64.1	4.1	1706.9	1773.9	16	16	LWB	11315600
	Salt Springs Reservoir	141.9	174.9	6.2	1107.9	1206.4	29	29	SLS	11313500
San Joaquin	Bass Lake	45.1	55.6	27	986.3	1029.1	17	17	CNV	11243400
	Florence Lake	64.4	79.4	1.25	2188.5	2233.4	15	99	FLR	11229600
	Huntington Lake	89.2	109.9	37	2068.4	2118.4	15	15	HNT	11236000
	Kerckhoff Lake	4.2	5.2	4.3	270.8	299.5	65	65	KRH	11246650
	Lake Thomas A Edison	125.0	154.2	8	2281.0	2329.4	15	16	TAE	11231000
	Mammoth Pool Reservoir	119.9	147.9	5	944.9	1015.0	26	26	MPL	11234700
	Redinger Lake	26.1	32.2	5.28	359.8	427.6	55	55	RDN	11241950
	Shaver Lake	135.6	167.2	0.47	1582.2	1636.8	25	25	SHV	11239500
Stanislaus	Beardsley Reservoir	98.5	121.5	25	953.1	1035.7	25	25	BRD	11292800
	Donnells Reservoir	64.7	79.8	6.2	1411.5	1498.7	15	15	DON	11292600
	Lyons Reservoir	4.9	6.0	1.25	1248.1	1286.3	26	26	LYS	11297700
	New Spicer Meadow Reservoir	184.3	227.2	50	1940.1	2015.9	15	15	SPM	11293770
	Pinecrest Reservoir	18.3	22.6	4	1671.2	1712.2	15	99	SWB	11297700
	Relief Reservoir	12.3	15.2	1.2	2156.6	2232.1	15	15	RLF	11291000
Tuolumne	Cherry Lake	274.3	338.2	0	1353.3	1433.5	17	17	CHY	11277200
	Hetch Hetchy Reservoir	360.4	444.4	123.3	1070.5	1160.1	18	18	HTH	11275500

	Lake Eleanor	26.1	32.2	0	1404.5	1421.3	15	17	ENR	11277500
Yuba-Bear	Bowman Lake	68.5	84.5	0	1648.9	1696.3	15	15	BWN	11415500
	Buck Island Reservoir	1.1	1.3	0	1949.5	1964.7	15	15	N/A	N/A
	Camp Far West Lake	104.5	128.8	0	48.8	96.0	65	65	CFW	N/A
	Englebright Lake	70.0	86.3	74.0	0.0	85.3	35	35	ENG	11417950
	Fordyce Lake	49.9	61.5	0.15	1914.1	1953.8	15	15	N/A	11414090
	Jackson Meadows Reservoir	69.2	85.3	0	1794.2	1841.0	15	15	JCK	11407800
	Lake Combie	5.6	6.8	0	0.0	26.0	55	55	CMB	N/A
	Lake Spaulding	75.1	92.6	0	1472.9	1540.8	15	15	SPG	11414140
	New Bullards Bar Reservoir	966.1	1191.2	288.6	411.5	615.7	25	25	BUL	11413515
	Rock Creek Reservoir	0.4	0.5	0	433.2	440.3	25	25	N/A	N/A
	Rollins Reservoir	66.0	81.4	0	596.0	662.3	45	45	RLL	11421800
	Scotts Flat Reservoir	48.5	59.8	0	0.0	53.3	15	15	SFL	11418250

