

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

DRAFT

A Report From:
California Climate Change Center

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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.

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- Renewable Energy Technologies
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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.

Table of Contents

Executive Summary	6
1.0 Introduction	7
2.0 Methodological Approach	9
2.1 Simulation of historic operations.....	9
2.2 Development of future climate change scenarios	11
3.0 Case Studies	13
3.1 Upper American River Project.....	13
3.2 SCE's Big Creek System	Error
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4.0 Results.....	16
4.1 Historic operations results and analysis of changes introduced.....	16
4.2 Climate change results	21
5.0 Conclusions	32
6.0 References	34
Glossary	36

Executive Summary

We present results of our work to estimate the impacts of climate change on two high elevation hydropower systems in California: the Upper America River Projected (UARP) operated by Sacramento Municipal Utilities District (SMUD) in Northern California and the Big Creek system operated by Southern California Edison (SCE) in Southern California. The study builds on previous work modeling the UARP system. The model presented here shows improvements on that model that represent a better simulation of historic 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 UARP 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 UARP 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 historic 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 impacts that could happen 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 (Madani et al., 2007, 2008; Tanaka et al., 2007; Vicuna et al., 2006, 2008). Hydropower constitutes around 15% of in state energy generation in California (Aspen Environment and M-Cubed, 2005) with a greater value associated with its use predominantly during on-peak periods. 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 Utilities 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 EPA and California Energy Commission (http://www.climatechange.ca.gov/climate_action_team/reports/index.html). The results of that report including the study developed by this research group on the impacts on the UARP system were published on a special issue of the Climatic Change journal (Cayan et al. 2008).

In our current research presented in this report, recognizing some of the limitations of our previous work (Vicuna, et al. 2006, 2008), we have introduced three major modifications to the model developed to optimized and simulate the historic 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 have 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 of the actual projections of an 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 under both historic 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 allows obtaining a more complete picture of the effects of climate change on high elevation hydropower in California.

The report is organized as follows:

1. First the methodology used to estimate the impacts of climate change on the operations of a high elevation hydropower system is introduced
2. Then we introduce our two cases studies, the UARP and the SCE Big Creek systems.
3. Then we present the analysis of the results associated with the historic and climate change scenarios selected for this work.
4. We finish with 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 includes a calibration first of a simulation model of the historic operations and then the study of the effects of climate change using the calibrated simulation model.

2.1 Simulation of historic operations

To simulate the operations of the high elevation hydropower system we have 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 detail operations of the system (reservoir storage, reservoir release through turbines and through 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 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. 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 Callso prices specific for each month. Five segments are considered in the linearization for each month. This is considered an improvement of our previous work which included only a single on 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 PX data (Appendix A shows the comparison of the LP model formulations under the two energy price structure). 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).

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 took into account 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 historic operations. Appendix B shows briefly the changes introduced in the objective function by this new structure.

The optimization routine is performed over a moving horizon of 12 months, similar to the approach considered by Hooper et al., (1991). Limiting the model horizon to 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 by the end of the timestep period. The inclusion as part of the objective function of the remaining 11-months 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 month. This “moving horizon” optimization approach is a compromise between a reasonable amount of hydrologic information and simplicity in the objective function formulation and will be subject to more analysis in future developments of the model.

The model developed in Vicuna 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. In order 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 modeled developed in Vicuna et al. (2008):

1. We included a smaller time horizon for the daily optimization module that better reflects uncertainties associated with flood events. The idea was to reduce that foresight to a more reasonable level (5 days instead of a whole month).
2. We reduced the amount of foresight the model is assuming in determine 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 2-3 months of inflows 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 are 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 as is available for the LP model at any point in time. If we look at the LP model formulations (Appendix C) we have that 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 consequent segment of 5 days that would be used in the daily window of optimization. The second change is with the mass balance equation were now instead of using the perfect foresight inflow (I_t^n) we use now 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)

$$I_i^n = I_i^{t,m,d} \text{ (actual inflow conditions for year } t, \text{ month } m \text{ and day } d)$$

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

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

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 historic 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 system of reservoir. In future studies this 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, which releases becomes the inflow conditions 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 flooding conditions affecting the operations of this reservoir that could affect the city of Sacramento.
- Spills and other reservoir operating variables: A detailed model as this one based on principles such as water balance but considering detail 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.

In order to represent changes in future hydrologic variability we are using instead of a perturbation ratio approach (Vicuna et al., 2007, Vicuna et al., 2008) direct time series of hydrologic conditions as projected by the 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 not relies on the perturbation ratios is beneficial because the effects of changes in the inter annual variability of climatologic and hydrological variables could be studied with such approach (Purkey et al., 2008).

For the specific impacts associated with hydropower operations using a direct hydrology approach allows the exploration of the transient and progressive effects of climate change. This is critical to answer questions about when should operations (or forecasting schemes) be altered base on the already visible effects on the hydrologic conditions.

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

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

The focus of this project is the study the operations under historic 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. One of them is the Upper American River Project (UARP) located in the Upper American and Rubicon basins (headwaters at 9,900 ft (\approx 3,000 m)) and operated by Sacramento Municipal Utilities District (SMUD). The second case study is the Big Creek system located in the upper San Joaquin basin (headwaters at 14,000 ft (\approx 4,200 m)) and operated by Southern California Edison (SCE). A map showing the location of both systems is presented in Figure 1.

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 km) of power tunnels/penstocks. The system is located above Central Valley Project (CVP)'s Folsom Dam. Annual runoff to the UARP system is roughly 1,000 TAF. The project is currently in a FERC (Federal Energy Regulatory Commission) relicensing stage, and thus sufficient data were publicly available to conduct the case study. The Project is composed of seven separate developments (a summary with major characteristics of these developments is shown in Table 1).

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 thousand acre-ft (TAF) distributed within 6 major reservoirs located within the upper San Joaquin river watersheds. The system is located above Pacific Gas&Electric (PGE)'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. The Project is composed of nine separate developments (a summary with major characteristics of these developments is shown in Table 2).

