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Climate change impacts on high elevation hydropower generation in California's Sierra Nevada: a case study in the Upper American River

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Abstract Climate change is likely to affect the generation of energy from California's high-elevation hydropower systems. To investigate these impacts, this study formulates a linear programming model of an 11-reservoir hydroelectric system operated by the Sacramento Municipal Utility District in the Upper American River basin. Four sets of hydrologic scenarios are developed using the Variable Infiltration Capacity model combined with climatic output from two general circulation models under two greenhouse-gas emissions scenarios. Power generation and revenues fall under two of the four climate change scenarios, as a consequence of drier hydrologic conditions. Energy generation is primarily limited by annual volume of streamflow, and is affected more than revenues, reflecting the ability of the system to store water when energy prices are low for use when prices are high (July through September). Power generation and revenues increase for two of the scenarios, which predict wetter hydrologic conditions. In this case, power generation increases more than revenues indicating that the system is using most of its available capacity under current hydrologic conditions. Hydroelectric systems located in basins with hydrograph centroids occuring close to summer months (July through September) are likely to be affected by the changes in hydrologic timing associated with climate change (e.g., earlier snowmelts and streamflows) if the systems lack sufficient storage capacity. High Sierra hydroelectric systems with sufficiently large storage capacity should not be affected by climate-induced changes in hydrologic timing.

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1 Introduction

High-elevation basins in the Sierra Nevada Mountains are responsible for almost 50% of all hydroelectricity generated in California (Aspen Environmental and M-Cubed 2005), due largely to their head potential and snow storage. These systems vary in terms of managing utility, storage capacity, conveyance capacity and altitude. Those systems with very little storage capacity are unable to store flows in excess of their turbine capacities. Systems with more significant storage can accumulate excess water for later release through the turbines. Two important objectives in the operation of a hydropower system are (1) to generate during periods when demand is high and energy is more valuable, and (2) to minimize unnecessary spilling (water lost without electricity generation). In California, peak energy demand occurs during hot summer afternoon hours, when the demand for air conditioning is high, rather than in the winter. Spills are most recurrent during the reservoir refilling periods (spring month) but can also occur in winter months.

The most consistent result of previous studies on the effects of climate change on California hydrology is that the timing of the center of mass of the annual hydrograph shift to earlier in the year during the next century (Vicuna and Dracup 2007). This shift is associated with an increase in temperature that leads to (1) a higher proportion of precipitation falling as rain (as compared to snow) and (2) earlier spring snowmelt. Those two changes are likely to affect the operations of high elevation hydropower reservoirs with low storage capacity. They could induce a timing mismatch between energy generation and energy demand. Additionally, higher inflows in winter could increase spillage and reduce overall energy generation.

Previous studies on the impacts of climate change on hydropower systems in California have all focused on hydropower systems located at low elevations (less than 1,000 ft). Yao and Georgakakos (2001) developed an integrated forecast-decision system to assess the sensitivity of reservoir performance to various forecast-management schemes under historical and future climate scenarios (based on projections from the Canadian Center for Climate Modeling and Analysis model). They assessed daily operations for hydropower generation and flood control of Folsom Dam under various combinations of inflow forecast predictions, decision rules, and climate scenarios and used as case study. The study demonstrated that “(1) reliable inflow forecasts and adaptive decision systems can substantially benefit reservoir performance and (2) dynamic operational procedures can be effective climate change coping strategies”. VanRheenen et al. (2004) reached different conclusions studying the effects of different climate change scenarios based on projections of NCAR’s PCM general circulation model (GCM). They considered the effects of climate change on flood control, hydropower production, agricultural and municipal diversions, and instream flows for fish. VanRheenen et al. (2004) showed that even with the incorporation of mitigation strategies, such as changing the flood control rule curves, achieving and maintaining status quo system performance (including hydropower production) would not be possible under the climate change scenarios. Tanaka et al. (2006) used CALVIN, a large-scale economic–engineering optimization model of California’s water supply, to study the effects of a range of climate change scenarios on the long-term performance and management of California’s water system, including hydropower generation. They found that hydropower production from the major water supply reservoirs would be mostly affected by the amount of water available, with wetter scenarios showing an increase in generation and revenues proportional to the change in streamflow and drier scenarios displaying the opposite pattern.

