CLIMATE CHANGE IMPACTS ON THE OPERATION OF TWO HIGH-ELEVATION HYDROPOWER SYSTEMS IN CALIFORNIA

A Paper From:
California Climate Change Center

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DRAFT PAPER

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Arnold Schwarzenegger, *Governor*

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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California's electricity and natural gas ratepayers. The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts focus on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

In 2003, the California Energy Commission's PIER Program established the **California Climate Change Center** to document climate change research relevant to the states. This center is a virtual organization with core research activities at Scripps Institution of Oceanography and the University of California, Berkeley, complemented by efforts at other research institutions. Priority research areas defined in PIER's five-year Climate Change Research Plan are: monitoring, analysis, and modeling of climate; analysis of options to reduce greenhouse gas emissions; assessment of physical impacts and of adaptation strategies; and analysis of the economic consequences of both climate change impacts and the efforts designed to reduce emissions.

The California Climate Change Center Report Series details ongoing center-sponsored research. As interim project results, the information contained in these reports may change; authors should be contacted for the most recent project results. By providing ready access to this timely research, the center seeks to inform the public and expand dissemination of climate change information, thereby leveraging collaborative efforts and increasing the benefits of this research to California's citizens, environment, and economy.

For more information on the PIER Program, please visit the Energy Commission's website www.energy.ca.gov/pier/ or contract the Energy Commission at (916) 654-5164.

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Abstract

The work presented in this paper shows an estimate of the impacts of climate change on two high-elevation hydropower systems in California: the Upper America River Project, operated by Sacramento Municipal Utility District in Northern California, and the Big Creek system, operated by Southern California Edison in Southern California. The study builds on previous work modeling the Upper American River Project System. The model presented here includes methodological improvements to better simulate historical operations and more accurately project future operations of both hydropower systems. The operations of these two high-elevation systems were simulated using historical and climate change scenarios. Hydrologic scenarios under climate change imply an average reduction in runoff for both systems (with a greater reduction for the Big Creek systems) and a change in the hydrograph towards earlier timing of runoff. The change in the hydrograph is greater for the Upper America River Project system because of the lower elevation of the basins where the system is located. The simulation results show that associated with the reduction in runoff there is a reduction in energy generation in both systems. However, due to the greater change in the hydrologic conditions for the Upper America River Project system, spills are greater in that system, and hence the reduction in energy generation (and associated revenues) is greater as well. In both systems the ability to meet peak historical power demands in the summer months would remain basically unaltered. However, an increase in the occurrence of heat waves especially later in the summer period (September) would increase peak power demand at times when these systems might not be at peak power capacity unless operating strategies are modified.

Keywords: Hydropower, California, high elevation, climate change, simulation

Executive Summary

This research estimated the impacts of climate change on two high-elevation hydropower systems in California: the Upper America River Project, operated by Sacramento Municipal Utility District in Northern California, and the Big Creek system, operated by Southern California Edison in Southern California. The study builds on previous work modeling the Upper America River Project system. The model presented here shows improvements on that model that represent a better simulation of historical operations and improve the methodology to project future operations of both hydropower systems. The future operations of these two high-elevation systems were simulated using new climate change scenarios provided for the Second Biennial Science Report to the California Climate Action Team. These new hydrologic conditions mean reduced runoff for both systems (with a greater reduction for the Big Creek systems) and a change in the hydrograph towards earlier timing of runoff. The change in the hydrograph is greater for the Upper America River Project system because of the lower elevation of the basins where the system is located. Associated with the reduction in runoff there is a reduction in energy generation in both systems. However, due to the greater change in the hydrologic conditions for the Upper America River Project system, spills are greater in that system, and hence the reduction in energy generation (and associated revenues) is greater as well. In both systems the ability to meet peak historical power demands in the summer months would remain basically unaltered. However, an increase in the occurrence of heat waves especially later in the summer period (September) would increase peak power demand at times when these systems might not be at peak power capacity unless operating strategies are modified.

1.0 Introduction

As climate change becomes more evident there is an increasing interest in determining the possible impacts on different sectors of the economy. California's water and hydropower energy resources are a vulnerable sector that has motivated a series of recent research papers (Madani et al. 2007, 2008; Tanaka et al. 2006; Vicuña et al. 2006, 2008). Hydropower constitutes around 15% of in-state energy generation in California (Aspen Environment and M-Cubed 2005) with a greater proportional value associated with its use predominantly during on-peak periods and its provision of ancillary services to help stabilize the grid. Half of this energy generation occurs at high elevation (over 1,000 feet) in systems that have less storage capacity but higher natural head compared to their lower-elevation counterparts.

A recent study by our research group estimated the impacts of climate change on the high-elevation Upper American River Project (UARP) operated by Sacramento Municipal Utility District (SMUD). This system is located within the Rubicon and Upper American River basins. The model used to simulate the operations of the UARP system was run under four climate change scenarios that were made available for the First Biennial Science Report to the California Climate Action Team, an initiative of the California Environmental Protection Agency (CalEPA) and California Energy Commission.[1] The results of that report, including the study developed by this research group on the impacts on the UARP system, were published in a special issue of *Climatic Change* (Cayan et al. 2008).

In our current research presented in this paper, recognizing some of the limitations of our previous work (Vicuña et al. 2006, 2008), we have introduced three major modifications to the model developed to optimize and simulate the historical and future operations of the UARP system:

1. We modified the objective function of the linear programming optimization routine by changing the energy price representation and by including a value to water storage as a surrogate for power benefits.
2. We changed the analysis of inflow uncertainty in the model by considering a more realistic forecast representation.
3. We modified the approach used to determine future (climate change) operations. This new approach avoids the use of perturbation ratios to develop the future hydrologic scenarios by relying instead on the actual projections of a hydrology model run using the climate change scenarios. This change allows the representation of changes in climate variability as projected by climate change scenarios.

In addition to the study done on the UARP system, we have introduced a second case study, simulating the operations of the Big Creek system operated by Southern California Edison (SCE) under both historical and climate change hydrologic conditions. The Big Creek system is located in the upper San Joaquin river basin in the Southern Sierra Nevada, whereas the UARP system is located in Northern Sierra Nevada. That condition, plus some changes in the system configuration, will provide a more complete picture of the effects of climate change on high-elevation hydropower in California.

[1] www.climatechange.ca.gov/climate_action_team/reports/index.html.

The paper is organized as follows: Section 2 introduces the methodology used to estimate the impacts of climate change on the operations of a high-elevation hydropower system. Section 3 introduces the two cases studies: the UARP and the SCE Big Creek systems. Section 4 presents the analysis of the results associated with the historical and climate change scenarios selected for this work. Finally, Section 5 presents some conclusions.

2.0 Methodological Approach

The following section discusses the new methodological approach used in this work. The major steps involved in this approach include a calibration first of a simulation model of the historical operations and then the study of the effects of climate change using the calibrated simulation model.

2.1. Simulation of Historical Operations

To simulate the operations of the high-elevation hydropower system we constructed an optimization model that uses as input a time series of hydrologic conditions at different inflow locations in the systems and that gives as output detailed operations of the system (reservoir storage, reservoir release through turbines, and reservoir release though spillways or directly to the river) at the daily time resolution.

This simulation model is based on a sequential multi-step linear programming (LP) optimization routine that determines daily operations for the different components of the hydropower system. Two possible objective function configurations are considered to run this model. A first case is called the "energy driven" model; the objective of the optimization routine is to maximize energy generation revenues, restricted to operational constraints (e.g., minimum instream requirements), and physical constraints, such as turbine or reservoir capacity. In a second case, called the "energy and storage driven" model and explained later, we included water storage in reservoirs as part of the objective function. Using an approach developed in Madani et al. (2007) we estimate energy revenues using a continuous piece-wise linear representation of energy prices derived from a distribution of hourly California Independent System Operator (CalIso) prices specific for each month. Five segments are considered in the linearization for each month.[2] This is considered an improvement of our previous work which included only a single on-peak and a single off-peak energy price (following Grygier and Stedinger [1985] and Trezos and Yeh [1987]) developed doing a percentile analysis of the California Power Exchange (PX) data (Appendix A shows the comparison of the LP model formulations under the two energy price structures). The energy price used is a function of the percent time turbines are in operation, assuming they operate at maximum capacity during this time. This facilitates the computations reducing the number of variables needed (just percent time is needed and not percent time and associated flow).[3]

[2] This price data set was chosen in order to be consistent to other modeling efforts that are part of this 2008 Climate Change Impacts Assessment Project (e.g., Medellín et al. 2008). In future model developments we anticipate using different energy price data sets.

[3] This is a realistic approximation, provided that the efficiency of the turbines does not decrease appreciably between the most efficient operating point and maximum capacity.

System operations of a high-elevation hydropower system are based on a variety of factors in addition to electricity generation, including operational releases for peaking and real-time load following (SMUD 2001). The pure "energy driven" model simplifies these aspects by using energy prices as a proxy for all other objectives. Based on the results obtained with this "energy driven" model (presented later) and by discussions we had with UARP system operators, we decided to include a new driver in the system operations that accounted for the value of having water stored in the reservoirs and the ability to transfer this stored water into power capacity that could be used to match peak demand and spinning operations. We called the model with this new objective function the "energy and storage driven" model. The value given to storage is different for each month and could be potentially different for all reservoirs (here though we have used the same value for all reservoirs). These monthly values were calibrated to accurately represent monthly historical operations. Appendix B shows briefly the changes introduced in the objective function by this new structure.

The optimization routine is performed as a series of overlapping moving horizons of 12 months that cover the whole simulation horizon. This approach is similar to the one considered by Hooper et al. (1991). Considering a time horizon of 12 months only limited the amount of hydrologic information available and hence recreated partially the level of uncertainty perceived by real reservoir operators. However if this horizon is kept too short (say one month only) the operations of the LP model, in order to maximize profits, will completely drain reservoirs at the end of the timestep period. The inclusion of the remaining 11 months as part of the objective function is needed to avoid that myopic behavior. We could also avoid this drainage by adding an end-storage function, but it is simpler and effective to extend the timestep period by enough time so that the zero end-storage does not affect storage at the end of the first recorded time period.[4] This "moving horizon" optimization approach is a compromise between a reasonable amount of hydrologic information and simplicity in the objective function formulation, and it will be subject to more analysis in future developments of the model.

The model developed in Vicuña et al. (2008) has within these 12 months a complete knowledge of hydrologic conditions (perfect foresight) at different temporal resolutions. The first of these months was optimized at a daily time step, and the remaining 11 months were modeled at monthly time steps. The use of a daily time step within the first month allowed the assessment of single flood events, which is crucial to the analysis of system operation with regard to undesired spillage. Only the output of the first month was retained; the results of the 11-month model results were discarded and the next time-step performed daily optimization of the "second" month. To better represent the level of foresight of future inflows that the model has (again trying to replicate the level of information that has a real operator), we have made the following changes to the model developed in Vicuña et al. (2008):

[4] We have compared (not shown here) two possible time horizons to determine the amount of time needed to avoid the impact of zero end-period storage on the operations in the early relevant time periods. One of these scenarios considers a one-year time horizon and the other a two-year time horizon. The difference in operations between the two scenarios is less than 0.2%, suggesting that a one-year time horizon (the one used in this study) is sufficient. In future model developments the methodology used in this work will be compared to other methods using longer time horizons and different end-of-period storage water values (e.g., Turgeon 2007).

1. A smaller time horizon for the daily optimization module was included to better reflect uncertainties associated with flood events. The idea was to reduce that foresight to a more reasonable level (five days, instead of a whole month).
2. We reduced the amount of foresight the model is assuming in determining reservoir releases.

As mentioned before the model used to have at the monthly timescale a perfect foresight of 11 months worth of future inflows. During the snowmelt season two to three months of inflow foresight is reasonable (e.g., if the operator is making a decision in April); however, at some other months the only information available for the reservoir operator is that on average flows for a given months (e.g., if the operator is making a decision in October). Here we replicated this level of knowledge by introducing a variable factor that weighs perfect and average inflows to finally estimate the inflow conditions that are available for the LP model at any point in time. If we look at the LP model formulations (Appendix C) under the new configuration, two things change as compared to the base formulation. In the first place $d_{ini}^{j}, d_{last}^{j}$ are not necessary the first and last day within a month but are instead the corresponding initial and final days of a series of consecutive segments of five days that would be used in the daily window of optimization. The second change is with the mass balance equation where now instead of using the perfect foresight inflow (I_i^n) we use a modified time series of inflow conditions that is constructed in the following way.

For a given month *m* and year *t*.