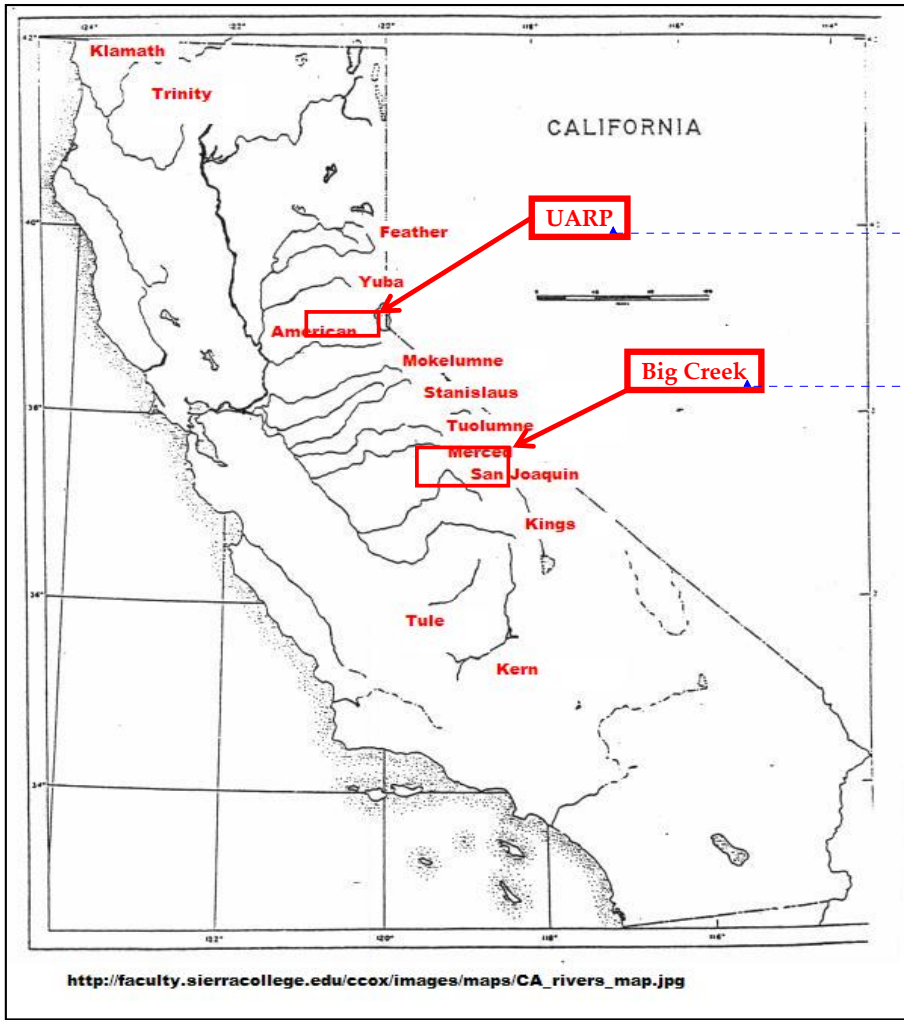
As can be seen from the data presented in both Tables 1 and 2 and above, the UARP and Big Creek possess those typical characteristics of what have been normally dominated a high elevation hydropower system (Aspen Environment and M-Cubed, 2005). Elevation of the components in both cases are above 1,000 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.

Table 1. UARP system components included in the model

PARAMETER	COMPONENT						
	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. SCE system components included in the model

PARAMETER	COMPONENT								
	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



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Figure 1. Location of UARP and Big Creek systems

4.0 Results

4.1 Historic operations results and analysis of changes introduced

To simulate historic operations of the UARP and Big Creek systems we used as input timeseries 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 1982-2002¹. The inter annual variability of hydrologic conditions in both the UARP and Big Creek systems is shown in Figure 2 showing the similar pattern but different magnitude of annual runoff in both systems.

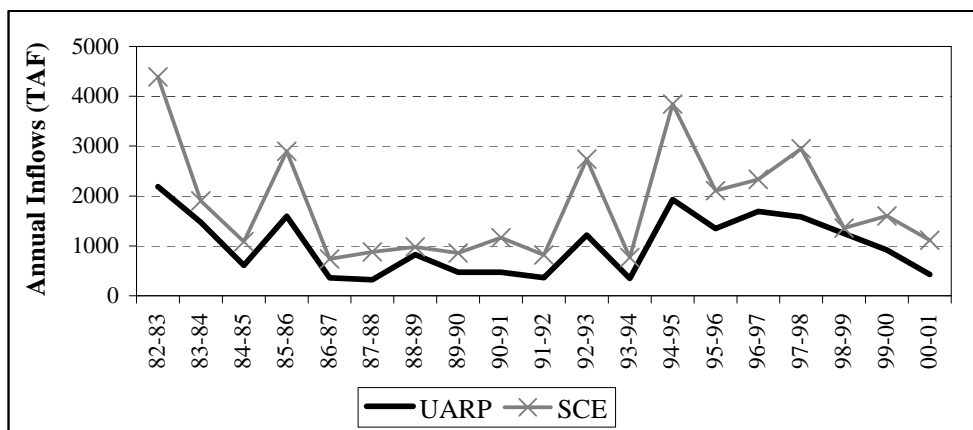


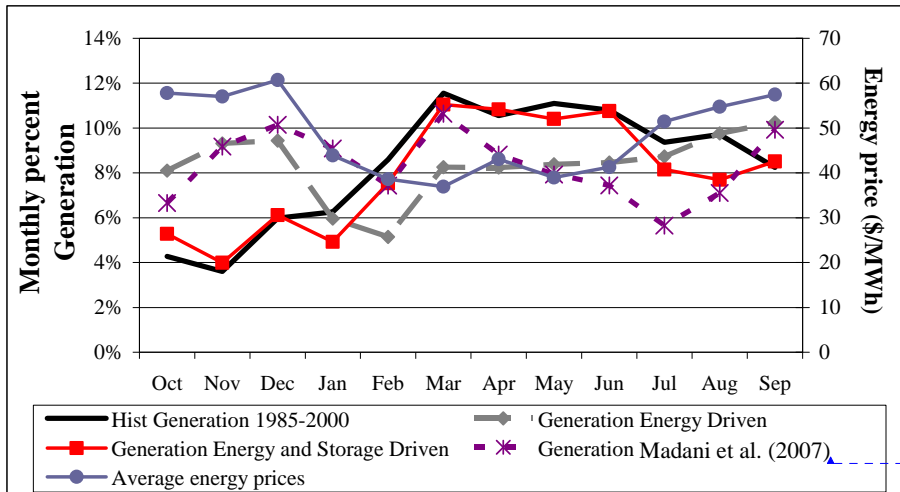
Figure 2. Annual runoff into the UARP and Big Creek systems.