This paper studies the potential effects of climate change-induced hydrological changes on high elevation hydropower generation in California with special emphasis on the "warming" forms of climate change effects. For a case study, this research focused on the Upper American River Project (UARP), a Sacramento Municipal Utility District (SMUD) hydroelectric system. The UARP is located in El Dorado and Sacramento counties, on the west slope of the Sierra Nevada Mountain Range. The UARP system was constructed between 1957 and 1985. It includes 11 reservoirs that can impound over 425,000 acre-feet (AF) of water, eight powerhouses that can generate up to 688 megawatts (MW) of power, and about 28 miles of power tunnels/penstocks. It is fed by the Rubicon River, Silver Creek, and the South Fork American River drainages. A map of the general location and schematic of the UARP system appears in Fig. 1.

2 Methodology

Our approach to studying the effects of climate change on the UARP system consists of the following steps:

– Constructing time series of daily and monthly historical unimpaired streamflows into the system using USGS streamflow data where available, and extensions of the same by correlation analysis.
– Perturbing daily and monthly hydrologic data using climate change signals associated with four GCMs/emission scenarios.
– Simulating system operation with a linear programming model under both historical and climate change conditions.

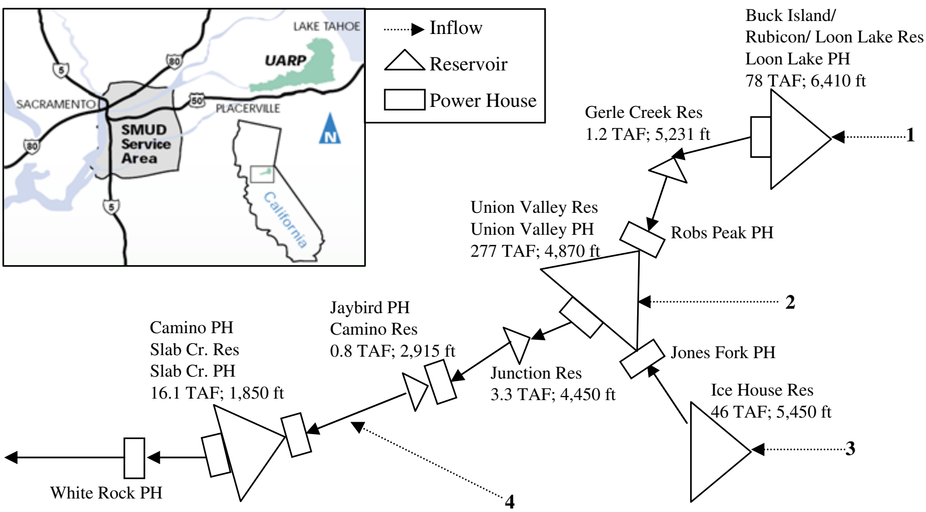


Fig. 1 Schematic of Upper American River Projects (Source of general location map: SMUD 2001)

2.1 Development of historical daily streamflow time series

Four major rivers/creeks feed into the UARP: the Rubicon River, Silver Creek, South Fork Silver Creek, and South Fork American River. These tributaries are denoted in Fig. 1 by numbers 1 to 4, respectively. The period 1928 through 1949 was selected to represent historical conditions in the system. As this was before the installation of the reservoir system, the data represents unimpaired streamflow. A record of daily inflows to the system for this period was constructed using data available from USGS gauge stations and correlation analysis from nearby gauging stations. Figure 2 shows monthly average (from 1928 to 1949) streamflow conditions for the aggregated inflows to the UARP system (values are given in thousand acre-feet (TAF) per month, with one AF equal to 1,233 m^3). The same graph shows the average of the 10th and 90th percentiles of daily flows within each month. The streamflow pattern shown includes two peak natural streamflow conditions, a smaller peak occurring in winter (storms) and a larger peak occurring in spring (snowmelt streamflow). Flows drop significantly in July.