For *n=1:5* (daily window of optimization)

$\mathrm{I}_i^n = \mathrm{I}_i^{t,m,d}$ (actual inflow conditions for year *t*, month *m*, and day *d*)

For *n=6-17* (sub-monthly and monthly window of optimization)

$\mathrm{I}_i^n = \mathrm{I}_i^{t,m} * (w_m^s) + \overline{\mathrm{I}}_i^m * (1 - w_m^s)$ (weighted average of actual flows for a given month and year and average inflow conditions for that particular month).

The weighing factor w_m^s is a function of the initial month of the time series (month *s*) and the month in which we are doing the forecast. This factor changes over time to reflect the better forecast of inflow conditions available at different points in the year. For example w_m^s in October (month *s*) is equal to 0 for all months to reflect a complete uncertain scenario, whereas w_m^s when *s* is May would be close to 1 to months during the snowmelt season (*m*=June, July, August, September) but then 0 afterwards.

This new formulation represents more realistically reservoir operations under uncertainty and offers a better test to assess the impacts associated with climate change, especially those related to the change in flood events frequency and magnitude.

2.2. Development of Future Climate Change Scenarios

The optimization model introduced in the previous section with its new methodology accurately represents historical reservoir operations. This calibrated model is used to estimate the impacts that climate change could have on the following detailed operating variables:

- Minimum stream flows. The model is used to determine how often minimum stream flow requirements are controlling operations in the reservoir system. In future studies these requirements could be modified to represent different regulation environments.
- Outflow of the high-elevation system onto the valley floor. For example in the case of the UARP system, Folsom Reservoir is located just downstream of the last reservoir that composes this UARP system, whose releases affect the inflows into this important piece of the Central Valley Project (CVP) system. The model simulates conditions at a daily level so it could be used for example to estimate future changes in flooding conditions that could affect this reservoir's operations and the city of Sacramento.
- Spills[5] and other reservoir operating variables. A detailed model such as this one, based on principles such as water balance but considering detailed constraints and operating characteristics, could be used to simulate changes in a set of different relevant operating variables. For example the model could be used to estimate power capacity (as compared to energy generation) in critical summer months.

To represent changes in future hydrologic variability we are using instead of a perturbation ratio approach (Vicuña et al. 2007; Vicuña et al. 2008) direct time series of hydrologic conditions as projected by the variable infiltration capacity (VIC) hydrology model run by a given climate change scenario. The difference in these two approaches is shown in Appendix D. Using an approach that does not rely on the perturbation ratios is beneficial because the effects of changes in the interannual variability of climatologic and hydrological variables could be studied with such an approach (Purkey et al. 2008). The disadvantage is that one has to do a "backcast" of modeled historical operations to ensure that the VIC model did not introduce a bias into the inflows (e.g., too high, too flashy, or too early).

For the specific impacts associated with hydropower operations, the use of a direct hydrology approach allows the exploration of the transient and progressive effects of climate change. This capability is critical when answering questions about the time frame in which operations (or forecasting schemes) should be altered, based on the already-visible effects on hydrologic conditions.

All the above are the benefits of using a detailed water-based model such as the one developed in this project.

[5] In this assessment, the term *spills* considers all flows not passing through turbines, so that includes stream flow requirements.

3.0 Case Studies: Upper American River Project and Big Creek System

The project's focus is to study the operations under historical and climate change hydrologic conditions of high-elevation hydropower systems using an optimization model that includes details about the system configurations and constraints. As case studies of this project we have selected two high-elevation systems in California: the Upper American River Project (UARP) and the Big Creek system. The UARP is located in the Upper American and Rubicon basins (headwaters at 9,900 ft [≈ 3,000 m]) and operated by SMUD; the Big Creek system is located in the upper San Joaquin basin (headwaters at 14,000 ft [≈ 4,200 m]) and operated by SCE. Figure 1 presents a map showing the location of both systems.

The UARP system was constructed between 1957 and 1985. It includes 11 reservoirs that can impound over 425,000 acre-feet (ac-ft) of water, eight powerhouses that can generate up to 688 megawatts (MW) of power, and about 28 miles (45 kilometers, km) of power tunnels/penstocks. The system is located above CVP's Folsom Dam. Annual runoff to the UARP system is roughly 1,000 thousand acre-ft (TAF). The project is currently in a Federal Energy Regulatory Commission (FERC) relicensing stage, and thus sufficient data were publicly available to conduct the case study. The project is composed of seven separate developments, and Table 1 presents a summary with the major characteristics of these developments.

The Big Creek system is one of the largest and oldest high-elevation hydropower systems in California, consisting of 9 power generation plants for a total generation capacity of approximately 1,000 MW and about 54.3 miles (87.4 km) of power tunnels/penstocks. The Big Creek system has a storage capacity of 560 TAF distributed within six major reservoirs located within the upper San Joaquin river watersheds. The system is located above Pacific Gas and Electric's (PG&E's) Kerckhoff reservoir and hydropower station and CVP's Millerton Lake. Annual runoff to the Big Creek system is roughly 1,800 TAF. Big Creek System accounts for 90% of SCE's hydropower resources. The project is also under a FERC relicensing process, and it is composed of nine separate developments. Table 2 shows a summary with major characteristics of these developments.

As can be seen from the data presented in Tables 1 and 2 and above, the UARP and Big Creek posses those characteristics typical of a high-elevation hydropower system (Aspen Environment and M-Cubed 2005). Elevation of the components in both cases are above 1,000 ft (higher in the case of the Big Creek). And in both cases the storage to runoff ratio is relatively small: 0.4 (425 TAF/1,000 TAF) and 0.3 (560 TAF/1,800 TAF) in the case of the UARP and Big Creek systems, respectively. Finally, with the exception of Union Valley in the UARP system, the reservoir depth is a small fraction of the head, so the nonlinearities of the "head effect" that often complicate hydropower optimization can be safely ignored in the model.

Table 1. UARP system components included in the model

	COMPONENT						
PARAMETER	Loon Lake	Robbs Peak	Union Valley	Jones Fork	Jaybird	Camino	White Rock
Elevation (ft)	6,410	5,231	4,870	5,450	4,450	2,915	1,850
Head (ft)	1099	361	420	581	1535	1066	856
Reservoir Capacity (TAF)	79	1.3	277	46	3.3	0.82	17
Reservoir depth (ft)	165	21	360	52	141	76	186
Depth/Head	15%	6%	86%	9%	9%	7%	22%
Penstock capacity (cfs)	999	1,249	1,576	291	1,344	2,099	3,948
Capacity (MW)	82	29	46.7	11.5	144	150	224

Table 2. Big Creek system components included in the model

	COMPONENT								
PARAMETER	Portal PH*	Big Creek No. 1	Big Creek No. 2	Big Creek No. 2A	Big Creek No. 3	Big Creek No. 4	Big Creek No. 8	Eastwood PS	Mammoth Pool PH
Elevation (ft)	7,643/ 7,328	6,950	4,810	5,370	2,230	1,403	2,943	6,670	3,330
Head (ft)	230	2,131	1,858	2,418	827	418	713	1,338	1,100
Reservoir Capacity (TAF)	125/64	89	0.06	136	0.99	26	0.05	1.5	120
Reservoir depth (ft)	18	95	15	64	46	55	5	38	205
Depth/Head	8%	4%	1%	3%	6%	13%	1%	3%	19%
Penstock capacity (cfs)	715	678	467	654	3,265	3,437	1,305	2,303	2542
Capacity (MW)	10.8	88.2	66.5	46.7	174.5	100	75	200	190

* The Portal PH system is composed of two reservoirs: Lake Thomas A. Edison and Florence Lake. That is the reason why we present two elevations and two reservoir capacities in this case.

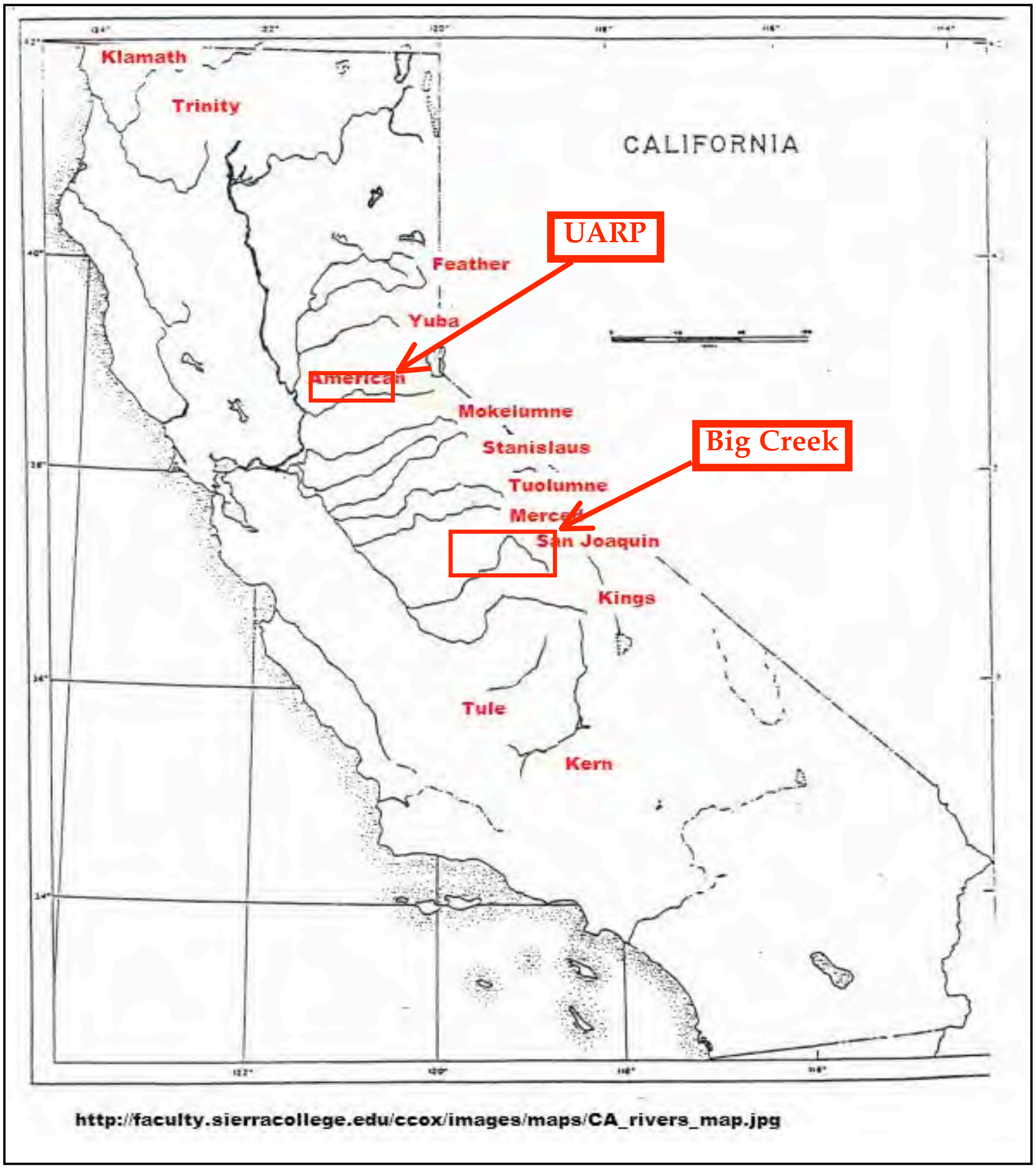

Figure 1. Location of UARP and Big Creek systems

4.0 Results

4.1. Historical Operations Results and Analysis of Changes Introduced

To simulate historical operations of the UARP and Big Creek systems we used as input time series of daily inflows into the set of reservoirs that compose both systems. In the case of the UARP system the time period covered was 1985–2000, whereas in the case of the Big Creek system the period covered was 1982–2002.[6] Figure 2 shows the interannual variability of hydrologic conditions in both the UARP and Big Creek systems. It shows a similar pattern of annual runoff in both systems but with a different magnitude.