Table A-2. Fixed Head Hydropower Plant Parameters

Watershed	Name	Demand method	Max. flow (ft^3/s)	Fixed head (ft)	Plant efficiency (%)	Hydropower priority	Spill demand priority	Flow gauge	EIA ID
American	Camino	WYI	2000	997	90	39	39	USGS_11441895	430
	El Dorado ID	WYI	150	984	90	15	19	USGS_11439300	238
	French Meadows	WYI	400	656	90	15	19	USGS_11427200	424
	Jaybird	WYI	1378	1476	90	25	29	USGS_11441780	431
	Jones Fork	WYI	281	577	90	15	19	USGS_11440900	534
	Loon Lake	WYI	997	1100	90	15	19	USGS_11429340	432
	Middle Fork	WYI	920	1936	90	25	29	USGS_11428600	425
	Ralston	WYI	924	1312	90	39	39	USGS_11427765	427
	Robbs Peak	WYI	1046	330	90	25	25	USGS_11429300	433
	White Rock	WYI	3500	780	90	45	49	USGS_11443460	435
Feather	Belden	Max Capacity	2410	770	90	N/A	25	USGS_11403050	219
	Bucks Creek	WYI	384	2558	90	15	19	USGS_11403700	220
	Butt Valley	Max Capacity	2118	362	90	N/A	29	USGS_11400600	221
	Caribou 1	WYI	1114	1150	90	14	19	USGS_11401110	222
	Caribou 2	WYI	1464	1151	90	14	19	USGS_11401110	223
	Cresta	Max Capacity	3510	290	90	N/A	49	USGS_11404360	231
	Forbestown	Max Capacity	620	795	90	N/A	25	USGS_11396290	417
	Grizzly	Max Capacity	375	705	90	N/A	29	USGS_11404240	7338
	Hamilton Branch	Max Capacity	200	410	90	N/A	21	N/A	242
	Kanaka	Max Capacity	32	542	90	N/A	15	USGS_11396396	54653
	Kelly Ridge	Max Capacity	255	628	90	N/A	35	USGS_11396329	418

	Lime Saddle	Max Capacity	87	462	90	N/A	29	N/A	255
	Poe	Max Capacity	3700	488	90	N/A	59	USGS_11404900	272
	Rock Creek	Max Capacity	2880	535	90	N/A	39	USGS_11403800	275
	Toadtown	Max Capacity	125	131	90	N/A	19	USGS_11389800	714
	Woodleaf	WYI	580	1456	90	14	25	USGS_11396090	419
Kaweah	Kaweah 1	Max Capacity	23	1260	90	N/A	19	USGS_11208720	337
	Kaweah 2	Max Capacity	87	344	90	N/A	29	USGS_11208570	336
	Kaweah 3	Max Capacity	97	750	90	N/A	19	USGS_11207500	338
Kern	Borel	Max Capacity	590	255	90	N/A	14	USGS_11187500	328
	Kern Canyon	Max Capacity	705	264	90	N/A	49	USGS_11192940	7911
	Kern River 1	Max Capacity	412	865	90	N/A	39	USGS_11192000	340
	Kern River 3	Max Capacity	620	850	90	N/A	18	USGS_11185500	339
	Rio Bravo	Max Capacity	1500	121	90	N/A	59	USGS_11193010	50037
Kings	Balch 1 and 2	Max Capacity	843	2379	90	N/A	39	USGS_11216300	217 & 218
	Haas	WYI	825	2444	90	15	29	USGS_11216050	240
	Helms	Max Capacity	9000	1744	90	N/A	19	USGS_11214540	6100
	Kings River	Max Capacity	990	798	90	N/A	49	USGS_11218700	254
Mokelumne	Electra	Max Capacity	1130	1272	90	N/A	49	PG&E_M65	239
	Salt Springs 2	WYI	225	2117	90	15	19	USGS_11313510	N/A
	Tiger Creek	WYI	750	1219	90	25	29	USGS_11316610	287
	West Point	Max Capacity	675	312	90	N/A	39	PG&E_M64	291
San Joaquin	Big Creek 1	WYI	692	1923	90	14	18	USGS_11238100	317
	Big Creek 2	Max Capacity	607	1638	90	N/A	29	USGS_11238380	318
	Big Creek 2A	WYI	625	2200	90	25	19	USGS_11238400	322

	Big Creek 3	Max Capacity	3200	764	90	N/A	49	USGS_11241800	319
	Big Creek 4	WYI	3700	388	90	55	59	USGS_11246530	320
	Big Creek 8	Max Capacity	1332	685	90	N/A	39	USGS_11238550	321
	Eastwood	WYI	2296	1312	90	15	19	USGS_11238250	104
	Kerckhoff 1	WYI	1735	351	90	64	69	USGS_11246950	250
	Kerckhoff 2	WYI	5100	420	90	65	69	USGS_11247050	682
	Mammoth Pool	WYI	2500	1004	90	25	29	USGS_11235100	344
	Portal	Max Capacity	724	190	90	N/A	29	USGS_11235500	354
	San Joaquin 1	Max Capacity	235	1305	90	N/A	49	USGS_11246610	293
	San Joaquin 1A	Max Capacity	167	40	90	N/A	39	USGS_11246590	278
	San Joaquin 2	Max Capacity	150	292	90	N/A	29	USGS_11246570	276
	San Joaquin 3	WYI	150	378	90	15	19	USGS_11244100	277
Stanislaus	Angels	Max Capacity	40	444	90	N/A	39	N/A	215
	Collierville	WYI	1400	2192	90	15	19	USGS_11295250	54555
	Donnells	WYI	700	1151	90	19	19	USGS_11292610	415
	Murphys	Max Capacity	68	684	90	N/A	29	N/A	261
	Phoenix	WYI	25	25	90	25	29	PG&E_S108	264
	Sand Bar	WYI	600	427	90	25	29	USGS_11292860	777
	Spring Gap	WYI	59	1865	90	15	39	USGS_11297000	284
	Stanislaus	WYI	830	1520	90	25	39	USGS_11295505	285
Tule	Lower Tule R	Max Capacity	35	1140	90	N/A	29	USGS_11202700	365
	Tule River	Max Capacity	70	1544	90	N/A	19	USGS_11201700	289
Tuolumne	Dion R Holm	WYI	1000	2100	90	15	19	SFPUC_HPH	380
	Kirkwood	WYI	1400	1100	90	15	19	SFPUC_KPH	382