2.2 Development of perturbation ratios

To determine the hydrologic conditions under the different climate change scenarios we use output from the Variable Infiltration Capacity (VIC) model. VIC 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 in latitude and longitude. Further description of VIC can be found in Liang et al. (1994) and Nijssen et al. (1997). Four sets of daily and monthly runoff predictions from the VIC model are used to develop perturbation ratios. These four data series are hydrologic representations of runoff at a particular VIC grid location based on climate output from the NCAR PCM and GFDL CM2 climate models run under the greenhouse gas emission scenarios SRES A2 and SRES B1 We refer to these four scenarios as PCMA2, PCMB1, GFDLA2, and GFDLB1 (see Cayan et al. (2006) for a description of the scenarios chosen in the analysis). From the ten gridcells that cover UARP's headwater basins, we choose that gridcell that most closely represented the historic hydrologic pattern

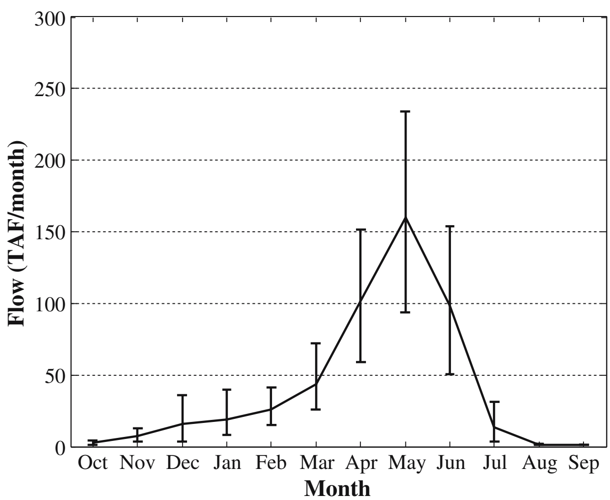


Fig. 2 Unimpaired (pre-dam) inflows to the UARP system under Historical (1929–1948) conditions. Shown are mean and 10th and 90th percentiles

of runoff conditions in the UARP system. The gridcell chosen is located at Lat/Long: 39.0625/120.1875. Figure 3 shows a comparison between historical (as recorded) and historical (as predicted under the climate change scenarios) median monthly runoff (as percentages of annual flows) for the chosen gridcell.

Unimpaired natural runoff representing the period 1960–1990 as predicted by the VIC model run under the different climate change scenarios (not actual historical streamflow) is compared with runoff predictions for 2070–2099. The perturbation ratio is a simple ratio of average runoff predicted by a GCM for different eras for a given time period (eg.$Q_{2070-99}/Q_{1960-90}$, where Q is average July streamflow) (see Vicuna et al. 2007; Miller et al. 2003; Brekke et al. 2004). This can then be used to perturb a historical data series as an alternative to using pure hydrologic model output at the spatial and temporal resolution needed for the analysis. The development of monthly perturbation ratios was a straightforward procedure that consisted of determining runoff averages for each month in both the historical and future climate change predictions. Figure 4 shows the monthly perturbation ratios for the four climate change scenarios. The general trend from these perturbation ratios is a decline in spring and summer streamflows and an increase in streamflows in winter (perturbation ratios lower and larger than 1, respectively). This translates into earlier timing for the peak and centroid of inflows. To develop the daily perturbation ratios for these scenarios, each month is divided into equal-sized sets of wet, normal, and dry days. Averages are then taken of all wet January days, all normal January days, and so on, for both the historical and climate change-predicted periods. This yields three series of monthly perturbation ratios for each climate change scenario, allowing both average and extreme hydrograph changes to be tracked. Figure 5a and b shows the modified streamflow conditions after application of the daily perturbation ratios. Figure 5a shows changes in the mean conditions while Fig. 5b shows changes in monthly coefficient of variation. The climate change conditions display