The historic operations for both systems were simulated using the LP optimization routing explained in Section 2 of this report. As explained before we have considered two different objectives to determine these operations. On one case the objective function considers only energy generation revenues (we call this the “energy driven” model) and the other we consider both energy revenues and storage value (we call this the “energy and storage driven” model). Two 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 were we compare the results with historic conditions. Figure 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:

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

¹ These data sets were provided by SMUD and SCE respectively.

In the Figure 3 showing the monthly pattern of generation we have included as well the results in energy patterns from a energy storage model considered in the comparative study presented in Madani et al. (2007) and the monthly average energy prices. In Figures 5, 6 and 7 we show average monthly and annual spills and average monthly end of month storage for all reservoirs respectively comparing the two structures of objective formulations.



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

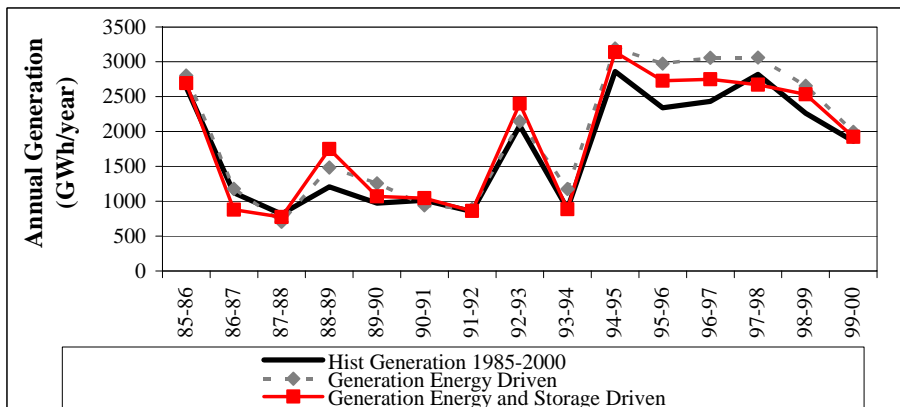


Figure 4. Comparison between historic and modeled annual energy generation in the UARP system

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 both the annual scale (model over predicts generation) and at 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 average energy prices (also shown in the Figure), so it seems that operations are not purely driven by this variable. A system that is driven purely by energy prices and importantly with a fixed head (as we have set it up here for our LP configuration) has little incentive to fill up the reservoirs. So it tries to keep them as empty as possible gaining always from the releases made and the energy being generated. With a close-to-empty reservoir 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 here spills considers all flows not passing through turbines so includes stream flow requirements). With a reduction in spills water passing through turbines is enhanced and so energy generation is higher than at the historic conditions.

Including a value for storage for different months in order to represent objectives other than energy revenues clearly improves the results. By adding this value, reservoir storage increases (compare two scenarios in Figure 7) inducing a relative higher amount of spills (Figures 5 and 6), reducing energy generation (Figure 4) and shifting generation to months without a relative higher energy price (especially spring months). There is still a slight over prediction in generation which is probably due to:

- an under prediction 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)
- an over estimate of the generation capacity of the power plants especially in the generation efficiency.

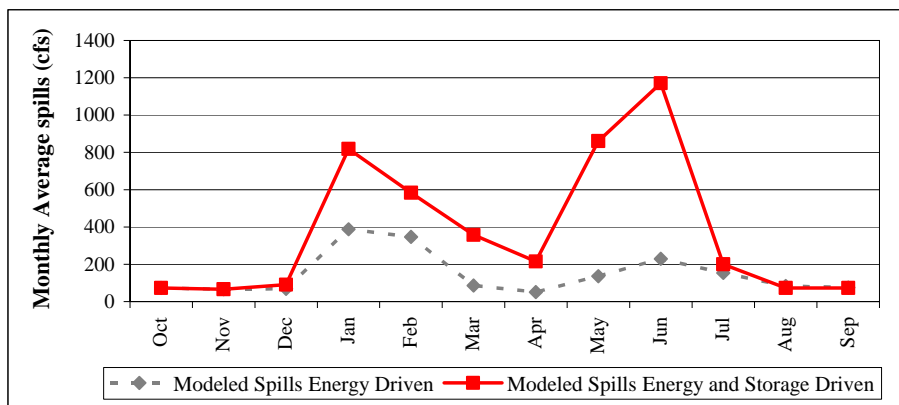


Figure 5. Average monthly spills (TAF) in the UARP system

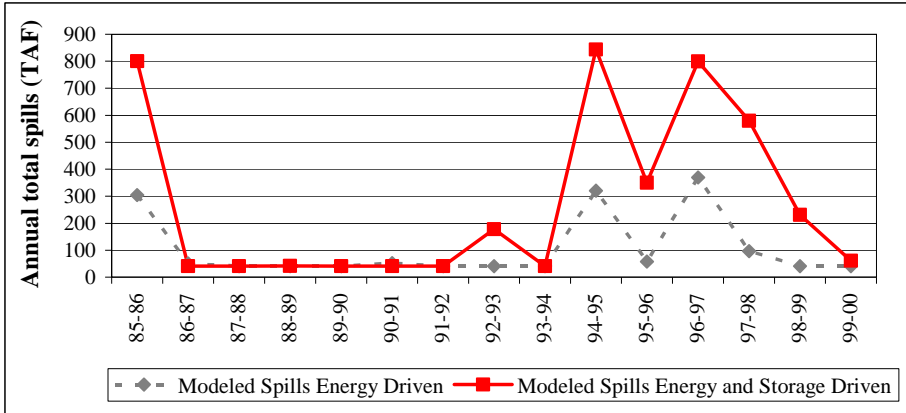


Figure 6. Annual spills (TAF) in the UARP system

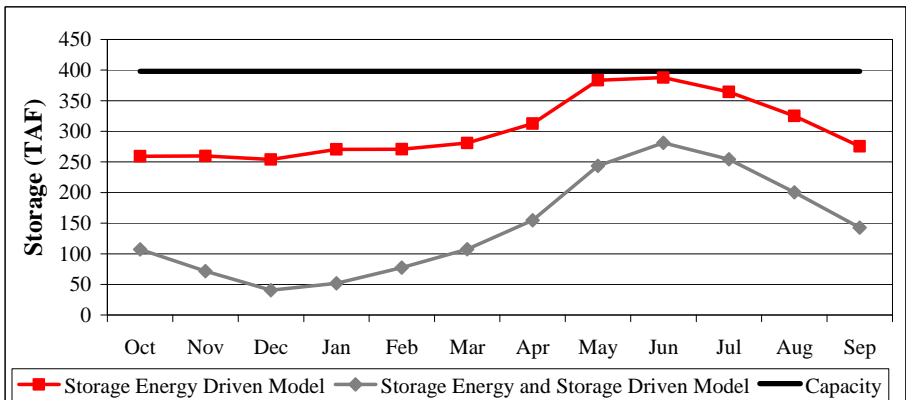


Figure 7. Average end of month storage for the whole system (TAF) in the UARP system

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 greatly with the historic operations of this system as can be seen in Figures 8 and 9. In these Figures we compare monthly average and annual energy generation of the SCE system.