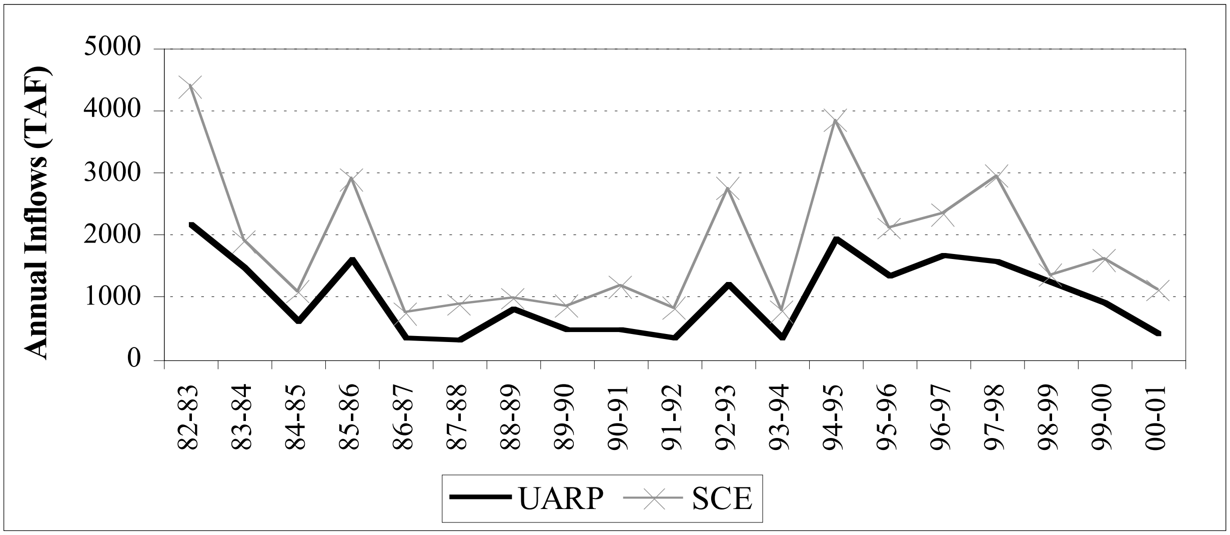

Figure 2. Annual runoff into the UARP and Big Creek systems

The historical operations for both systems were simulated using the LP optimization routing explained in Section 2. As explained before we considered two different objectives to determine these operations. In one case the objective function considers only energy generation revenues (the "energy driven" model); in the other the objective function considers both energy revenues and storage value (the "energy and storage driven" model). To exemplify the differences between these two alternative configurations we present a summary of the UARP system's operations in the following set of figures. We first pay attention to the results on energy generation, where the results are compared with historical conditions. Figures 3 and 4 show the comparison between energy generation on an annual basis and on a monthly basis (as a percent of total generation) for three cases:[7]

- Actual historical.
- Modeled historical under the energy driven model.
- Modeled historical under the energy revenues and storage value drivers.

In Figure 3 showing the monthly pattern of generation we have included as well the monthly average energy prices. We also compare the energy pattern resulting from this study with that of another study, using a different methodology in 2008 Climate Change Impacts Assessment Project (see Madani et al. 2007; Medellín et al. 2009). In Figures 5, 6, and 7 we show average

[6] These data sets were provided by SMUD and SCE, respectively.

[7] In order to minimize the number of redundant figures we present here results only for the UARP system even though similar modeling improvements were made to the Big Creek system (Vicuña et al. 2007; Vicuña et al. 2008).

monthly and annual spills and average monthly end-of-month storage for all reservoirs, respectively, comparing the two structures of objective formulations.

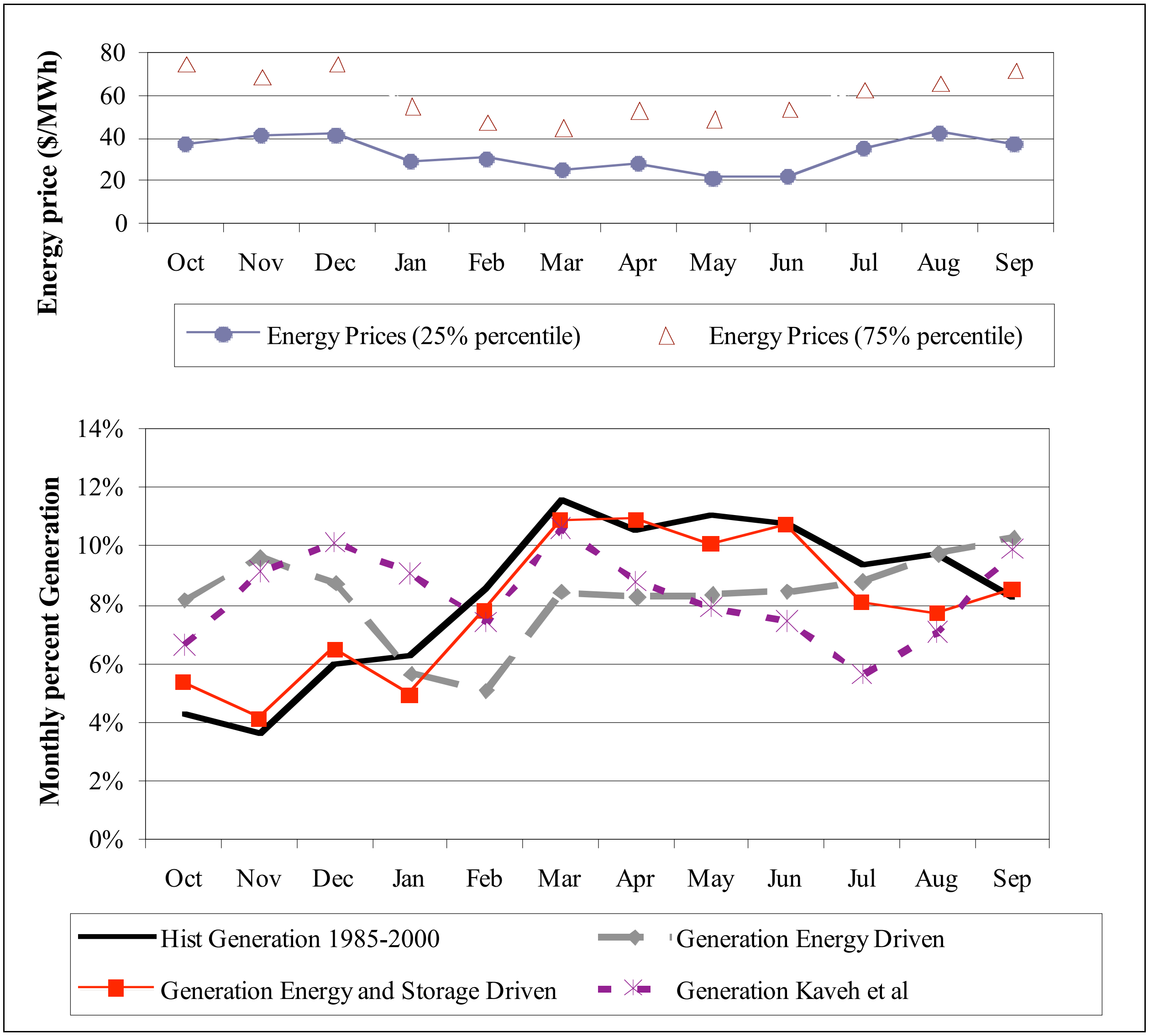

Figure 3. Comparison between historical and modeled monthly percent energy generation in the UARP system

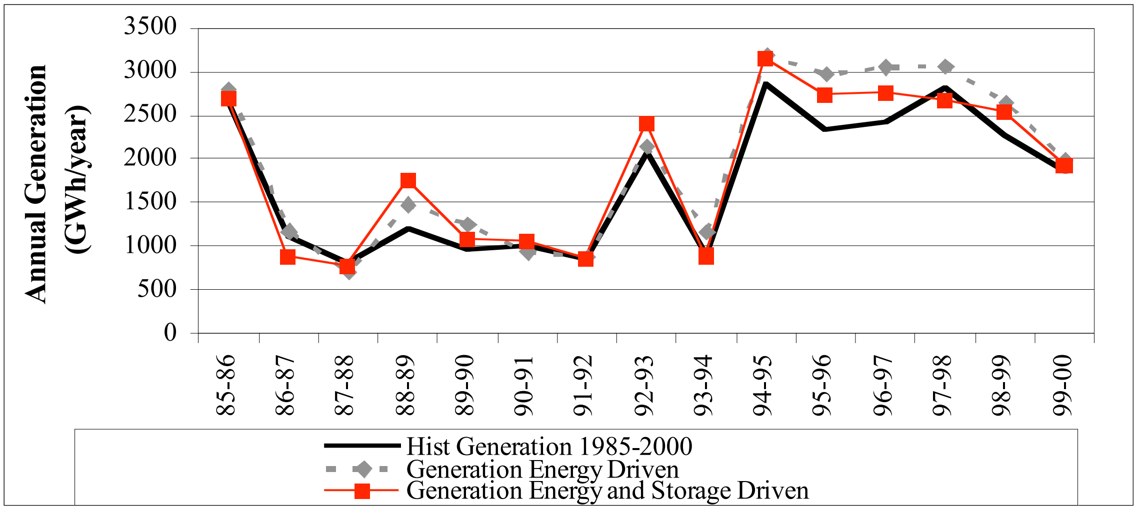

Figure 4. Comparison between historical and modeled annual energy generation in the UARP system

As can be seen from the results shown in Figure 3, the model driven purely by energy revenues is not representing accurately energy generation (the only variables available for comparison) at either the annual scale (model over predicts generation) or the monthly scale (where there is too much generation in the winter months and too little in the spring months). The generation pattern follows a pattern that is close to the monthly pattern of energy prices (also shown in the figure in the upper panel) considered in this study (see Section 2.1 for a discussion of the energy price data set used). Looking at the historical pattern of generation it appears that this driver (energy prices) alone is not sufficient to represent historical operations. An "LP-fixed head" optimization model driven purely by energy prices, has little incentive to fill reservoirs. Energy generation in the long term is maximized by keeping reservoirs as empty as possible. With a close-to-empty reservoir, it is much easier to handle spills, which are reduced in most of years to just comply to minimum stream flow requirements (see Figures 5 and 6 for the energy-driven case) (remember that in this assessment the term *spills* considers all flows not passing through turbines, so that includes stream flow requirements.) With a reduction in spills, water passing through turbines is enhanced, and so energy generation is higher than it is under historical conditions.

The results are improved by including storage calibration values, as needed to represent objectives other than energy revenues. These storage values are determined from a calibration exercise, and should not be interpreted as shadow energy capacity values for these hydropower systems. These storage values could be thought as soft constraints put on storage levels at different months during the optimization routine. Table 3 presents the calibration values assigned for the Big Creek system reservoirs. Including these values in the model tends to increase reservoir storage (compare the two scenarios in Figure 7), induce higher spills (Figures 5 and 6), reduce energy generation (Figure 4) and shift generation to months with lower energy prices (especially spring months). There is still a slight overprediction in generation, which is probably due to:

- an underprediction of spills (attributed to a better prediction of flows and the damping effect of considering a time resolution of daily instead of hourly for example), and
- an overestimate of the generation capacity of the power plants, especially in regards to generation efficiency.