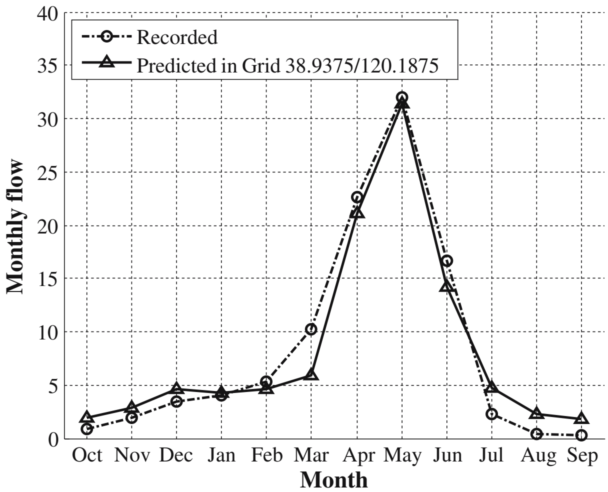


Fig. 3 Comparison between median monthly streamflow (as percent of annual streamflow) as recorded in all gages located in the UARP system and median monthly runoff (again as percent of annual runoff) as predicted by all climate change scenarios at VIC Grid 38.9375/120.1875. (It was determined that pattern of flows for different locations within the system were very similar so the analysis was done considering the all locations together. Since the flows are normalized in each case there is no problem in considering them altogether. A similar argument was used to consider together the monthly pattern for all climate scenarios at a given grid cell)

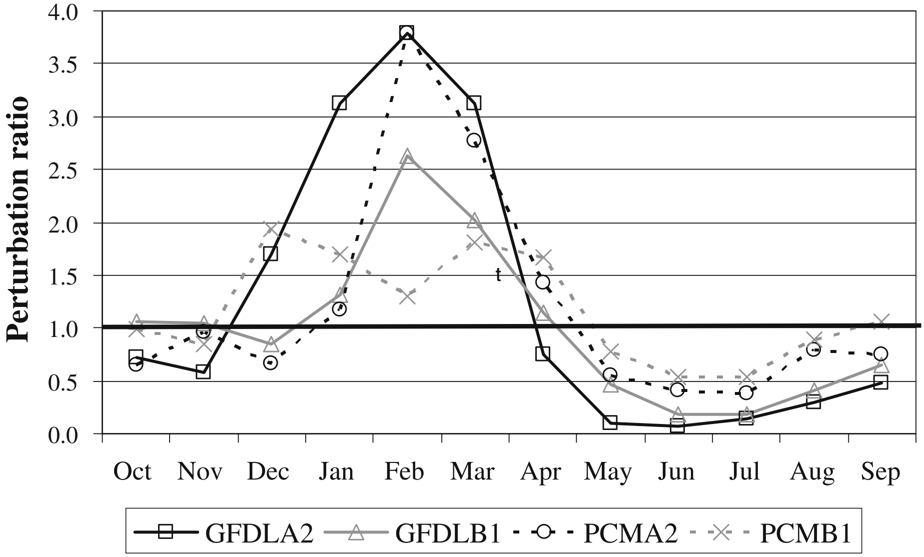


Fig. 4 Monthly perturbation ratios (based on 2070–2099 climate change conditions)

the expected earlier timing of inflows and, interestingly, a more pronounced hump of high flow conditions in winter months (with an increased mean and coefficient of variation). The most extreme case is GFDLA2, in which the timing of the peak streamflow shifts from May to February.