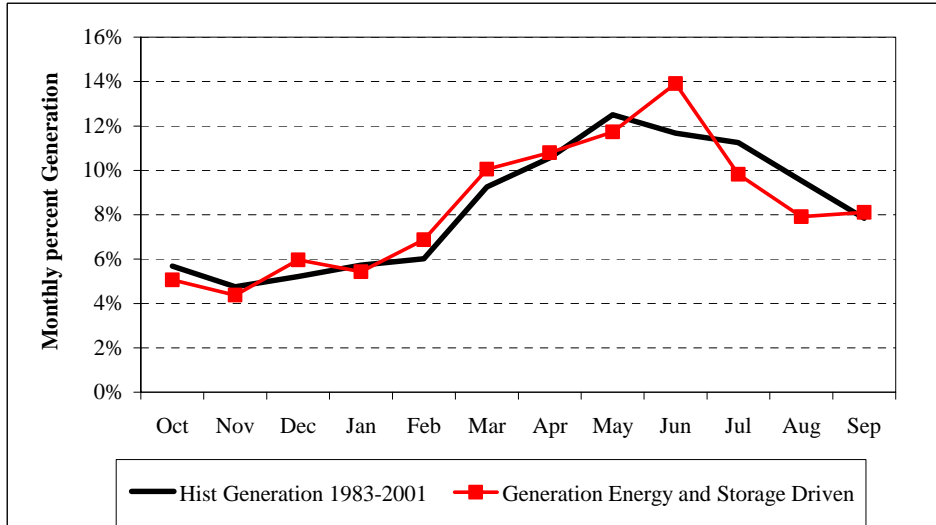


Figure 8. Comparison between historic and modeled monthly percent energy generation in the Big Creek system

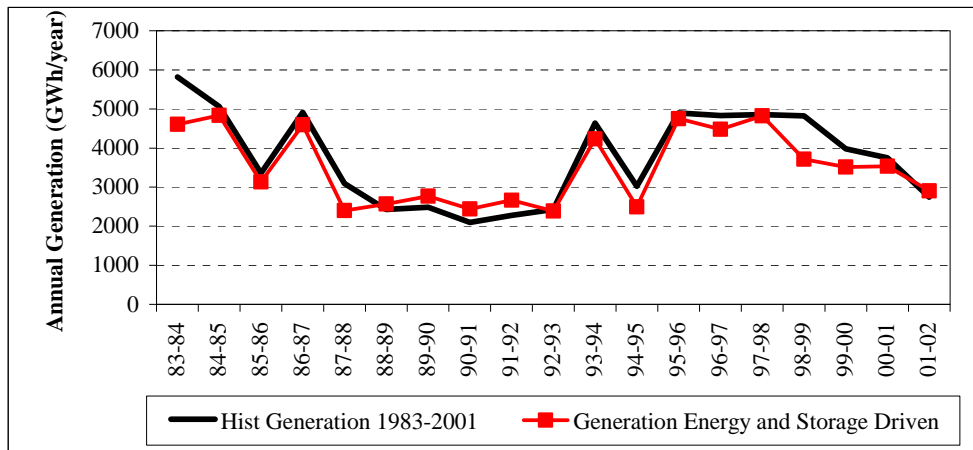


Figure 9. Comparison between historic and modeled annual energy generation in the SCE system

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 (<http://meteora.ucsd.edu/cap/scen08.html>). 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 arrange of scenarios we have chosen to use the BCSD downscaled datasets. All the scenarios used in this work (listed in Table 1) were previously run through the VIC² hydrology model. 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 followed by using the methodology explained in the previous chapter (and in more detail in Appendix D) to develop timeseries of future hydrologic conditions for the two systems for each one of the climate change scenarios.

Table 1. Climate change scenarios used in the analysis

GCM	Emission scenarios ³	
CNRMCM3	B1	A2
GFDL CM21	B1	A2
NCAR PCM1	B1	A2
MIROC32MED	B1	A2
MPIECHAM5	B1	A2
NCARCCSM3	B1	A2

2. 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, and has been successfully applied at resolutions ranging from a fraction of a degree to several degrees latitude by longitude. A description of VIC can be found in Cayan et al. (2006).

3. 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 carbon emissions, while B1 reflects a future with lower CO₂ emissions. These 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 in (ref when available). A description of the hydrologic model VIC can be found in (Nijssen, et al., 1997).

Table 2 summarizes the main characteristics of the scenarios developed by comparing the following metrics for three different periods: Historic (1974-2010) as represented by the climate change scenario; Early 21st century (2011-2040); Mid 21st century (2041-2070); Late 21st century (2071-2100). To simplify the presentation we show the average of the absolute value for the historic period and the different climate scenarios for the different variables. To show the change for later periods we show both the average and range of the relative comparisons for the different scenarios. The results are shown for the hydrology of the UARP and the Big Creek system separately.

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

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

- Consistent with previous works done in California there is clearly uncertainty in terms of the overall amount of water that could be flowing through the system. For both systems we see that average annual inflow is slightly decreasing for the early part of the century for the average conditions for the scenarios' projections; by mid century this reduction in inflows is more obvious and in the case of the UARP system it is projected by almost all scenarios (with just one showing just a slight increase in inflows; by end of the century the uncertainty is still very large (specially for the Big Creek System) and the magnitude of the inflow reduction is even larger when taking the scenarios in average. Another important observation to make with regards to the change in the amount of water flowing through these systems is that the projections show much larger reductions in the Big Creek system than on the UARP system. This is a consistent result with the projected changes in climatic conditions in Northern and Southern California (reference when available)
- In terms of the timing of inflows there is a clear reduction of the snowmelt season runoff consistent with the notion that increasing temperatures modify the timing of streamflow towards earlier in the water year (Vicuna and Dracup, 2007). All the scenarios and for all time periods we see this trend (with the exception of one scenario in the early 21st 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 Figure 10 where we present average monthly runoff for both systems and the four different time period. 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 the results in average we have that historical hydrologic conditions represent that almost 70% of runoff flows during the typical snowmelt season. This number is reduced by more than 20% in average for all scenarios. 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 historic conditions and that number is reduced to slightly above 75% under future (end of century) projections. Interesting to note that that number is still above current conditions for the UARP system.