	Moccasin	WYI	1200	1240	90	16	29	SFPUC_MPH	381
Yuba-Bear	Alta	Max Capacity	56	650	90	N/A	20	USGS_11421725	214
	Chicago Park	WYI	1100	480	90	39	39	USGS_11421780	412
	Colgate	WYI	3400	1306	90	25	29	USGS_11413510	454
	Deer Creek	WYI	66	838	90	14		USGS_11414205	233
	Drum 1	WYI	360	1379	90	15	19	USGS_11414194	235
	Drum 2	WYI	500	1376	90	15	19	USGS_11414195	236
	Dutch Flat 1	WYI	490	581	90	15	29	USGS_11421750	237
	Dutch Flat 2	WYI	600	581	90	15	29	USGS_11421760	413
	Halsey	WYI	294	326	90	48	48	USGS_11425310	241
	Narrows 1	WYI	730	236	90	35	39	USGS_11417970	262
	Narrows 2	WYI	3400	200	90	35	39	USGS_11417980	455
	Newcastle	WYI	392	410	90	59	59	USGS_11425416	632
	Spaulding 1	WYI	550	198	90	19	19	USGS_11414154	281
	Spaulding 2	WYI	200	346	90	18	18	USGS_11414155	282
	Spaulding 3	WYI	330	328	90	17	17	USGS_11416200	283
	Wise 1 and 2	WYI	473	522	90	59	59	USGS_11425415	292

Table A-3. Variable Head Hydropower Plant Parameters

Watershed	Name	Owner	Reservoir	Max. flow (ft^3/s)	Efficiency (%)	Tailwater elevation (m)	Flow gauge	EIA ID
American	Chili Bar	Pacific Gas & Electric Co	Chili Bar Reservoir	1659	90	0.0	N/A	225
	Hell Hole	Placer County Water Agency	Hell Hole Reservoir	20	90	1306.0	N/A	763
	Oxbow	Placer County Water Agency	Oxbow Reservoir	1100	90	0.0	USGS_11433212	426
	Slab Creek	Sacramento Municipal Utility Dist.	Slab Creek Reservoir	36	90	515.1	N/A	522
	Union Valley	Sacramento Municipal Utility Dist.	Union Valley Reservoir	1577	90	1400.0	USGS_11441002	6612
Feather	Oak Flat	Pacific Gas & Electric Co	Belden Reservoir	140	90	0.0	N/A	626
	Sly Creek	Northern California Power Agency	Sly Creek Reservoir	700	90	1104.3	USGS_11395400	776
Mokelumne	Salt Springs 1	Pacific Gas & Electric Co	Salt Springs Reservoir	225	90	1107.9	CDEC_SLS	279
San Joaquin	Crane Valley	Pacific Gas & Electric Co	Bass Lake	160	90	986.3	USGS_11243400	230
Stanislaus	Beardsley	Oakdale & South San Joaquin Irr. Dist.	Beardsley Reservoir	620	90	953.1	USGS_11292800	414
	New Spicer Meadow	Northern California Power Agency	New Spicer Meadow Reservoir	200	90	1940.1	USGS_11293760	54554
Yuba-Bear	Bowman	Pacific Gas & Electric Co	Bowman Lake	313	90	1647.7	N/A	848
	Camp Far West	Sacramento Municipal Utility Dist.	Camp Far West Lake	25	90	48.8	N/A	531
	Combie	Nevada Irrigation District	Lake Combie	5	90	0.0	N/A	846 & 847
	Fish Power	Yuba County Water Agency	New Bullards Bar	5	90	411.5	N/A	4229
	Rollins	Nevada Irrigation District	Rollins Reservoir	840	90	597.0	USGS_11421900	34