2.3 Linear programming model

A multi-step linear programming (LP) optimization model was developed to represent operations of the aggregated SMUD hydroelectric system in the Upper American River. The objective of the optimization is to maximize energy generation revenues, restricted to operational constraints (e.g. minimum instream requirements), and physical constraints, such as turbine or reservoir capacity. Following formulations used by Grygier and Stedinger (1985) and Trezos and Yeh (1987) the model distinguishes between the generation of on- and off-peak energy, sold respectively at on and off-peak prices. To determine the on- and off-peak pricing we perform a frequency analysis of hourly Northern California Power Exchange (PX) energy market clearing prices for the period from April of 1998 until April of 1999 (data available from http://www.ucei.berkeley.edu/). System operations of the UARP are based on a variety of factors in addition to electricity generation, including operational releases for peaking, real-time load following, and river management (SMUD 2001). This study's simplified model of UARP operations uses energy prices as a proxy for all these factors. In calculating energy generation, it is assumed that the head remains constant throughout the optimization. This allowed for UARP optimization to be represented by a LP problem. The assumption is reasonable in this case, because the maximum variability of reservoir water elevation is much smaller than the head drop used to generate hydropower.

The optimization is performed over a moving horizon of 12 months, similar to the approach considered by Hooper et al. (1991). Within these 12 months the model has complete knowledge of hydrologic conditions (perfect foresight) at different temporal