Considering that there are not significant differences in temperature projections for both regions, this difference in hydrologic pattern can be attributed only to the difference in elevation of both systems (the Southern Sierra Nevada Mountains being higher than the Northern counterparts). This has been a typical result for studies done in California in terms of differences in the sensibility of the two regions for the changes in temperature levels.

- And finally in average all scenarios show an increase 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. It is interesting to note that the Big Creek system has under historic conditions smaller extreme flows during the winter months although 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 difficult their operations during winter months and increase the amount of undesired spills occurring.

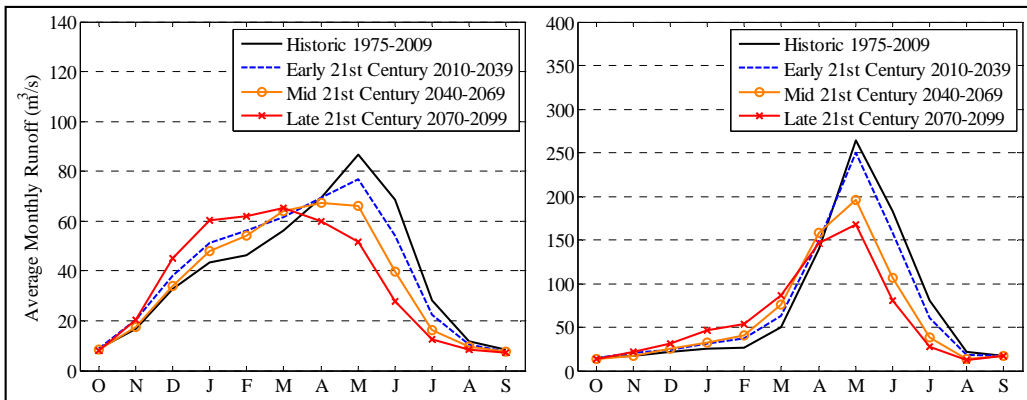


Figure 10. Changes in monthly hydrologic conditions in UARP and Big Creek systems

Table 2. Comparison of hydrologic conditions for different time periods and the two hydropower systems considered in this study (absolute value for historical period and average plus range in percentage change for future periods)

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 runoff 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 have selected the following key variables:

- Annual and Monthly Energy Generation
- Average August system capacity (a measure of the ability of the system to meet peak demands by the end of summer)
- Annual and Monthly Spillage
- Downstream release (to Folsom and Millerton dams)

A Table summarizing the output for all scenarios and all time periods is presented as follows. The format of presentation is similar to the case where we show the projected hydrologic conditions. For each of the variables considered we show first the average value for the historic period and then for each of the future time periods we show the average change (percent change from historic conditions) and the range considering the results from all scenarios.

Table 3. Comparison of different system outputs for different time periods and the two hydropower systems considered in this study (absolute value for historical period and average plus range in percentage change for future periods)

Variable	Period	System	
		UARP 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 3. 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. Similarly to the conclusions derived in Vicuna 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).

To further understand the impacts that changes in the hydrologic conditions have on the operations of these systems we have produced a series of additional figures. First in Figure 11 we compare for all scenarios but just the last time period (late 21st century) the changes (as compared to historic values) in annual system runoff with annual changes in annual energy generation and annual revenues. In the chart we have also included the best fit linear relation for all four data sets with the main properties of these relationships presented in Table 4. The figure shows a series of interesting results. First we corroborate here that there is a clear relation 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 this chart 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. And the sign of the coefficient of this variable clearly shows that as annual runoff is reduced energy generation and revenues are reduced as well.

It is interesting though to note here some subtleties in these asseverations. First we see that 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 as expressed earlier the ability of the system operations to move water throughout the 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 SCE 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).

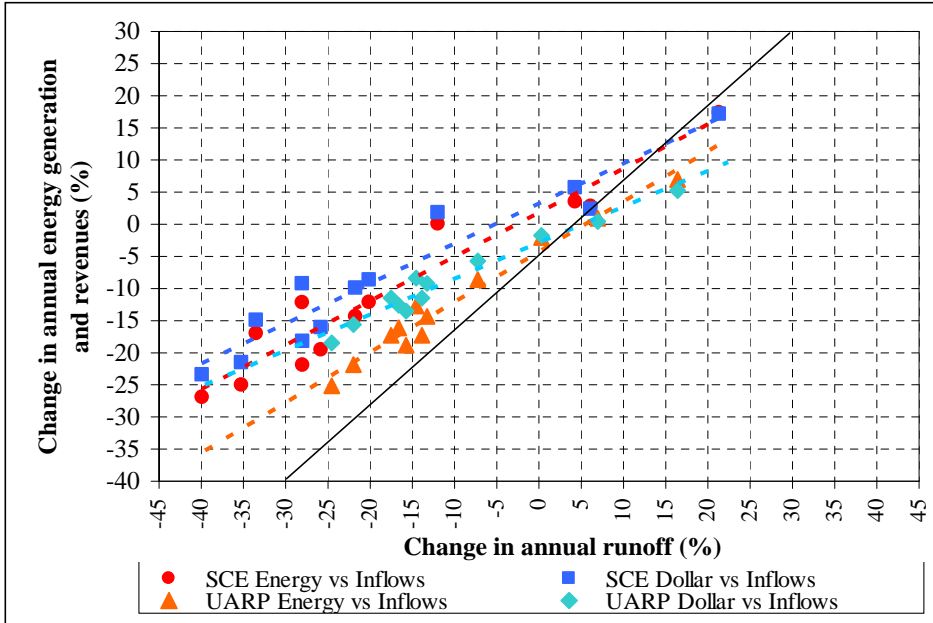


Figure 11. Comparison between changes in hydrologic conditions and UARP and Big Creek systems' outputs