Table 3. Calibration storage values for the Big Creek system (in $/AF)

Month	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Value	4	11	11	7	5	5	5	350	500	0	0	0

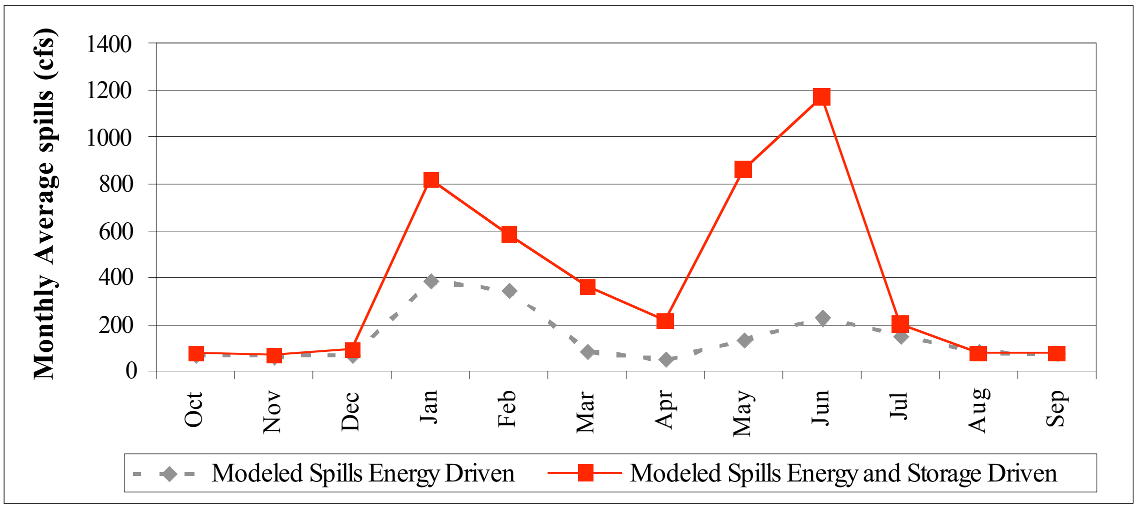

Figure 5. Average monthly spills (TAF) in the UARP system

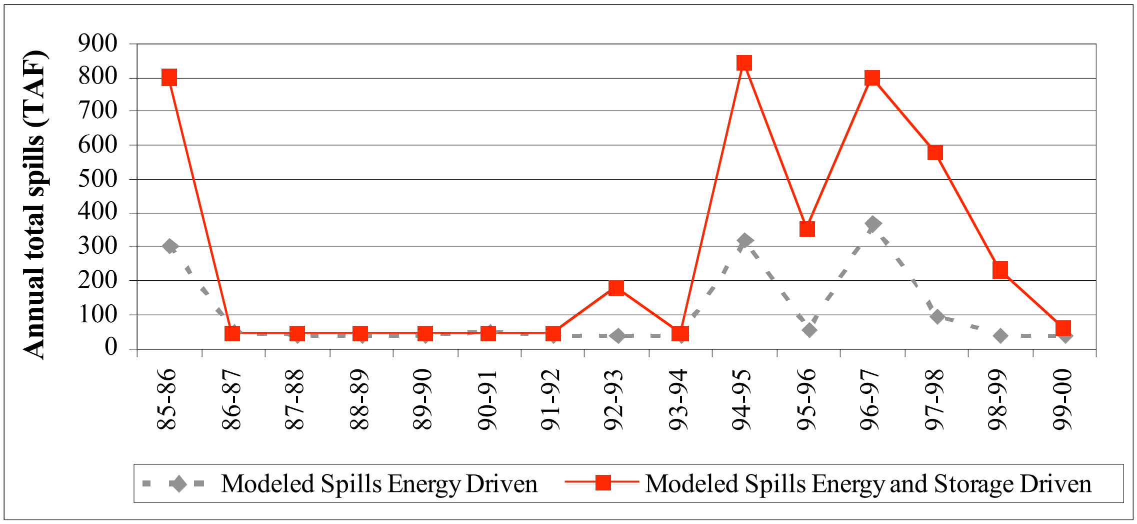

Figure 6. Annual spills (TAF) in the UARP system

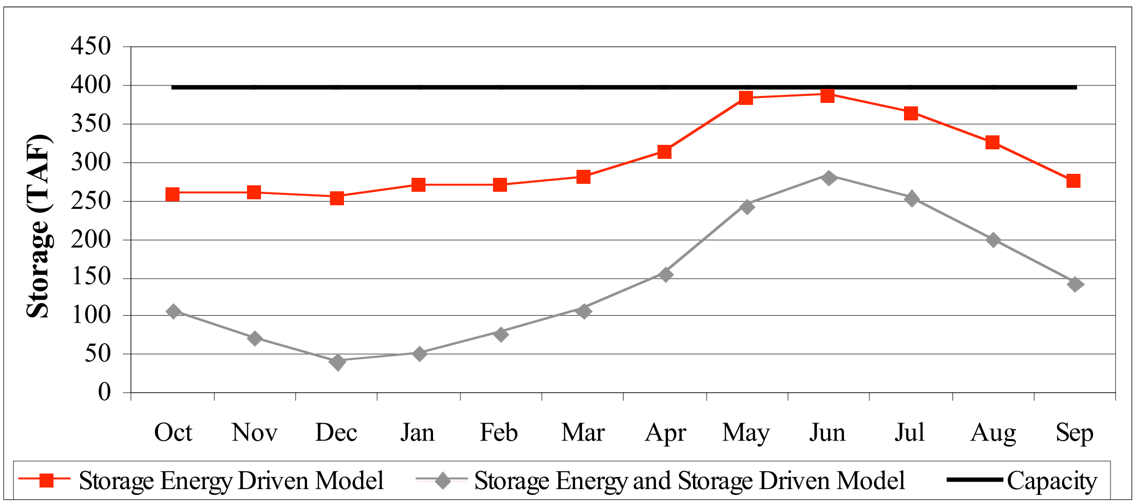

Figure 7. Average end of month storage for the whole system (TAF) in the UARP system

In the case of the Big Creek system simulations we also considered a storage value as part of the LP objective function. After calibrating this storage value we obtained operations that agreed well with the historical operations of this system, as can be seen in Figures 8 and 9. These figures compare monthly average and annual energy generation of the Big Creek system.

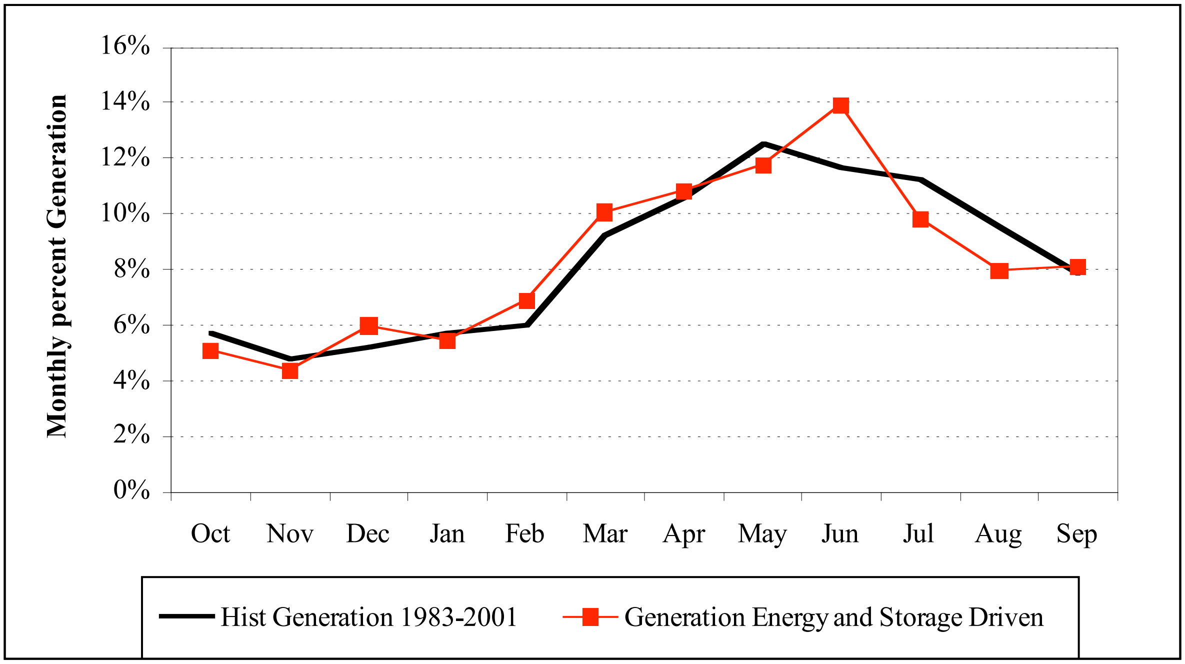

Figure 8. Comparison between historical and modeled monthly percent energy generation in the Big Creek system

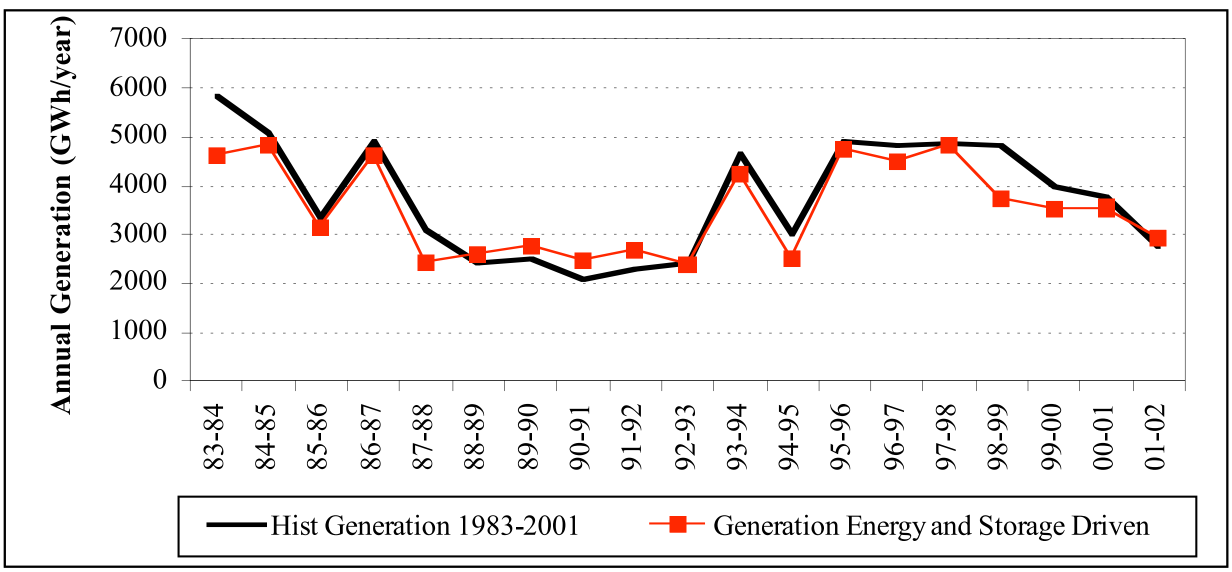

Figure 9. Comparison between historical and modeled annual energy generation in the Big Creek system

4.2. Climate Change Results

The 2008 Climate Change Impacts Assessment is in charge of providing the climate change scenarios to be used in the studies that are part of the Second Biennial Science Report to the

California Climate Action Team. A description of the initiative and the work done to make available the set of climate scenarios can be found in the group's website.[8] General circulation model (GCM) output data was statistically downscaled using two approaches: the Bias Correction and Spatial Downscaling (BCSD) approach and a Constructed Analogues (CA) downscaling approach. A comparison of both methods can be found in Maurer and Hidalgo (2008). The CA requires GCM output that was not available for all scenarios considered in the project. In order to include the largest possible range of scenarios we have chosen to use the BCSD downscaled datasets. All the scenarios used in this work (listed in Table 4) were previously run through the VIC hydrology model.[9] From the set of grids that span the spatial resolution of VIC in the Sierra Nevada we selected a subset that completely enclosed the boundaries of the UARP and Big Creek systems' watersheds. We next used the methodology explained in Section 3 (and in more detail in Appendix D) to develop first scaling factors between historical streamflow at different inflow points in both systems and historical runoff represented by VIC based model simulations and then time series of future hydrologic conditions for the two systems for each one of the climate change scenarios. An example of the comparison between the observed historical and "VIC-based historical" simulations for the streamflow of the Rubicon system at UARP is presented in Figure 10. According to the results presented in this figure it appears that the VIC modeling of these basins results does not accurately reproduce very low and very large runoff conditions. The differences though are not large and the bias should also occur in the future simulations. Since the goal is to compare results between the VIC-based historic and future operations and not between the historic recorded and VIC future conditions, the conclusions are in the right direction and have the right magnitude.

[8] http://meteora.ucsd.edu/cap/scen08.html.

[9] The variable infiltration capacity (VIC) model is a macroscale, distributed, physically based hydrologic model that balances both surface energy and water over a grid mesh. It has been successfully applied at resolutions ranging from a fraction of a degree to several degrees latitude by longitude. A description of the hydrologic model VIC can be found in Nijssen et al. (1997).