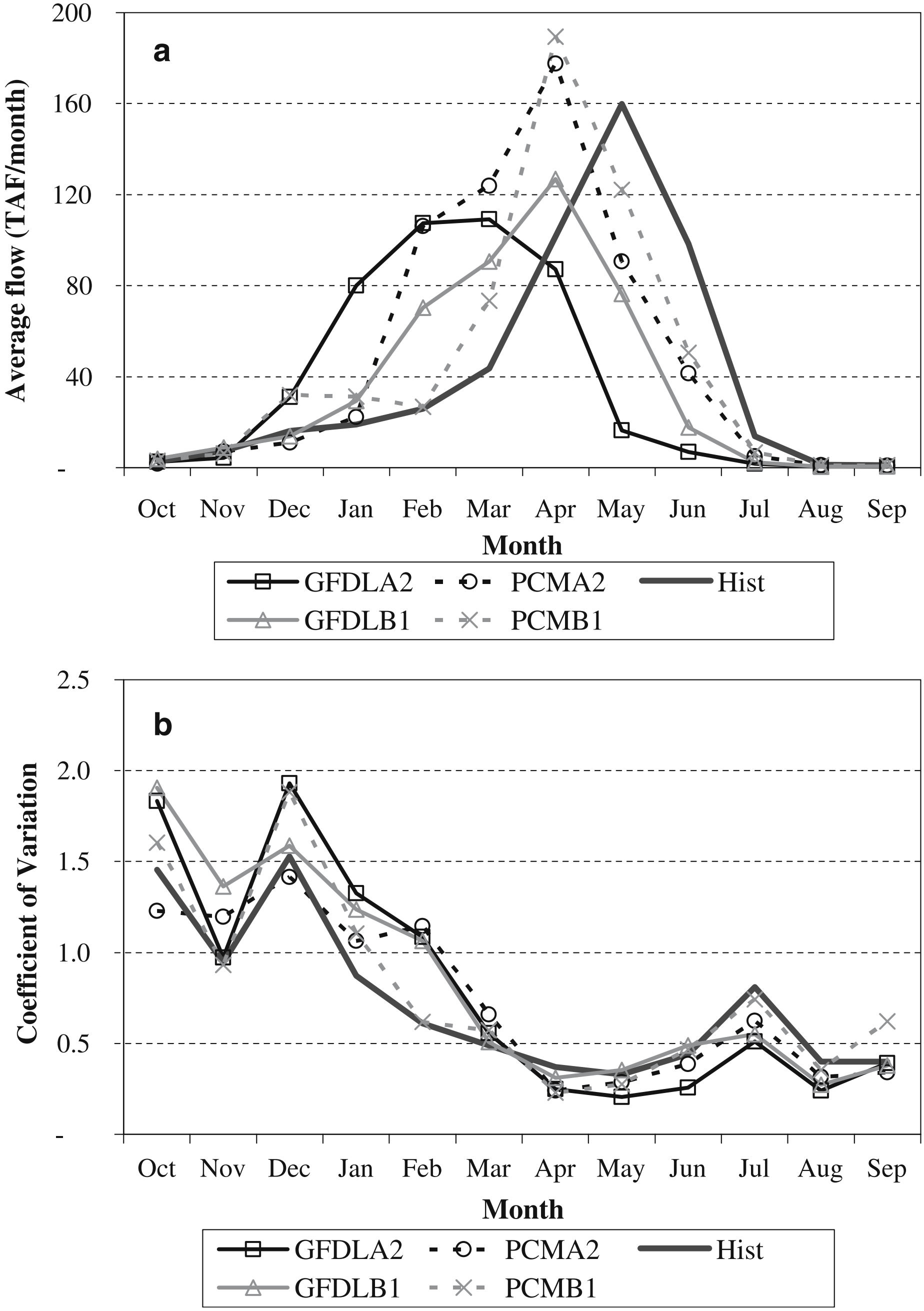
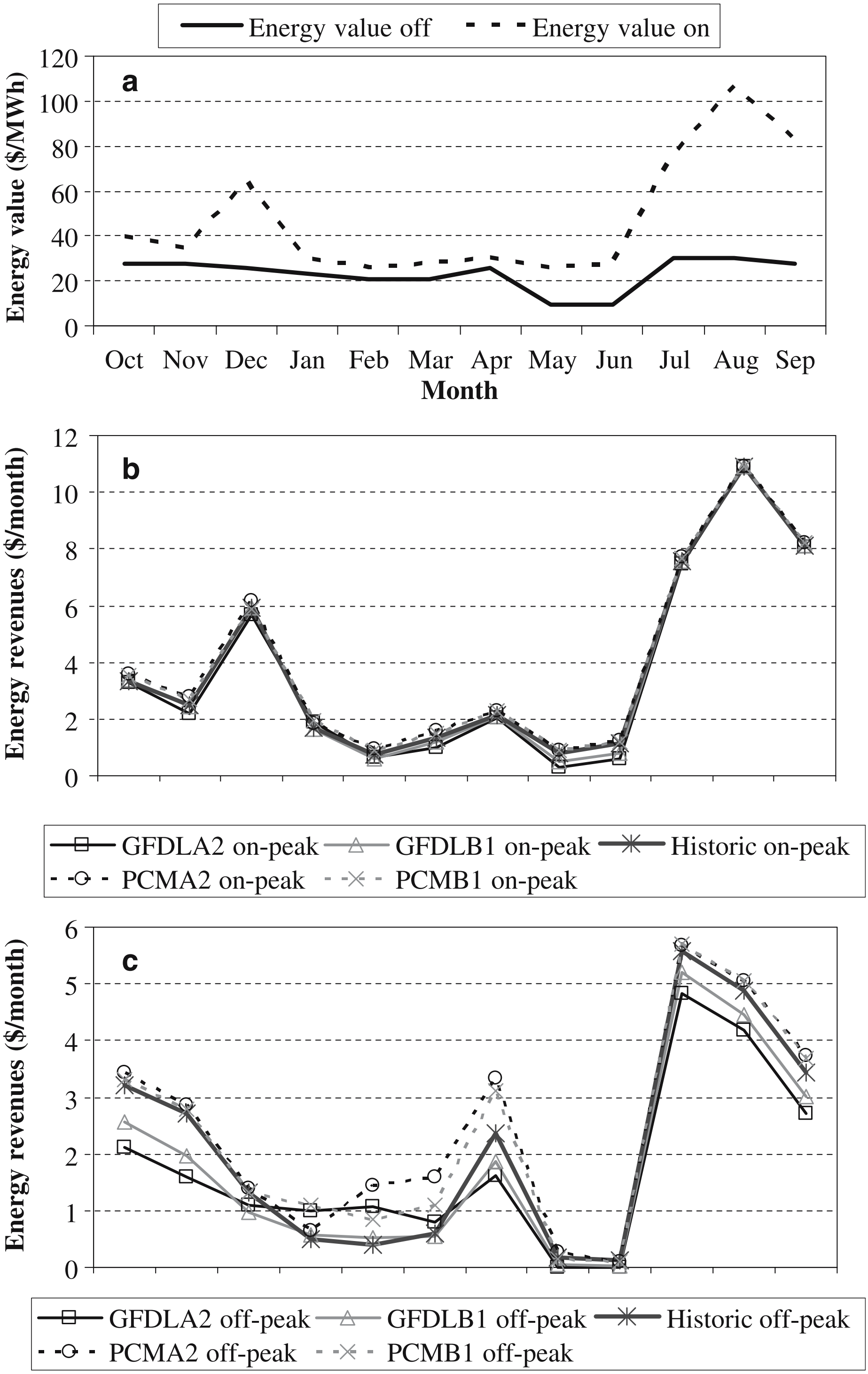