Table A-4. Water Supply Demand Parameters

Watershed	Supply demand name	Weekly demand	Annual demand (million m^3)	Weekly variation	Demand Priority
American	Folsom	N/A	10.7	Variable	65
Feather	California Water Service Company (CalWater) - Oroville	N/A	38.5	Variable	23
	South Feather Water & Power Agency (SFWPA) - Bangor	N/A	11.4	Variable	25
	South Feather Water & Power Agency (SFWPA) - Forbestown	N/A	7.5	Variable	13
Mokelumne	Amador Water Agency (AWA)	N/A	1.7	Constant	33
	Calaveras Public Utilities District (CPUD)	N/A	1.9	Constant	13
Tule	Crabtree-Aiken Ditch Co.	N/A	5.8	Constant	23
	Graham Osborn Ditch Co.	N/A	10.7	Constant	23
	Mt Whitney Ditch Co.	N/A	3.6	Constant	22
	Pleasant Valley Canal Co.	N/A	10.7	Constant	23
	South Tule Ditch Co.	N/A	14.3	Constant	13
Tuolumne	San Francisco Public Utilities Commission (SFPUC)	N/A	(-0.0116*WYI_SJValley + 0.26)*1233	Variable	13
Yuba-Bear	Nevada Irrigation District (NID) 1	Variable	N/A	N/A	23
	Nevada Irrigation District (NID) 2	Variable	N/A	N/A	23
	Nevada Irrigation District (NID) 3	Variable	N/A	N/A	53
	Nevada Irrigation District (NID) 4 Cascade	Variable	N/A	N/A	13
	Nevada Irrigation District (NID) 5 Deer Creek	Variable	N/A	N/A	13
	Placer County Water Agency (PCWA) 1	Variable	N/A	N/A	13
	Placer County Water Agency (PCWA) 2	Variable	N/A	N/A	43
	Placer County Water Agency (PCWA) 3	Variable	N/A	N/A	24
	Placer County Water Agency (PCWA) 4	Variable	N/A	N/A	24
	Placer County Water Agency (PCWA) 5	Variable	N/A	N/A	24
	Sly Folsom	N/A	9.3	Variable	65
	South Fork Feather River (SFFR)	N/A	(0.003*WYI_SacValley + 0.0522)*1233	Variable	13
	Yuba County Water Agency (YCWA) Wheatland	Variable	N/A	N/A	47

Table A-5. Instream Flow Requirement (IFR) Parameters

Watershed	Name	River	Regulator	Definition source	Priority
American	IFR bl Buck Island	Little Rubicon	Buck Island Reservoir	P-2101 FERC license	12
	IFR bl Buck Loon Tunnel	Rubicon River	Buck Look Diversion	P-2101 FERC license	13
	IFR blCaples	CaplesCr.	Caples Lake	P-0184 FERC license	11
	IFR bl Chili Bar	S Fk American	Chili Bar Reservoir	P-2155 FERC license	51
	IFR bl Duncan Tunnel	Duncan Cr.	Duncan Tunnel Div. Reservoir	P-2079 FERC license	11
	IFR bl El Dorado ID Canal	S Fk American	El Dorado ID Div. Reservior	P-0184 FERC license	12
	IFR bl French Meadows	M Fork American	French Meadows Reservoir	P-2079 FERC license	12
	IFR bl Hell Hole	Rubicon River	Hell Hole Reservoir	P-2079 FERC license	21
	IFR bl Ice House	S Fk Silver Creek	Ice House Reservoir	P-2101 FERC license	11
	IFR bl Jaybird Tunnel	Silver Cr.	Junction Reservoir	P-2101 FERC license	22
	IFR bl Long Canyon Creek Tunnel	Long Canyon Cr.	Long Canyon Creek Tunnel	P-2079 FERC license	21
	IFR bl Loon	GerleCr.	Loon Lake	P-2101 FERC license	14
	IFR bl Ralston Tunnel	M Fork American	Ralston Tunnel	P-2079 FERC license	31
	IFR bl Rubicon	Rubicon River	Rubicon Reservoir	P-2101 FERC license	11
	IFR bl Silver	Silver Fk American	Silver Lake	P-0184 FERC license	11
	IFR bl Slab Creek	S Fk American	Slab Cr. Reservoir	P-2101 FERC license	41
Cosumnes	IFR bl Camp Creek Tunnel	Camp Cr.	Camp Creek Tunnel	Central Valley Project, Sly Park Unit	11