Table 4. 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

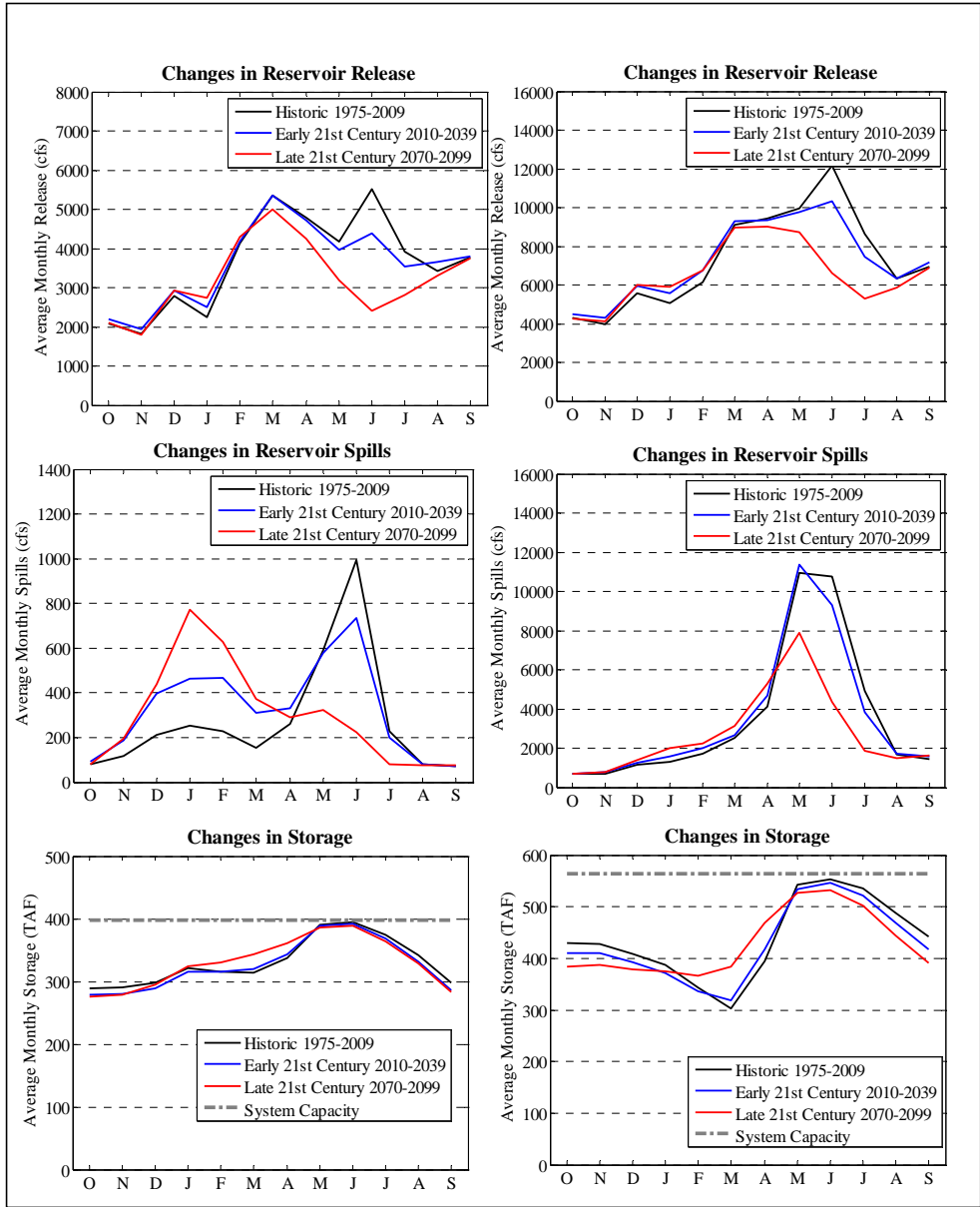


Figure 12. Summary of UARP and Big Creel system's operations under three different time periods

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 (historic, early and late 21st century). The charts presented show 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 historic 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 occurring concentrated during the spring and summer months. This difference is even larger under the climate scenarios especially by the end of the century where the UARP now experiences the most of the occurrence of spills during the winter months but the Big Creel 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 the reason why there is a larger reduction in energy generation and revenues. It also interesting to note now going back to Figure 11 that this change in timing of runoff affects UARP system operations in a way that in the future an increase in runoff has associated a smaller (in a relative sense) increase in revenues. This can be checked by looking that for those scenarios that have an increase in runoff in the UARP system the dots representing the changes in outputs is below the 45° line meaning the change is smaller in a relative sense. 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 4) is larger than the difference existing in the case of the Big Creek system. In the case of the Big Creek system we have that for most scenarios with the exception of the driest one 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 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 their reservoir inflows. Not having flood control rules attached to their management operations allowed these systems to deal very effectively with changing inflow conditions by change the timing reservoirs are being refilled and emptied.

With regards 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 this capacity. The average system power capacity in August is reduced at the most in 0.6%. A reason behind this insensitivity is that it has to be kept in mind that these high elevation systems have a large proportion of their head available fixed (use the gradient in the terrain as 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 highly 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. The effect that this could have on both the UARP and Big Creek systems is shown in Figure 13. In this Figure we present 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 historic 95th percentile, **ref when available**) and the percent time where system power capacity (is above the 99% percent level). This information is presented for four cases: historic and late 21st century for the UARP and Big Creek systems. For each one of these cases we present the analysis for the months from May till September and in each case we show the average for all 12 scenarios but also the range in the conditions. It can be shown in this Figure that both systems operating according to historic objectives (historic energy prices and peak demand) shouldn't have problems supply energy at time with peak demand from May until July. In August and especially in September we see that the Big Creek system would face a situation where the number of days with head 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 we see though that the range of heat waves percentage overlaps the range of peak system capacity. Based on these results we can conclude that these two systems shouldn't have problems meeting peak power demands in the late spring and early summer months even with an increase in power demand associated with increased occurrence of heat waves. However, if there is an increase in heat waves latter in the summer, these two systems (especially the Big Creek system) would have trouble meeting peak demand unless keeping extra water stored in reservoirs and hence reducing even further the amount of energy being generated (due to increased spills).