Fig. 5 Changes in unimpaired inflows to the UARP system under Climate Change scenarios. **a** Changes in mean. **b** Changes in coefficient of variation


Energy value off
Energy value on
a
Energy value ($/MWh)
120
100
80
60
40
20
0
Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep
Month
b
Energy revenues ($/month)
12
10
8
6
4
2
0
GFDLA2 on-peak
GFDLB1 on-peak
Historic on-peak
PCMA2 on-peak
PCMB1 on-peak
c
Energy revenues ($/month)
6
5
4
3
2
1
0
GFDLA2 off-peak
GFDLB1 off-peak
Historic off-peak
PCMA2 off-peak
PCMB1 off-peak

◀ **Fig. 6** Monthly energy revenues: comparison of scenarios. **a** Monthly pattern of on and off-peak energy prices. **b** Monthly on-peak energy revenues. **c** Monthly on-peak energy revenues

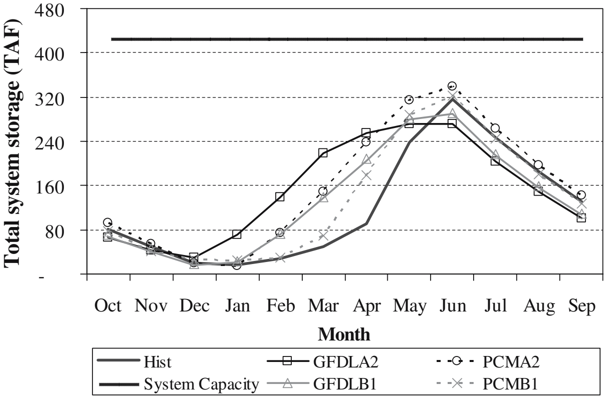
resolutions. The first of these months is optimized at a daily time step and the remaining 11 months are modeled at monthly time steps. The use of a daily time step within the first month allows the assessment of single flood events, which is crucial to the analysis of system operation with regard to undesired spillage. If the horizon of optimization is restricted to include only this first month of operations the LP model, in order to maximize profits, completely drains 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. Only the output from the first month is retained; the results of the 11-month model results are discarded and the next time-step performs daily optimization of the "second" 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.

3 Results

The LP model is run under historical and climate change hydrologic conditions. Figures 6, 7, 8, 9 and Table 1 summarize the most relevant results. Figure 6 shows end-of-month storage for the system as a whole under all scenarios. Figure 7 shows the monthly pattern of on- and off-peak energy revenues and the corresponding pattern of monthly energy prices. Figure 8 shows the monthly pattern of spills for the system as a whole. Table 1 compares the annual output for three metrics of interest: hydropower generation, energy revenues and average spillage. Finally, Fig. 9 presents the data from Table 1 in a format that facilitates comparison. In this graph the *x*-axis represents the percentage of annual inflows (as compared to historical conditions) for a given scenario while the *y*-axis represents the corresponding change in each metric (also compared to historical conditions).