Table A-5 (cont'd). Instream Flow Requirement (IFR) Parameters

Watershed	Name	River	Regulator	Definition source	Priority
Feather	IFR at Pulga Gage	N Fk Feather	Poe Div. Dam	P-2107 FERC license	51
	IFR bl Almanor	N Fk Feather	Canyon Dam	P-2105 FERC license	11
	IFR bl Antelope Lake	Indian Cr.	Antelope Lake Dam	Historical flows	11
	IFR bl Belden Forebay	N Fk Feather	Belden Forebay	Historical flows	21
	IFR blCrestaForebay	N Fk Feather	CrestaForebay	P-2105 FERC license	41
	IFR blForbestownDiv	S Fk Feather	ForbestownDiv. Dam	P-2088 FERC license	11
	IFR bl Frenchman Lake	Last Chance Cr.	Frenchman Lake Dam	Historical flows	11
	IFR bl Grizzly Forebay	Grizzly Cr. of NF Feather	Grizzly Forebay Dam	P-0619 FERC license	11
	IFR bl Hamilton Branch Div	Hamilton Branch	Hamilton Branch Div	PG&E 2000 Hydrodivestiture Draft EIR	11
	IFR bl Kanaka Div	Sucker Run	Kanaka Div. Dam	P-7242 FERC license	11
	IFR bl Lake Davis	Grizzly Cr. of MF Feather	Lake Davis Dam	Historical flows	11
	IFR bl Little Grass Valley Reservoir	S Fk Feather	Little Grass Valley Dam	P-2088 FERC license	11
	IFR bl Lost Creek Div	Lost Cr.	Lost Cr.Div. Dam	P-2088 FERC license	11
	IFR bl Lower Bucks Lake	Bucks Cr.	Lower Bucks Lake	P-0619 FERC license	11
	IFR bl Mountain Meadows	Hamilton Branch	Indian Ole Dam	PG&E 2000 Hydrodivestiture Draft EIR	11
	IFR bl Poe Div	N Fk Feather	Poe Div. Dam	P-2107 FERC license	51
	IFR bl Rock Creek Reservoir	N Fk Feather	Rock Creek Dam	P-2105 FERC license	31
	IFR bl South Fork Div	S Fk Feather	SFkDiv. Dam	P-2088 FERC license	11
Kaweah	IFR bl Conduit 1 Div	E Fk Kaweah River	Conduit 1 Div	P-0298 FERC license	11
	IFR bl Conduit 2 Div	M Fk Kaweah	Conduit 2 Div	P-0298 FERC license	21
	IFR bl Conduit 3 Marble FkDiv	Marble Fk Kaweah	Conduit 3 Marble FkDiv	P-0298 FERC license	11
	IFR bl Conduit 3 Middle FkDiv	M Fk Kaweah	Conduit 3 Middle FkDiv	P-0298 FERC license	11

Table A-5 (cont'd). Instream Flow Requirement (IFR) Parameters

Watershed	Name	River	Regulator	Definition source	Priority
Kern	IFR bl Democrat Dam	Kern River	Democrat Dam	P-1930 FERC license	31
	IFR bl Fairview Dam	Kern River	Fairview Dam	P-2290 FERC license	11
	IFR bl FERC 178 Div. Dam	Kern River	FERC 178 Div. Dam	P-0178 FERC license	41
	IFR bl Isabella AUX Dam	Kern River	Isabella AUX Dam	P-0382 FERC license	21
	IFR bl Rio Bravo Div. Dam	Kern River	Rio Bravo Div. Dam	P-4129 FERC license	51
Kings	IFR bl Balch AB Dam	N Fk Kings	Balch AB Dam	P-1988 FERC license	41
	IFR bl Black Rock Dam	N Fk Kings	Black Rock Dam	P-0175 FERC license	31
	IFR blCourtright Dam	Helms Cr.	Courtright Dam	P-1988 FERC license	11
	IFR bl Kings Penstock	DinkeyCr.	Kings Penstock	P-1988 FERC license	41
	IFR blWishon Dam	N Fk Kings	Wishon Dam	P-1988 FERC license	12
Mokelumne	IFR bl Bear River Div	Cole Cr.	Bear River Div	P-0137 FERC license, 2002 Streamflow Capability Report	11
	IFR bl Cole Creek Div	Cole Cr.	Cole Creek Div	P-0137 FERC license, 2002 Streamflow Capability Report	11
	IFR bl Electra Div	N Fk Mokelumne	Electra Div	P-0137 FERC license, 2002 Streamflow Capability Report	41
	IFR bl Lower Bear River Res	Bear River	Lower Bear River Res	P-0137 FERC license, 2002 Streamflow Capability Report	11
	IFR bl Salt Springs Dam	N Fk Mokelumne	Salt Springs Dam	P-0137 FERC license, 2002 Streamflow Capability Report	29
	IFR bl Tiger Cr. Regulator	Tiger Cr.	Tiger Cr. Regulator	P-0137 FERC license, 2002 Streamflow Capability Report	21
	IFR bl Tiger Res	N Fk Mokelumne	Tiger Res	P-0137 FERC license, 2002 Streamflow Capability Report	31