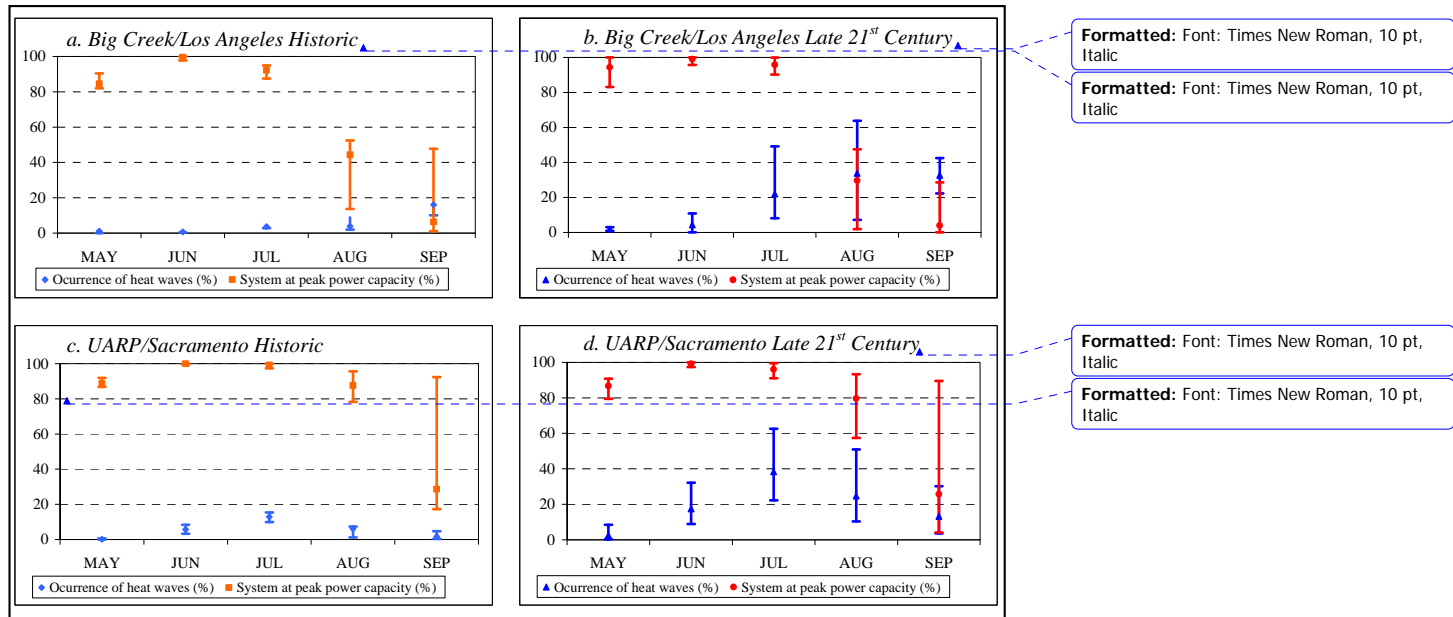


Figure 13. Comparison between occurrence of heat waves and system at peak capacity

One of the benefits of the methodology presented in this work is that the model can be used to assess the impacts that a changing climate variability could have on system operations. By looking at this factor we noted how the climate scenarios evolve over time in their representation of future conditions. For example if we take as an example the GFDLA2 scenario, the previous realization of this model showed a large and sustained reduction in inflows by the end of the 21st century. That persistent drought or “mega drought” as was called in Purkey et al. (2008) doesn’t have the same magnitude in this new realization of the same scenario. This can be seen by looking at Figure 14. In this Figure we compare the timeseries 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).

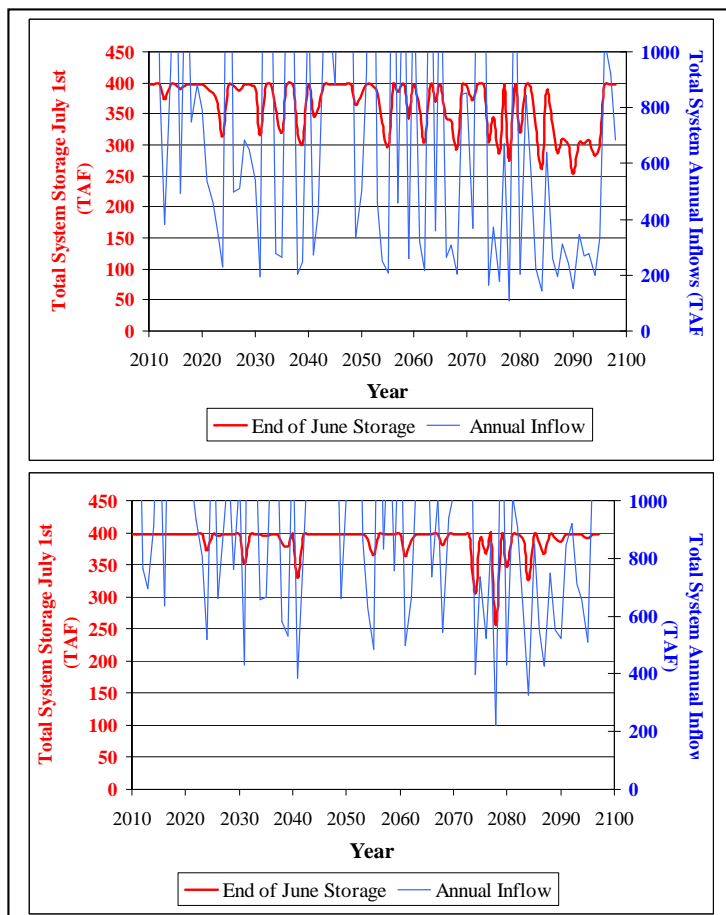


Figure 14. Comparison between annual inflow and End of June Storage for “old” GFDLA2 (top panel) and “new” GFDLA2 (bottom panel). Note: Inflows at capped in the Figure at the 1,000 TAF level just for depicting purposes.

Another interesting feature that can be studied with this model are the conditions affecting systems downstream of UARP and Big Creek systems. Releases downstream of the UARP system become the inflows for the Folsom reservoir, one of the key components of the Central Valley Project. Folsom reservoir has a low storage capacity compared to its inflow conditions. And hence one of the potential impacts that climate change could have on the operations of this system 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 were downstream of it is located Millerton Dam another important piece of the CVP system that supplies with water agricultural users in the Southern San Joaquin Valley. In the next Table we present different percentiles of daily outflow from the UARP system for the different climate change scenarios considered in this study. It can be seen that although median (and even the 99th percentile) daily outflows are reduced for most of the scenarios in the future as consistent with a general reduction in runoff associated with the projected climatological conditions, maximum flows are consistently increased for all scenarios. This increment is dramatic in some cases and in average for all scenarios imply an increase in the order of 75% which could lead to potential flooding issues in the city of Sacramento.