GCM	Emission scenarios[10]	
CNRMCM3	B1	A2
GFDL CM21	B1	A2
NCAR PCM1	B1	A2
MIROC32MED	B1	A2
MPIECHAM5	B1	A2
NCARCCSM3	B1	A2

Table 4. Climate change scenarios used in the analysis

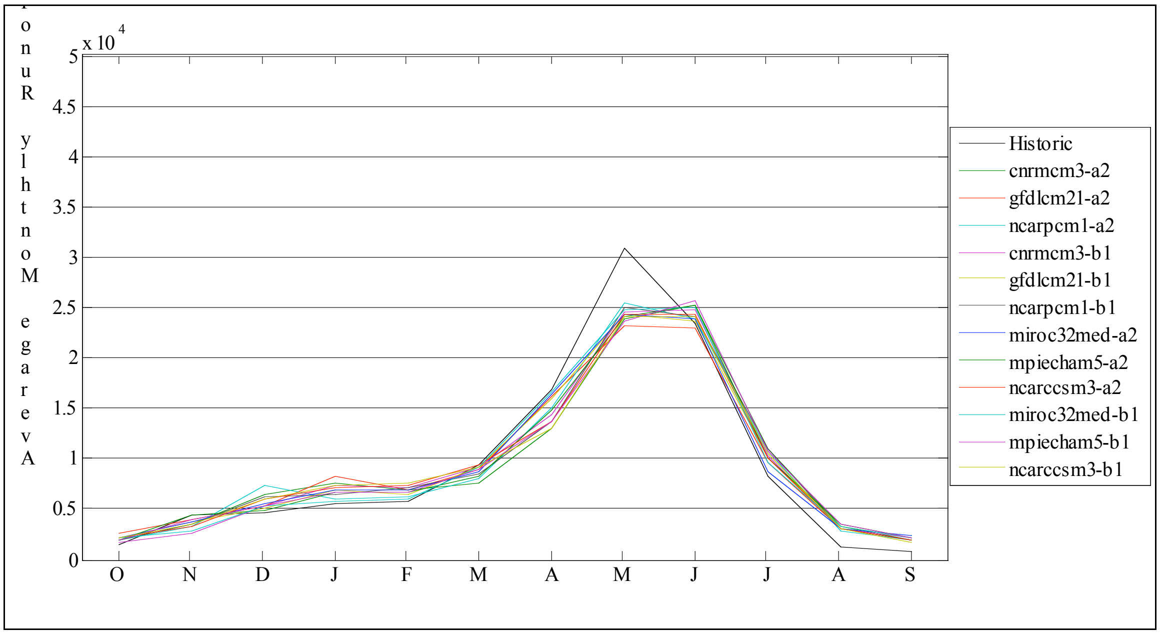

Figure 10. Comparison between the measured historical and "VIC-historical" streamflow for the streamflow of the Rubicon system at UARP

Table 4 summarizes the main characteristics of the scenarios developed by comparing the following metrics for four different periods: historical (1974–2010), as represented by the VIC model-based climate change scenario; Early twenty-first century (2011–2040); Mid twenty-first century (2041–2070); and Late twenty-first century (2071–2100). To simplify the presentation we show the average of the actual value for the historical period and the different climate

[10] A2 and B1 are two of the future carbon emissions scenarios developed by the Intergovernmental Panel on Climate Change in its *Special Report on Emissions Scenarios* (SRES). A2 reflects a future with relatively high CO_2 emissions, while B1 reflects a future with lower CO_2 emissions. The climate change scenarios considered in this study were selected in an attempt to bracket the uncertainty existing among models on California climate change climatic predictions. A description of the scenarios used in this work can be found on the California Climate Change Center website at http://meteora.ucsd.edu/cap/.

scenarios for the different variables. To show the change for early, mid, and late periods we show both the average and range of the relative comparisons for the different scenarios. The following variables are shown:

- Average annual runoff
- Average March through September (typical snowmelt plus summer season) percent of annual runoff
- Average December through February 90th percentile daily flows (indicating floods occurring during winter months)

The hydrologic scenarios showed in Table 5 present us with the following future conditions:

- Consistent with previous work done in California, this analysis shows there is uncertainty in terms of the overall amount of water that could be flowing through the system. Both systems show a slight decrease in annual inflow for the early part of the century taking the average conditions for all projections. By mid century this runoff reduction is more obvious, and in the case of the UARP system a reduction is projected for almost all of the scenarios (with just one showing just a slight increase in inflows). By the end of the century the uncertainty is still very large (particularly for the Big Creek System), and the magnitude of the runoff reduction is even larger when averaging over all scenarios. Another important observation to make with regards to the change in the amount of water flowing through these systems is that the projections show larger reductions in the Big Creek system than in the UARP system. This is a consistent result with the projected changes in climatic conditions in Northern and Southern California (see the California Climate Change Center website, at http://meteora.ucsd.edu/cap/).
- In terms of runoff timing there is a clear reduction of the snowmelt season and summer runoff, consistent with the notion that increasing temperatures modify the timing of streamflow toward earlier in the water year (Vicuña and Dracup 2007). This trend is seen in all of the scenarios and for all time periods (with the exception of one scenario in the early twenty-first century for the UARP system, which shows a slight increase in snowmelt season runoff as a percent of annual runoff). This can be verified by looking at Figure 11, which presents average monthly runoff for both systems and the four different time periods. Again we see that, although the direction of this trend is the same in both systems, the magnitude of the change is larger in the UARP system than in the Big Creek system. In the case of the UARP system, and considering an average over projections, we see that under historical hydrologic conditions almost 70% of runoff flows during the typical snowmelt season. This number is reduced by more than 20% in average for all projections. So future hydrologic conditions in the basins feeding the UARP system show that around 55% of runoff occurs during the months from March through September. The conditions for the Big Creek system in contrast show that the snowmelt season runoff represents almost 90% of annual runoff under historical conditions, and that number is reduced to slightly above 75% under future (end of century) projections. It is interesting to note that that number is still above current conditions for the UARP system. Considering that there are no significant differences in temperature projections for both regions, this difference in hydrologic pattern can be attributed only to the difference in the elevation of both systems (the southern Sierra Nevada mountains being

higher than the northern counterparts).[11] This has been a typical result for studies done in California in terms of differences in the response of the two regions for the changes in temperature levels.

- And finally on average all scenarios show an increasing trend in extreme flows during the winter months. This is an expected result associated with the projections in temperature increase but that could be compensated in some cases with a reduction in precipitation and runoff. That is why in some of the scenarios there is a reduction in winter extreme flows. By the end of the century, however, even with the largest reductions in flows that are projected by that time, the increase in temperature is enough to increase extreme runoff in all scenarios. Again due to its higher elevation, the Big Creek system has under historical conditions smaller extreme flows during the winter months even though it has a larger amount of water flowing through the system as compared to the UARP system. But this system also experiences a larger increase in these flows under the projected future scenarios. It is expected that this increase in extreme flows for both systems could impede their operations during winter months and increase the amount of undesired spills occurring.

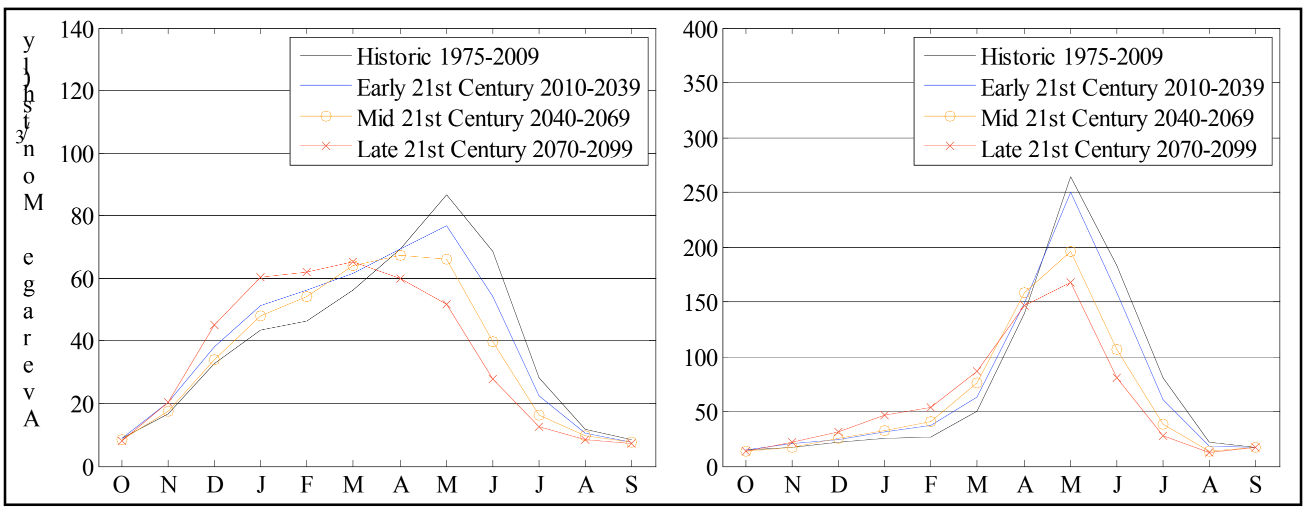

Figure 11. Changes in monthly hydrologic conditions in UARP and Big Creek systems

Table 5. Comparison of hydrologic conditions for different time periods and the two hydropower systems considered in this study. The actual value is shown for the model-based historical period and the average plus a range is shown in percentage change for future periods.

[11] It has been suggested also that this difference is partly related to the higher recurrence of storms hitting the UARP system as compared to the Big Creek system.

Variable	Period	System	
		UARP System	Big Creek System
Annual runoff in TAF (mill m^3)	Hist	1,004 (1,238)	1,808 (2,229)
	Early	-0.3 % (-22 % / 21.6 %)	-1 % (-25.6 % / 21.8 %)
	Mid	-9.3 % (-34.9 % / 0.6 %)	-14.1 % (-49.3 % / 8.9 %)
	Late	-10.1 % (-24.5 % / 16.4 %)	-17.8 % (-39.9 % / 21.3 %)
Percent runoff during snowmelt season (%)	Hist	68.9%	87.8%
	Early	-8 % (-16.2 % / 0.3 %)	-3.4 % (-7 % / -0.1 %)
	Mid	-9.5 % (-15.1 % / -1.4 %)	-6.4 % (-12.1 % / -1.2 %)
	Late	-21.3 % (-32.9 % / -15.2 %)	-13.8 % (-28.5 % / -6.3 %)
Average 90th percentile flow during winter months in cfs (m^3/s)	Hist	1214 (34)	704 (20)
	Early	12.4 % (-7.1 % / 36.2 %)	24.1 % (-3.7 % / 60.5 %)
	Mid	7.5 % (-10.9 % / 31.5 %)	25.9 % (-18.3 % / 61 %)
	Late	24.1 % (10.4 % / 53.7 %)	70.7 % (15.3 % / 147.7 %)

To present the impacts that these climate change scenarios could have on the operations of the UARP and Big Creek systems, we ran the calibrated energy and storage driven optimization model as before. It is unclear at this point how well the storage values assigned for historical calibration, as described in the previous section, allow for accurate simulation of future climate change—particularly given the likely changes in future political/economic and physical constraints on the system. Nevertheless the authors believe that the approach used in this paper does illustrate potential climate impacts and can help guide future water resources management. From these runs we selected the following key variables:

- Annual and monthly energy generation and associated revenues
- Average August system capacity (a measure of the ability of the system to meet peak demands by the end of summer)[12]
- Annual and monthly spillage
- Downstream release (to Folsom and Millerton dams)

Table 6 summarizes the output for the first three sets of variables for all scenarios and time periods. The presentation format is similar to the case that shows the projected hydrologic conditions. For each of the variables considered we first show the average value for the historical period. Then, for each of the future time periods, we show the average change (the percent change from historical conditions) and the range based on the results from all scenarios.

[12] *Capacity* is defined as end of the day energy generation capacity in the system, taking into account head effects and assuming average turbine efficiency.

Table 6. Comparison of different system outputs for different time periods and the two hydropower systems considered in this study. The actual value is shown for the model-based historical period and the average plus a range is shown in percentage change for future periods.

Variable	Period	System: UARP System	System: Big Creek System
Energy Generation in GWh/year	Hist	1,976	3,580
	Early	-2.1 % (-19.9 % / 14.9 %)	-0.6 % (-14.2 % / 23.2 %)
	Mid	-8.2 % (-31.3 % / 0.2 %)	-8 % (-38 % / 3.3 %)
	Late	-12.2 % (-25.1 % / 7 %)	-10.4 % (-26.8 % / 17.4 %)
Energy Generation revenues in mill $/year	Hist	130	212
	Early	-1.3 % (-14.5 % / 10.8 %)	0.7 % (-11.3 % / 26.4 %)
	Mid	-5.8 % (-23.1 % / 2.2 %)	-4.7 % (-33 % / 9.6 %)
	Late	-8.5 % (-18.5 % / 5.2 %)	-7.8 % (-23.4 % / 17.2 %)
Average August Power Capacity in MW	Hist	654	1,034
	Early	-0.2 % (-0.6 % / 0.1 %)	-0.1 % (-0.2 % / 0 %)
	Mid	-0.2 % (-0.6 % / 0.3 %)	-0.1 % (-0.3 % / 0.1 %)
	Late	-0.1 % (-0.6 % / 0.2 %)	-0.2 % (-0.6 % / -0.1 %)
Average Spills in cfs (m^3/s)	Hist	269 (8)	3,447 (98)
	Early	19.2 % (-43.4 % / 96.1 %)	-0.5 % (-31.9 % / 26.5 %)
	Mid	-1.8 % (-59.5 % / 49.5 %)	-17.3 % (-56.1 % / 13.1 %)
	Late	10.8 % (-27.2 % / 104.5 %)	-21.8 % (-48.3 % / 25 %)

Several conclusions can be derived from the results presented in Table 6. First we can see that in average there is a reduction in the energy generation and the associated revenues that can be obtained from the operation of these systems. There is however a large uncertainty in the results, with some scenarios showing an increase in energy generation benefits. This uncertainty is smaller at mid century, where most scenarios show a reduction in benefits. Similar to the conclusions derived in Vicuña et al. (2008) we can see also that the reduction in revenues is smaller than the reduction in energy generation. This is explained by the fact that with a reduction in flows there is larger storage capacity available in the system to "move" the water to when it is more valuable (e.g., summer months).