Table A-5 (cont'd). Instream Flow Requirement (IFR) Parameters

Watershed	Name	River	Regulator	Definition source	Priority
San Joaquin	IFR bl Bear Cr.Div. Dam	Bear Cr.	Bear Cr.Div. Dam	P-2085& P-2175 FERC licenses	11
	IFR bl Big Cr. 5 Dam	Big Cr.	Big Cr. 5 Dam	P-2085& P-2175 FERC licenses	31
	IFR bl Big Cr. No. 6 Dam	San Joaquin River	Big Cr. No. 6 Dam	P-2085& P-2175 FERC licenses	41
	IFR blBolsilloCr. Div. Dam	BolsilloCr.	BolsilloCr. Div. Dam	P-2085& P-2175 FERC licenses	11
	IFR bl Camp 62 Cr. Div. dam	Camp 62 Cr.	Camp 62 Cr. Div. dam	P-2085& P-2175 FERC licenses	11
	IFR bl Chinquapin Cr. Div. Dam	Chinquapin Cr.	Chinquapin Cr. Div. Dam	P-2085& P-2175 FERC licenses	11
	IFR bl Crane Valley Dam	N Fk Willow Cr.	Crane Valley Dam	P-1354 FERC license	11
	IFR bl Florence Dam	S Fk San Joaquin	Florence Dam	P-2085& P-2175 FERC licenses	10
	IFR bl Huntington Dam	Big Cr.	Huntington Dam	P-2085& P-2175 FERC licenses	11
	IFR blKirckhoff Dam	San Joaquin River	Kirckhoff Dam	P-0096 FERC license	61
	IFR bl Mammoth Pools Dam	San Joaquin River	Mammoth Pools Dam	P-2085& P-2175 FERC licenses	11
	IFR bl Manzanita Dam	N Fk Willow Cr.	Manzanita Dam	P-1354 FERC license	21
	IFR bl Mono Cr. Div. Dam	Mono Cr.	Mono Cr. Div. Dam	P-2085& P-2175 FERC licenses	11
	IFR bl Pitman Cr. Div. Dam	Pitman Cr.	Pitman Cr. Div. Dam	P-2085& P-2175 FERC licenses	11
	IFR blRedinger Dam	San Joaquin River	Redinger Dam	P-2017 FERC license	51
	IFR bl SF Willows Cr.Div. Dam	Willow Cr.	SF Willows Cr.Div. Dam	P-1354 FERC license	11
	IFR bl Shaver Dam	Stevenson Cr.	Shaver Dam	P-2085& P-2175 FERC licenses	21
	IFR bl Tunnel No. 7 to Shaver L.	N Fk Stevenson Cr.	Tunnel No. 7 to Shaver	P-2085& P-2175 FERC licenses	11
	IFR bl Willow Creek near Rex Ranch	Willow Cr.	Willow Creek near Rex Ranch	P-1354 FERC license	21