Table 5. Comparison of different levels of dialy outflow from the UARP system under historic and late 21st 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

In this report we describe results of our project to estimate the impacts of climate change on two high elevation hydropower systems in California. The report is organized into three sections. First we introduce our revised methodology to estimate the impacts of climate change on the operations of a high elevation hydropower system. Second, we present our analysis of the UARP and Big Creek systems under historic conditions using the revised model. The benefit of these innovations is apparent in improved simulation of UARP operations. Third we present the impacts of projected climate change hydrology on the operations of both the UARP and Big Creek Systems.

The impacts on the hydrology of both systems have some crucial differences. 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 the reduction in precipitation is projected to be larger in Southern California and hence the reduction in annual runoff is larger in the Big Creek System as compared to the UARP system. On the other hand due to difference in the elevation of both systems the projections show that that change in the hydrograph pattern is larger in the UARP than on the Big Creek system. Associated with these projected changes in hydrologic conditions we can see that in both systems and taking the future scenarios in average there should be a reduction in both energy generation and associated revenues. The UARP system due to the larger change in the hydrograph pattern has a larger impact in these outputs than the Big Creek system for a given change in annual runoff. Finally we see 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 associate with an increase in the occurrence of heat waves.

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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
CALVIN	California-wide economic-engineering optimization model for water supply and environmental purposes developed at the University of California
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
LP	Linear programming
PCM	Parallel Climate Model, a GCM developed by the National Center for Atmospheric Research
SCE	Southern California Edison
SFAR	South Fork of the American River
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

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

$$\begin{array}{l}
 \text{Rel}_{on,i}^{d_{ini}^j} \dots \text{Rel}_{on,i}^{d_{last}^j} \\
 \text{Rel}_{off,i}^{d_{ini}^j} \dots \text{Rel}_{off,i}^{d_{last}^j} \\
 \text{Rel}_{on,i}^{m=j+1} \dots \text{Rel}_{on,i}^{m=j+12} \\
 \text{Rel}_{off,i}^{m=j+1} \dots \text{Rel}_{off,i}^{m=j+12}
 \end{array}
 \left(\sum_{d=d_{ini}^j}^{d=d_{last}^j} \sum_{i=1}^{nres} \text{Energy}_{on,i}^d * c_{on}^d + \sum_{d=d_{ini}^j}^{d=d_{last}^j} \sum_{i=1}^{nres} \text{Energy}_{off,i}^d * c_{off}^d + \sum_{m=j+1}^{m=j+12} \sum_{i=1}^{nres} \text{Energy}_{on,i}^m * c_{on}^m + \sum_{m=j+1}^{m=j+12} \sum_{i=1}^{nres} \text{Energy}_{off,i}^m * c_{off}^m \right) (1)$$

Subject to:

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

$$\text{Res}_i^n + \text{I}_i^n + \text{Sp}_i^n + \text{Rel}_i^{n,on} + \text{Rel}_i^{n,off} - \text{Sp}_i^n - \text{Rel}_i^{n,on} - \text{Rel}_i^{n,off} = \text{Res}_i^{n+1}$$

Energy Generation:

$$\text{Power}_{on(off),i}^{d(m)} = \min \left[\text{Rebrate}_{on(off),i}^{d(m)} * H_i * 9.8 * \text{eff}_i, \text{MaxPower}_i \right], \text{ with Rebrate in } \text{m}^3/\text{seg}$$

$$\text{Energy}_{on(off),i}^{d(m)} = \int_{on(off),i}^{d(m)} * 24 * \text{Power}_{on(off),i}^{d(m)}$$

System capacities:

$$0 \leq \text{Res}_i^n \leq \text{CapRes}_i$$

$$0 \leq \text{Rebrate}_{on(off),i}^n \leq \text{CapRel}_i$$

$$0 \leq \text{Spill}_i^n \leq \text{CapSpill}_i$$

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

$$\text{SpillMin}_i^n \leq \text{Spill}_i^n$$

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
$Rel_{on,i}^n$	=	Release through penstock from reservoir i in period n during peak hours
$Rel_{off,i}^n$	=	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 $CapRes_i$
I_i^n	=	Inflow to reservoir i , in period n
$Rel_i^{n,on}, Rel_i^{n,off}$	=	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

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

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

Subject to:

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

$$X_i^n = \sum_{g=1}^{g=5} x_{i,g}^n$$

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

$$Rel_i^n = CapRel_i * \frac{h}{n} * X_i^n$$

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

$$Res_i^n + I_i^n + Sp_i^n + Rel_i^n - Sp_i^n - Rel_i^n = Res_i^{n+1}$$

Power:

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

System capacities:

$$0 \leq Res_i^n \leq CapRes_i$$

$$0 \leq Spill_i^n \leq CapSpill_i$$

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

$$SpillMin_i^n \leq Spill_i^n$$

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
- $x_{g,\max}^n$ = 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_i^n = Release through penstock from reservoir i in period n

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:

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

Subject to same constraints as before

Where new notation corresponds to,

\bar{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

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

Future stream flow is derived multiplying historic 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 historic runoff in the given point in the system. The equation that describes this approach with a monthly perturbation ratio is shown below.

$$I_i^{CC,n} = \frac{\bar{R}_{gi,CC}^{2070-2090,m}}{\bar{R}_{gi,CC}^{1970-1990,m}} * I_i^n$$

Where,

$I_i^n, I_i^{CC,n}$ = Historic and climate change stream flow respectively for inflow point i in month n and climate change scenario CC

$\bar{R}_{gi,CC}^{2070-2090,m}$ = Average runoff in month m for years 2070-2090 and 1970-1990 respectively under climate change scenario CC for a combination of

$\bar{R}_{gi,CC}^{1970-1990,m}$ 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 historic stream flow and historic runoff as predicted by VIC. This mapping function consist 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. In Figure XX we compare the historic inflows for a particular reservoir of the UARP system and those derived using this approach but using the historic VIC runoff output.

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

$$F_{i,CC} = \frac{\sum_{m=1:12} \sum_{gi} w_{gi}^{\square} * \bar{R}_{gi,CC}^m}{\sum_{m=1:12} S_i^m} \bar{I}_i^m = f(\bar{R}_{gi,CC}^m)$$

$$I_i^{CC,d} = f(R_{gi,CC}^d, w_{i,CC}, F_{i,CC})$$

Where new notation introduced corresponds to,

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