A series of additional figures help illustrate the impacts on the operations of these systems from changes in the hydrologic conditions. In Figure 11, we compare for all scenarios and for the last time period (late twenty-first century) the changes (as compared to historical values) in annual runoff with annual changes in annual energy generation and annual revenues. In Figure 11 we have also included the best fit linear relation for all four data sets, with the main properties of these relationships presented in Table 7.

Figure 11 shows a series of interesting results. First we corroborate here that there is a clear positive relationship between changes in energy generation and revenues and changes in system runoff. The R^2 of the linear correlations for the four data sets presented in Figure 11 is above 0.92 for all cases. So in all four cases the change in annual runoff is a large predictor of the change in system energy generation and revenues associated.

It is interesting though to note here some subtleties in these assertions. First, for both systems, the coefficient for the relation between energy generation and runoff is greater than the coefficient for the relation with revenues and runoff. This shows again the ability of the system operations to move water throughout the day and year, to increase the ability to generate at times when energy is more valuable. We see also that the coefficients for the UARP system are smaller than the coefficients for the Big Creek system, for both types of relations. This means that for a given change in annual runoff, the UARP system has associated a larger reduction in annual generation and revenues than the Big Creek system. This result is attributed to the fact that the hydrologic changes (in terms of pattern changes) in the UARP system are larger than those affecting the Big Creek system, as was already mentioned. The projected hydrology in the UARP system is more “inconvenient,” with more water flowing in months when it is not needed (winter months) and less when it is needed (late spring and summer months).

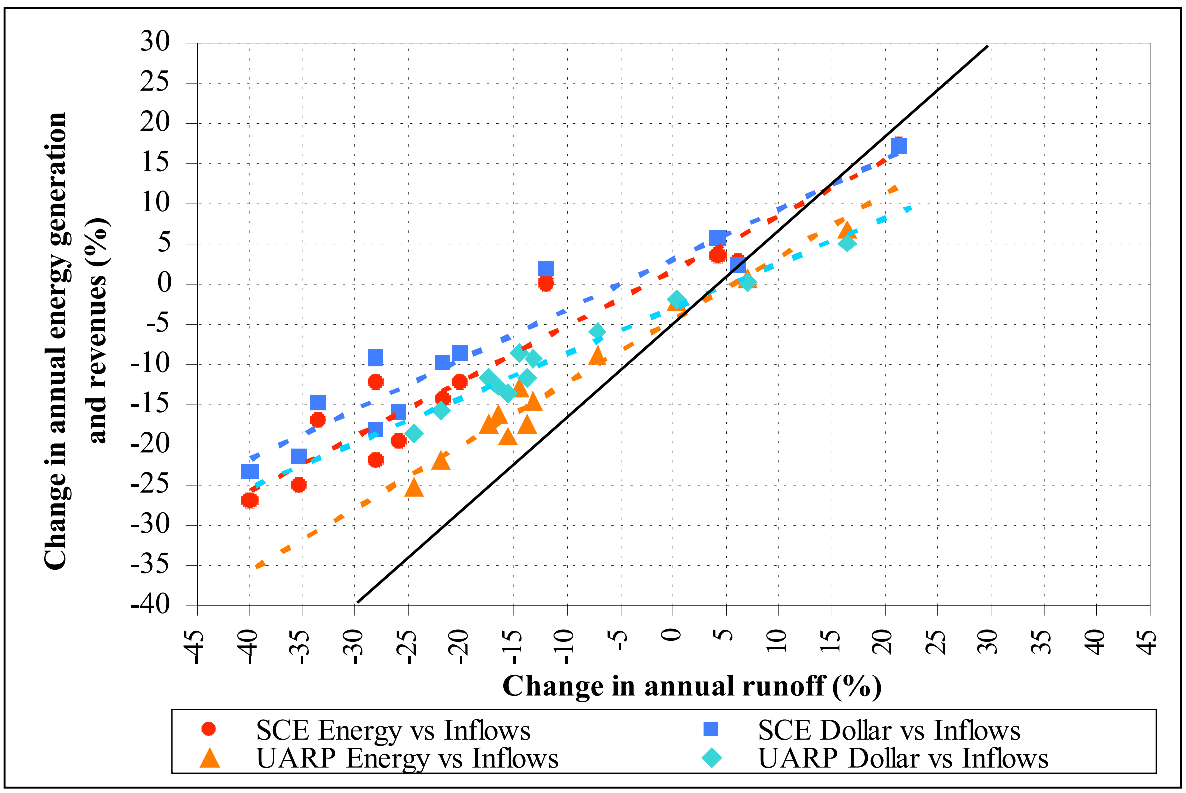

Figure 11. Comparison between changes in hydrologic conditions and UARP and Big Creek system outputs

Table 7. Summary of linear correlations between changes in annual runoff and system outputs

Variable	UARP System		Big Creek System	
	Energy vs. Runoff	Revenues vs. Runoff	Energy vs. Runoff	Revenues vs. Runoff
R^2	0.97	0.96	0.93	0.92
Coefficient	0.78	0.56	0.69	0.62

The inconvenience of this projected hydrology is evidenced with changes in the system operations that can be verified in the charts presented in Figure 12. In these charts we compare three main systems operation variables: reservoir release through turbines, spills, and storage at the monthly level for three different time periods (historical, early twenty-first century, and late twenty-first century). The figure shows that both systems have a comparable timing of reservoir release through turbines, with the exception that they tend to be larger in early spring months in the UARP case.

However, the timing of spills is clearly different in both systems. Under historical conditions, spills during winter months are quite larger in the UARP system than in the Big Creek system—the latter having most of their spills concentrated during the spring and summer months. This difference is even larger under the climate scenarios, especially by the end of the century, when the UARP system experiences the most spills during the winter months but the Big Creek system still has them concentrated during the spring and summer months, and at a smaller magnitude than under historical conditions. So in the case of the UARP system, the larger change in timing of runoff increases the occurrence of spills in winter months and that explains why there is a larger reduction in energy generation and revenues.

It also interesting to note in Figure 11 that this change in runoff timing affects UARP system operations by reducing the relative increase in revenues associated with runoff increases. This can be checked by looking for those scenarios that have an increase in runoff. The markers representing the changes in outputs for those scenarios are below the 45° line, indicating that the changes in output are smaller than the changes in runoff. We see also that the linear relation between revenues and runoff in this system is weaker than the relation between energy generation and runoff in this system. The difference between the coefficients of those relations (see Table 7) is larger than the difference existing in the case of the Big Creek system. In the case of that system, for most scenarios (with the exception of the driest), the increase in revenues is larger than the increase in runoff.

Finally we can see that reservoir storage is kept at similar levels under all different time periods. The impacts of climate change in both systems are reflected by an increase in storage during the late winter and early spring months and a slight reduction during the late spring and summer months. This last reduction is more evident in the case of the Big Creek system, due to the larger reduction in runoff, as projected for this system. These results reflect the great flexibility that a high-elevation hydropower system has in managing its reservoir inflows. Not having flood control rules attached to its management operations allowed these systems to deal very effectively with changing inflow conditions by changing the timing of when reservoirs are being refilled and emptied.

With regard to the capacity of these hydropower systems to generate energy when the demand is at its peak levels (summer months), we can see that the new hydrologic conditions basically remain unaltered. The average system power capacity in August is reduced 0.6% at the most. A reason behind this insensitivity is that these high-elevation systems have a large proportion of their available head fixed (that is, they use the gradient in the terrain as the available head), independent of storage at the reservoirs.

The results presented are only for the month of August, which typically has the largest load for energy in California. This demand is mainly determined by the occurrence of extreme hot days or heat waves (Miller et al. 2008). An increase in temperature levels should increase the occurrence of extreme hot days in several regions in California and thus affect the energy load demand (Miller et al. 2008; Hayhoe et al. 2004). One of the effects of these changes in terms of the operation of a high-elevation hydropower system could be an extension of the number of months when the load is at maximum levels.

Figure 13 shows the effect that this could have on both the UARP and Big Creek systems, presenting a comparison of the percent time (number of days) within a month that temperature levels indicate the occurrence of a heat wave (defined as a day with temperatures above historical 95th percentile, and the percent time where system power capacity is above the 99% percent level.[13] This information is presented for four cases: historical and late twenty-first century for the UARP and Big Creek systems. For each one of these cases we present the analysis for the months from May through September, and in each case we show the average for all 12 scenarios as well as the range in the conditions.

Figure 13 illustrates that both systems do not have problems supplying energy during peak demand periods from May through July, given historical energy prices and peak demand. In August and especially in September we see that the Big Creek system would face a situation where the number of days with heat waves in the future will exceed the number of days the system is at peak capacity. The UARP system is expected to have fewer problems than the Big Creek system meeting this change in peak demand capacity in August. In September, however, the range of heat wave percentages overlaps the range of peak system capacity. Based on these results we can conclude that these two systems should not have problems meeting peak power demands in the late spring and early summer, even with an increase in power demand associated with increased occurrence of heat waves. However, if there is an increase in heat waves later in the summer, these two systems (especially the Big Creek system) would have trouble meeting peak demand unless extra water is stored in reservoirs, reducing even further the amount of energy being generated (due to increased spills)

[13] It is important to note that a 99% percent level is a very stringent constraint. The simulation of system operations is shown to be robust at smaller commitment levels.

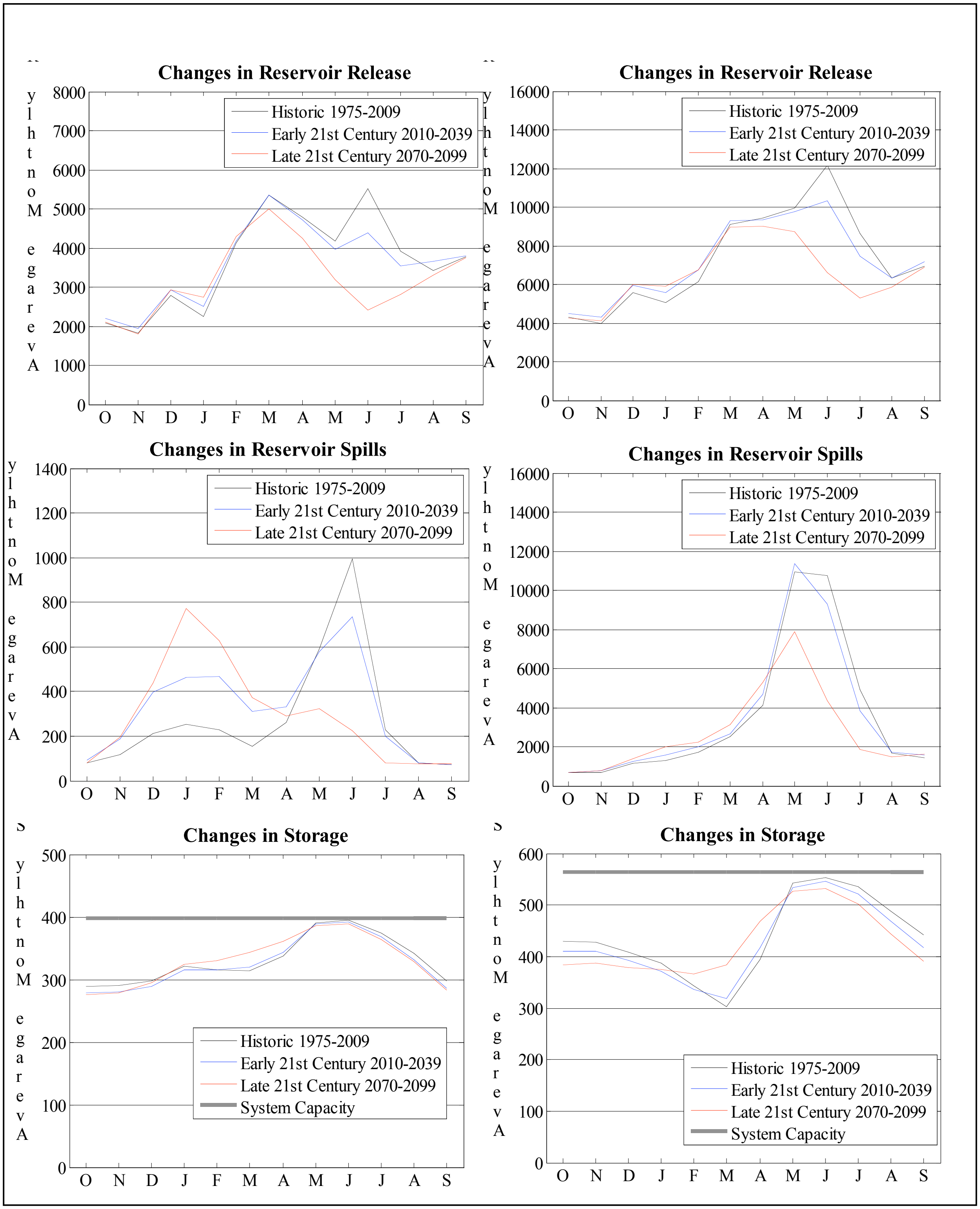

Figure 12. Summary of UARP and Big Creek system's simulated operations under three different time periods