Table A-5 (cont'd). Instream Flow Requirement (IFR) Parameters

Watershed	Name	River	Regulator	Definition source	Priority
Stanislaus	IFR bl Angles Div.	Angels Cr.	Angles Div.	P-2699 FERC license	21
	IFR bl Beaver Cr.Div. Dam	Beaver Cr.	Beaver Cr.Div. Dam	P-2409 FERC license	11
	IFR blDonnells Dam	M Fk Stanislaus	Donnells Dam	P-2005 FERC license	11
	IFR bl Hunters Dam	Mill Cr.	Hunters Dam	P-2019 FERC license	21
	IFR bl Lyons Res Dam	S Fk Stanislaus	Lyons Res Dam	P-1061 FERC license	21
	IFR blMcKays Point Div. Dam	N Fk Stanislaus	McKays Point Div. Dam	P-2409 FERC license	11
	IFR bl New Spicer Dam	Highland Cr.	New Spicer Dam	P-2409 FERC license	11
	IFR bl Philadelphia Div. Dam	S Fk Stanislaus	Philadelphia Div. Dam	P-2130 FERC license	11
	IFR bl Relief Dam	Summit Cr.	Relief Dam	P-2130 FERC license	11
	IFR bl Sand Bar Div. Dam	M Fk Stanislaus	Sand Bar Div. Dam	P-2130 FERC license	31
	IFR bl Utica Dam	N Fk Stanislaus	Utica Dam	P-11563 FERC license	11
Tule	IFR bl Tule R. Div. Dam	M Fk North Fk Tule	Tule R. Div. Dam	P-1333 FERC license	11
Tuolumne	IFR bl Cherry Lake Res	Cherry Cr.	Cherry Lake Reservoir		11
	IFR bl Hetch Hetchy Res	Tuolumne River	Hetch Hetchy Reservoir		18
	IFR bl Lake Eleanor	Eleanor Cr.	Lake Eleanor		11

Table A-5 (cont'd). Instream Flow Requirement (IFR) Parameters

Watershed	Name	River	Regulator	Definition source	Priority
Yuba-Bear	IFR bl Bear Meadow	Bear R	Bear Meadow	P-2310 FERC license	11
	IFR bl Bowman	Canyon Cr.	Bowman Lake	P-2266 FERC license	12
	IFR bl Camp Far West	Bear R	Camp Far West Reservoir		61
	IFR blCombie	Bear R	Lake Combie	P-2266 FERC license	51
	IFR bl Daguerre Point	Yuba River	Daguerre Point Div. Reservoir	State Water Resources Control Board RD-1644	46
	IFR bl Drum Afterbay	Bear River	Drum Afterbay	P-2310 FERC license	14
	IFR bl Dutch Flat Afterbay	Bear River	Dutch Flat Afterbay	P-2266 FERC license	31
	IFR bl Fordyce	Fordyce Cr.	Lake Fordyce	P-2310 FERC license	11
	IFR bl Jackson Meadows	M Fk Yuba	Jackson Meadows Reservoir	P-2266 FERC license	10
	IFR bl Milton	M Fk Yuba	Milton Div. Reservoir	P-2266 FERC license	11
	IFR bl Narrows at Smartville	Yuba River	Englebright Reservoir	State Water Resources Control Board RD-1644	31
	IFR bl New Bullards Bar	N Fk Yuba	New Bullards Bar Reservoir	P-2246 FERC license	23
	IFR bl Oregon Creek Div	Oregon Cr.	Oregon Creek Div.	P-2246 FERC license	22
	IFR bl Our House	M Fk Yuba	Our House Div. Reservoir	P-2246 FERC license	21
	IFR bl Rollins	Bear R	Rollins Reservoir	P-2266 FERC license	41
	IFR bl Scotts Flat	Deer Cr.	Scotts Flat Reservoir		11
	IFR bl South Canal Inflow	Mormon Ravine	South Canal Inflow	P-2310 FERC license	51
	IFR bl Spaulding at Langs Crossing	S Fk Yuba	Lake Spaulding	P-2310 FERC license	12
	IFR bl Spaulding at Spaulding 2 PH	S Fk Yuba R bl Spaulding	Lake Spaulding	P-2310 FERC license	11

Table A-6. Conveyance Parameters

Watershed	Conveyance	Max. capacity (ft^3/s)
American	Buck Loon Tunnel	1260
	Camino Tunnel	2000
	Camp CreekTunnel	500
	Duncan Tunnel	400
	El Dorado ID Canal	165
	French Meadows Hell Hole Tunnel	400
	Hell Hole Middle Fork Tunnel	920
	Jaybird Tunnel	1345
	Jones Fork Tunnel	287
	Long Canyon Creek Tunnel	300
	Loon Lake Tunnel	997
	Ophir Tunnel	N/A
	Ralston Tunnel	836
	Robbs Peak Tunnel	1250
	Rockbound Tunnel	1300
	Sly Park Canal	N/A
	White Rock Tunnel	3500
Feather	Belden Tunnel	2410
	Bucks Diversion	330
	Butt Valley Tunnel	2118
	Caribou 1 Penstock	1114
	Caribou 2 Penstock	1464
	Cresta Tunnel	3850
	Forbestown Diversion	660