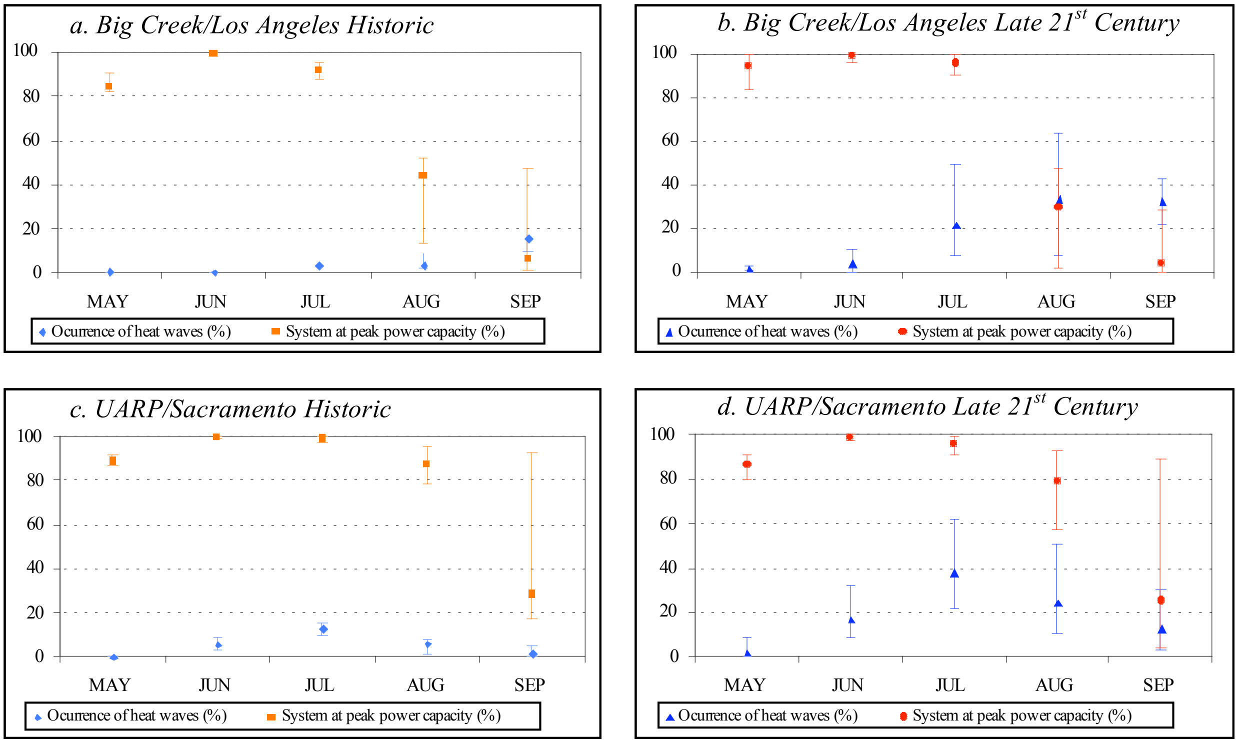

Figure 13. Comparison between occurrence of heat waves and system at peak capacity

One of the benefits of the methodology presented in this paper is that the model can be used to assess the impacts that a changing climate variability could have on system operations. Considering this notion of changing climate variability, we note how the climate scenarios evolve over time in their representation of future conditions. For example, if we take the GFDLA2 climate change projection, the previous realization of this model showed a large and sustained reduction in inflows by the end of the twenty-first century. That persistent drought or "mega drought" as it was called in Purkey et al. (2008) does not have the same magnitude in this new realization of the same scenario. This can be seen by looking at Figure 14, which compares the time series of annual inflows with the end of June total system storage. By looking at the output from the "old" GFDLA2 scenario we clearly see the effects of this extended drought, which meant for the UARP system not only a reduction in energy generation but also a reduction in the ability to meet peak demands during the summer months (a more critical result according to the hydropower systems' operators).

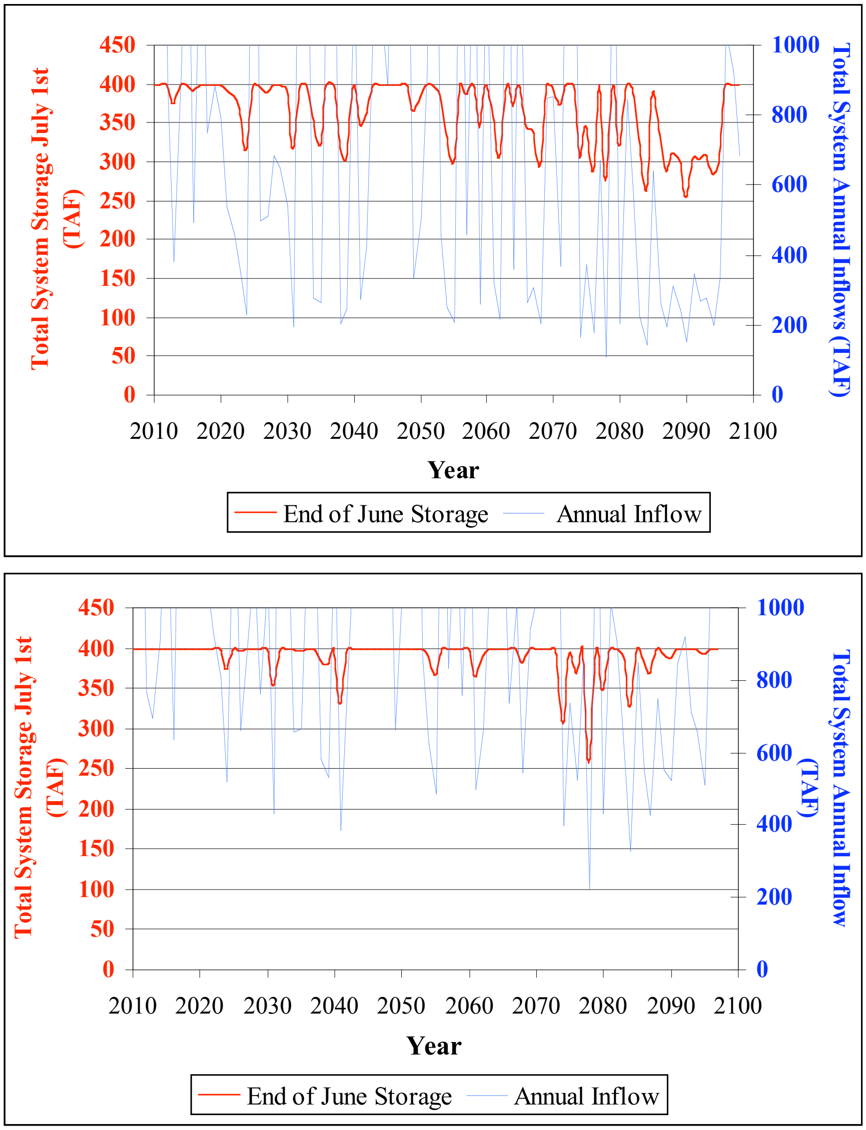

Figure 14. Comparison between annual inflow and end of June storage for the "old" GFDLA2 scenario (Vicuña et al. 2006) (top panel) and "new" GFDLA2 scenario (present paper) (bottom panel). Note: Inflows are capped in the figure at the 1,000 TAF level.

Another interesting feature that can be studied with this model are the conditions affecting systems downstream of the UARP and Big Creek systems. Releases downstream of the UARP system become the inflows for Folsom Reservoir, one of the key components of the Central Valley Project. Folsom Reservoir has a low storage capacity compared to its inflow conditions. Therefore, one of the potential impacts that climate change could have on this system's operations are the occurrence of floods that could affect the city of Sacramento, located downstream of the reservoir. A similar (but less critical) situation occurs with the Big Creek system because downstream of it is Millerton Dam—another important piece of the CVP system that supplies water to agricultural users in the Southern San Joaquin Valley.

Table 8 presents different percentiles of daily outflow from the UARP system for the different climate change scenarios considered in this study. Although median (and even the 99th percentile) daily outflows are reduced for most of the scenarios in the future, which is consistent with a general reduction in runoff associated with the projected climatological conditions, maximum flows over the thirty-year period are consistently increased for all scenarios. This increment is dramatic in some cases, and on the average for all scenarios it implies an increase on the order of 75%, which could lead to potential flooding in the city of Sacramento.

Table 8. Comparison of different levels of daily outflow from the UARP system under historical and late twenty-first century time periods

		Scenario											
		CNRMCM3-A2	GFDL CM21-A2	NCAR PCM1-A2	MIROC32MED-A2	MPIECHAM5-A2	NCARCCSM3-A2	CNRMCM3-B1	GFDL CM21-B1	NCAR PCM1-B1	MIROC32MED-B1	MPIECHAM5-B1	NCARCCSM3-B1
Median Flow (m^3/s)	Historic	26	29	29	29	28	28	29	29	29	28	27	28
	Late 21st	24	20	26	20	26	27	25	23	25	27	25	22
99th Percentile Flow (m^3/s)	Historic	165	198	174	167	164	167	153	172	153	150	161	170
	Late 21st	152	142	137	133	151	184	145	142	145	194	144	191
Max Flow (m^3/s)	Historic	941	2,244	759	1,338	1,222	1,434	873	1,919	873	2,065	1,060	1,211
	Late 21st	2,892	3,078	1,468	2,118	2,194	2,178	2,401	2,352	2,401	3,236	1,661	1,923

5.0 Conclusions

This paper describes the results of our project to estimate the impacts of climate change on two high-elevation hydropower systems in California: SMUD's Upper American River Project (UARP) and SCE's Big Creek System.

Both systems would experience a reduction in runoff and an earlier timing of runoff associated with a reduction in precipitation levels and an increase in temperature levels. However, there are some crucial differences in hydrological impacts between the two systems. Precipitation reduction is projected to be greater in Southern California, and hence the reduction in annual runoff is greater in the Big Creek System than in the UARP system. On the other hand, due to difference in the elevation of the systems, the projections show that the change in the hydrograph pattern is larger in the UARP than in the Big Creek system.

Associated with these projected changes in hydrologic conditions we can see that in both systems and considering the average results for future scenarios there should be a reduction in both energy generation and associated revenues. The UARP system shows a larger impact than the Big Creek system for a given change in annual runoff, due to the larger change in the hydrograph pattern.

Finally, it should be recognized that although these systems could experience these impacts in terms of energy generation the results show that they should still be able to supply peak power demand during the spring and early summer warm days in both Northern and Southern California. However, unless some of operating policies are modified, they could have difficulties meeting an increased power demand in late summer associated with an increase in the occurrence of heat waves.

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7.0 Glossary

A2 — A future emissions scenario with relatively high greenhouse gas emissions as detailed in the *Special Report on Emissions Scenarios* by the Intergovernmental Panel on Climate Change

B1 — A future emissions scenario with relatively low greenhouse gas emissions as detailed in the *Special Report on Emissions Scenarios* by the Intergovernmental Panel on Climate

	Change
BCSD	bias-correction and spatial disaggregation
CALVIN	California-wide economic-engineering optimization model for water supply and environmental purposes developed at the University of California
CNRM	Centre National de Recherches Météorologiques
CVP	Central Valley Project
FERC	Federal Energy Regulatory Commission
GCM	General circulation model
GFDL	A GCM developed by the Geophysical Fluid Dynamics Laboratory and the National Oceanic and Atmospheric Administration
GWh	gigawatt-hour
km	kilometer
LP	Linear programming
m^3/s	cubic meters per second
mill m^3	million cubic meters
MPIE	Max-Planck Institut für Eisenforschung
MW	megawatt
NCAR	National Center for Atmospheric Research
PCM	Parallel Climate Model, a GCM developed by the National Center for Atmospheric Research
PG&E	Pacific Gas and Electric
SCE	Southern California Edison
SMUD	Sacramento Municipal Utility District
SRES	*Special Report on Emissions Scenarios* by the Intergovernmental Panel on Climate Change
TAF	Thousand (1,000) acre-feet, a unit of volume
UARP	Upper American River Project of SMUD
USGS	United States Geological Survey
VIC	Variable Infiltration Capacity model, a macroscale hydrologic model developed at the University of Washington that solves full water and energy balances

Appendix A

LP for On-Off Peak Price Configuration

Appendix A. LP for on-off peak price configuration

For a given month *m* and year *t*, the linear programming model that is solved is the following:

$$\underset{\substack{\mathrm{Rel}_{on,i}^{d_{ini}^{j}}\ldots\mathrm{Rel}_{on,i}^{d_{last}^{j}} \\ \mathrm{Rel}_{off,i}^{d_{ini}^{j}}\ldots\mathrm{Rel}_{off,i}^{d_{last}^{j}} \\ \mathrm{Rel}_{on,i}^{m=j+1}\ldots\mathrm{Rel}_{on,i}^{m=j+12} \\ \mathrm{Rel}_{off,i}^{m=j+1}\ldots\mathrm{Rel}_{off,i}^{m=j+12}}}{Max} \left(\sum_{d=d_{ini}^{j}}^{d=d_{last}^{j}} \sum_{i=1}^{nres} Energy_{on,i}^{d} * c_{on}^{d} + \sum_{d=d_{ini}^{j}}^{d=d_{last}^{j}} \sum_{i=1}^{nres} Energy_{off,i}^{d} * c_{off}^{d} + \sum_{m=j+1}^{m=j+12} \sum_{i=1}^{nres} Energy_{on,i}^{m} * c_{on}^{m} + \sum_{m=j+1}^{m=j+12} \sum_{i=1}^{nres} Energy_{off,i}^{m} * c_{off}^{m} \right) \quad (1)$$

Subject to:

Mass Balance: (for *i*=1..*nres;* for *n*=number of days + number of months)

$$\mathrm{Res}_i^n + \mathrm{I}_i^n + \mathrm{Sp}_{\hat{i}}^n + \mathrm{Rel}_{\hat{i}}^{n,on} + \mathrm{Rel}_{\hat{i}}^{n,off} - \mathrm{Sp}_i^n - \mathrm{Rel}_i^{n.on} - \mathrm{Rel}_i^{n,off} = \mathrm{Res}_i^{n+1}$$

Energy Generation:

$$Power_{on(off),i}^{d(m)} = \min\left[\mathrm{Relrate}_{on(off),i}^{d(m)} * H_i * 9.8 * eff_i, MaxPower_i\right]$$, with Relrate in m^3/seg

$$Energy_{on(off),i}^{d(m)} = f_{on(off),i}^{d(m)} * 24 * Power_{on(off),i}^{d(m)}$$

System capacities:

$$0 \le \mathrm{Res}_i^n \le \mathrm{CapRes}_i$$

$$0 \le \mathrm{Relrate}_{on(off),i}^n \le \mathrm{CapRel}_i$$

$$0 \le \mathrm{Spill}_i^n \le \mathrm{CapSpill}_i$$

Minimum Streamflow Requirements (spills represent flow through the river after the reservoir)

$$\mathrm{SpillMin}_i^n \le \mathrm{Spill}_i^n$$

Where,

j	=	Actual months in simulation
$d_{ini}^{j}, d_{last}^{j}$	=	First and last day in month j
I	=	Component of the system (powerhouse/reservoir)
$Nres$	=	Total number of components
$\mathrm{Rel}_{on,i}^{n}$	=	Release through penstock from reservoir i in period n during peak hours
$\mathrm{Rel}_{off,i}^{n}$	=	Release through penstock from reservoir i in period n during off peak hours
$Energy_{on(off),i}^{d(m)}$	=	Energy generation in day d or month m in component i during peak or off peak hours
$c_{on}^{d}, c_{off}^{d}, c_{on}^{m}, c_{off}^{m}$	=	On and off energy prices at daily and monthly level
Res_{i}^{n}	=	Is reservoir i storage in period n with a maximum of $\mathrm{Cap\,Res}_i$
I_{i}^{n}	=	Inflow to reservoir i, in period n
$\mathrm{Rel}_{i}^{n,on}, \mathrm{Rel}_{i}^{n,off}$	=	Releases on and off peak from above reservoir i, in period n
Sp_{i}^{n}	=	Spills from reservoir i, in period n
$f_{on,i}^{d}, f_{off,i}^{d}, f_{on,i}^{m}, f_{off,i}^{m}$	=	Fraction of time (hours in a day or hours in a month) that the system is operated at on and off peak

Appendix B

LP for Piecewise Linearization Price Configuration

Appendix B. LP for piecewise linearization price configuration

For a given month m and year t, the linear programming model that is solved is the following:

$$\underset{\substack{x_{i,g}^{d_{ini}^j} \ldots x_{i,g}^{d_{last}^j} \\ x_{i,g}^{m=j+1} \ldots x_{i,g}^{m=j+12}}}{Max} \left(\sum_{d=d_{ini}^j}^{d=d_{last}^j} \sum_{i=1}^{nres} \left(MW_i * \frac{h}{d} * \sum_{g=1}^{g=5} p_g x_{i,g}^d \right) + \sum_{m=j+1}^{m=j+12} \sum_{i=1}^{nres} \left(MW_i * \frac{h}{m} * \sum_{g=1}^{g=5} p_g x_{i,g}^m \right) \right)$$

Subject to:

Percent time running through turbines: (for i=1..*nres;* for n=number of days + number of months)

$$\mathrm{X}_i^n = \sum_{g=1}^{g=5} x_{i,g}^n$$

Flow estimation: (for i=1..*nres;* for n=number of days + number of months)

$$\mathrm{Rel}_i^n = \mathrm{CapRel}_i * \frac{h}{n} * \mathrm{X}_i^n$$

Mass Balance: (for i=1..*nres;* for n=number of days + number of months)

$$\mathrm{Res}_i^n + \mathrm{I}_i^n + \mathrm{Sp}_{\hat{i}}^n + \mathrm{Rel}_{\hat{i}}^n - \mathrm{Sp}_i^n - \mathrm{Rel}_i^n = \mathrm{Res}_i^{n+1}$$

Power:

$$MW_i = \min\left[\mathrm{CapRel}_i * H_i * 9.8 * eff_i, MaxPower_i\right]$$, with Relrate in m^3/seg

System capacities:

$$0 \le \mathrm{Res}_i^n \le \mathrm{CapRes}_i$$

$$0 \le \mathrm{Spill}_i^n \le \mathrm{CapSpill}_i$$

Minimum Streamflow Requirements (spills represent flow through the river after the reservoir)

$$\mathrm{SpillMin}_i^n \le \mathrm{Spill}_i^n$$

Piecewise segments constraints

$$0 < x_{i,g}^n < x_{g,\max}^n$$

Where new notation corresponds to,

$x_{i,g}^n$ = Percent time running a given turbine i is running in time period n under a given segment g in the hourly energy price distribution

$x^{n}_{g,\max}$ = Maximum percent of hours for a given segment (g) in the hourly energy price distribution

MW_i = Maximum power for a given powerhouse

$\frac{h}{d}, \frac{h}{m}$ = Number of hours in a given time period (day or month)

p_g = Slope of a given segment of the piecewise energy price distribution

Rel^{n}_{i} = Release through penstock from reservoir i in period n

Appendix C

LP for Piecewise Linearization Price Configuration and Storage Value

Appendix C. LP for piecewise linearization price configuration and storage value

For a given month *m* and year *t*, the linear programming model that is solved is the following:

$$\underset{\substack{x_{i,g}^{d_{ini}^j} \dots x_{i,g}^{d_{last}^j} \\ x_{i,g}^{m=j+1} \dots x_{i,g}^{m=j+12}}}{Max} \left(\begin{array}{c} \sum_{d=d_{ini}^j}^{d=d_{last}^j} \sum_{i=1}^{nres} \left(MW_i * \frac{h}{d} * \sum_{g=1}^{g=5} p_g x_{i,g}^d \right) + \sum_{m=j+1}^{m=j+12} \sum_{i=1}^{nres} \left(MW_i * \frac{h}{m} * \sum_{g=1}^{g=5} p_g x_{i,g}^m \right) + \\ \sum_{d=d_{ini}^j}^{d=d_{last}^j} \sum_{i=1}^{nres} \left(\mathrm{Res}_i^d * VS_i^d \right) + \sum_{m=j+1}^{m=j+12} \sum_{i=1}^{nres} \left(\mathrm{Res}_i^m * VS_i^m \right) \end{array} \right)$$

Subject to same constraints as before

Where new notation corresponds to,

VS_i^n	=	Value given to storage in month *n* and reservoir *i* (it becomes a calibration parameter)

Appendix D

Different Methodologies to Create Future Hydrologic Scenarios

Appendix D. Different methodologies to create future hydrologic scenarios

Perturbation ratio approach (Vicuña et al. 2006; Vicuña et al. 2008):

Future stream flow is derived from multiplying Historical stream flow by a perturbation ratio. This perturbation ratio is derived considering the runoff output from VIC for a given climate change scenario and a combination of grids that best describes monthly pattern of Historical runoff in the given point in the system. The equation that describes this approach with a monthly perturbation ratio is shown below.

$$\mathrm{I}_i^{CC,n} = \frac{\overline{\mathrm{R}}_{gi,CC}^{2070\text{-}2090,m}}{\overline{\mathrm{R}}_{gi,CC}^{1970\text{-}1990,m}} * \mathrm{I}_i^n$$

Where,

I_i^n , $\mathrm{I}_i^{CC,n}$	=	Historical and climate change stream flow respectively for inflow point i in month n and climate change scenario CC
$\overline{\mathrm{R}}_{gi,CC}^{2070\text{-}2090,m}$ $\overline{\mathrm{R}}_{gi,CC}^{1970\text{-}1990,m}$	=	Average runoff in month m for years 2070–2090 and 1970–1990 respectively under climate change scenario CC for a combination of VIC grids (gi) that best represent runoff conditions in inflow point i

Direct approach (Approach used in this study):

Future stream flow in this case is derived directly from the daily runoff projected by VIC. The approach requires first estimating the best mapping function (weights) between Historical stream flow and Historical runoff as predicted by VIC. This mapping function consists of a set of weights and scaling factors derived considering runoff for a set of VIC grids located within the boundaries of system watershed. The weights minimize the difference between the percent monthly stream flow at a given location in the system (i.e., inflow to a given reservoir) and the weighted average monthly runoff as projected in the set of VIC grids. Using this "optimized" weights, a scaling factor is used to estimate the conversion between the grid-based runoff and the actual stream flow associated with a given inflow point and its associated drainage area. The weights and scaling factors are used later to derive daily hydrologic inflow conditions for the different climate change scenarios. All these steps are presented in the following equations.

$$Diff_{i,CC} = \min_{\{w_{i,CC}\}} \left(I\%_i^m - \sum_{gi} w_{gi} * R\%_{gi,CC}^m \right)^2$$

$$F_{i,CC} = \frac{\sum_{m=1:12} \sum_{gi} w_{gi} * \overline{R}_{gi,CC}^{m}}{\sum_{m=1:12} S_i^m} \quad \overline{\mathrm{I}}_i^{m} = f\left(\overline{\mathrm{R}}_{gi,CC}^{m}\right)$$

$$\mathrm{I}_i^{CC,d} = f\left(\mathrm{R}_{gi,CC}^{d}, w_{i,CC}, F_{i,CC}\right)$$

Where new notation introduced corresponds to,

w_{gi}	=	Weight associated with VIC grid *gi*
$\overline{\mathrm{I}}_i^{m}$, $I\%_i^m$	=	Historical average monthly stream flow (and average percent monthly flow) for inflow point *i*
$R\%_{gi,CC}^{m}$	=	Historical monthly percent runoff for VIC grid *gi* under climate change scenario *CC*
$\mathrm{I}_i^{CC,d}$, $\mathrm{R}_{gi,CC}^{d}$	=	Daily stream flow and daily runoff in future day d under climate change scenario *CC*