Watershed	Conveyance	Max. capacity (ft^3/s)
Kings	Balch Tunnel	843
	Haas Tunnel	825
	Helms Aqueduct	9000
	Kings Aqueduct Dinkey Cr. Div.	10
	Kings River Aqueduct	950
Mokelumne	Bear River Div.	85
	Bear River Div. Tunnel, Fwd	800
	Bear River Div. Tunnel, Rev	800
	Cole Creek Div.	N/A
	Electra Tunnel	875
	Lower Tiger Cr. Div. Tunnel	625
	Salt Springs 2 Penstock	225
	Tiger Creek Canal	550
	West Point Diversion	675
San Joaquin	Balsam Diversion Tunnel	2500
	Bear Diversion Tunnel	450
	Big Creek 3 Aqueduct	3250
	Big Creek 4 Aqueduct	3700
	Big Creek 8 Penstock	1173
	Browns Creek Ditch	80
	Eastwood Tunnel	2500
	Kerckhoff 1 Tunnel	6500
	Kerckhoff 2 Tunnel	5100
	Mammoth Pool Tunnel	2500

	Grizzly Forebay Tunnel	360		Mono Tunnel	650
	Grizzly Tunnel	400		No. 1 Conduit	210
	Hamilton Branch	210		No. 2 Conduit	160
	Hendricks Canal	125		No. 3 Conduit	160
	Kanaka Div	37		PH 2A Aqueduct	650
	Kelly Ridge Div	350		Portal Aqueduct	650
	Miners Ranch Canal	300		Portal Penstock	1500
	Poe Aqueduct	3700		Tunnel No. 1	700
	Rock Creek Tunnel	2880		Tunnel No. 2	620
	Slate Cr Tunnel	848		Tunnel No. 7	2439
	South Fork Diversion Tunnel	600		Ward Tunnel	1760
	Upper Miocene Canal	65	Stanislaus	Angels Canal	45
	Woodleaf Diversion	620		DonnellsDiv	750
Kaweah	Conduit No. 3	97		Lower Collierville Tunnel 1	1475
	Conduit No. 3 Marble Fk	50		Lower Collierville Tunnel 2	1475
	Conduit No. 3 Middle Fk	65		Lower Utica Canal	45
	Kaweah 1 Aqueduct	25		Phoenix Canal	33
	Kaweah 2 Aqueduct	85		Philadelphia Aqueduct	60
Kern	Borel Canal	605		Sand Bar Power Tunnel	600
	Kern Canyon Aqueduct	750		Stanislaus Tunnel	530
	Kern River 3 Aqueduct	590		UPA Tunnel Tap	88
	Kern River Flume	412		Upper Collierville Tunnel	200
	Rio Bravo Canal	1800		Upper Utica Canal	88

A-6 (cont'd). Conveyance Parameters

Watershed	Conveyance	Max. capacity (ft^3/s)
Tule	Lower Tule R Aqueduct	35
	Upper Tule R Conduit	66
Tuolumne	Canyon Power Tunnel	1500
	Dion R. Holm Tunnel	1000
	Hetch Hetchy Aqueduct	900
	Hetch Hetchy Aqueduct to SF	465
	Lake Eleanor Tunnel	720
	Moccasin Aqueduct	900
Yuba-Bear	Bear River Canal	470
	Bowman Spaulding Conduit	325
	Texas Creek Div.	250
	Camptonville Tunnel	1071
	Chicago Park Flume	1100
	Drum 1 Penstock	360
	Drum 2 Penstock	500
	Drum Bear Div.	N/A
	Drum Canal	840
	Dutch Flat 1	490
	Dutch Flat 2	610
	Lohman Ridge Tunnel	1071
	Lower Boardman Canal	N/A
	Lower Wise Canal	473

	Milton Bowman Tunnel	429
	Narrows 1 Penstock	70
	Narrows 2 Penstock	3490
	New Colgate Tunnel	3800
	South Canal	375
	S. Canal to Mormon Ravine	N/A
	South Yuba Canal	125
	Towle Canal	42
	Upper Wise Canal	488