The historical scenario demonstrates that the model replicates expected patterns of operations for this system: generating electricity in the more valuable summer months,

Fig. 7 Monthly system storage: comparison of scenarios



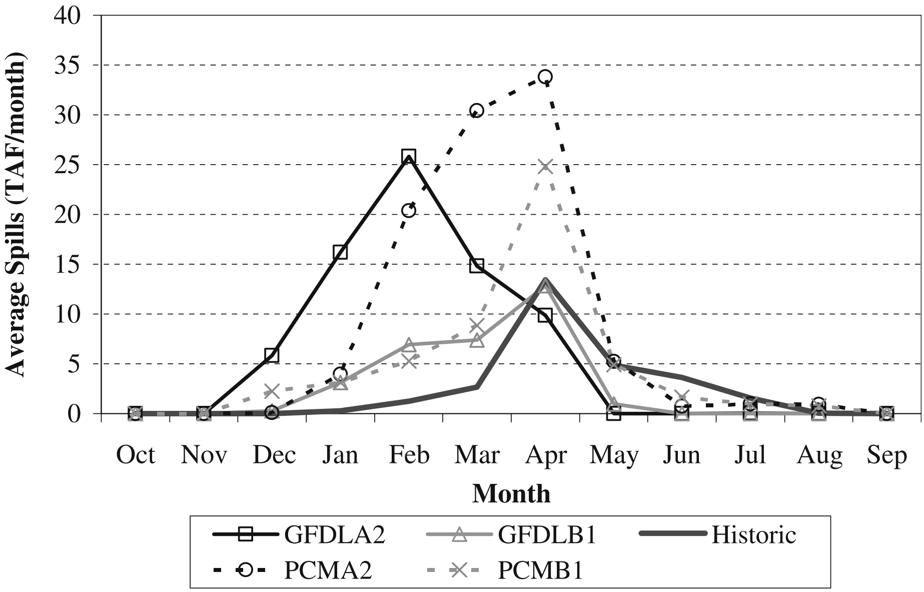


Fig. 8 Monthly average spills: comparison of scenarios

refilling reservoirs by July 1 and leaving sufficient storage in the reservoirs on October 1 to ensure minimum summer generation during subsequent hydrologic years (see Figs. 6 and 7).

When comparing the climate change scenarios we find two (GFDLA2 and GFDLB1) that show a reduction of annual revenues (generation) by about 10% of historical values, while the other two (PCMA2 and PCMB1) show an increase in annual revenues (generation) of a similar order of magnitude (see Table 1). Changes in annual inflow conditions (see Fig. 9) generally drive the changes in total hydropower generation (the same results were found in Tanaka et al. 2006). However, the changes in annual inflows are normally larger in absolute value than the changes in generation revenues. For the drier scenarios, the system is able to continue moving water releases (in time) to more valuable months, reducing the economic effect that a drop in annual inflow might otherwise have. However, in the wetter scenario the increase of inflows exceeds the increase of revenue, since there is little unused system storage under current hydrologic conditions to store extra water for more valuable months. Hence there are limited increments to the benefits of a wetter scenario. The ability of a system to store and move water within a year has long been studied, with Hazen (1914) providing a rich seminal discussion in the topic. When one examines the monthly pattern of energy revenues (Fig. 7) for the whole system of seven powerhouses, all scenarios show a pattern of generation similar to the monthly pattern of the energy value, with maximum generation during the summer months and minimum during spring and winter. It is clear that on-peak generation is a priority that can be met under all hydrologic conditions, while off-peak generation depends on the water available in the system.

The UARP system, as modeled with our partial perfect foresight model, showed great flexibility in accommodating changes in the timing of inflows by changing the timing of reservoirs refills and draw down cycles (Fig. 3). However, the system was not able to eliminate the damaging effects of changes in timing and inflow variability associated with the climate change scenarios. This becomes clear if one compares the results for GFDLB1 and GFDLA2; although more water is available under GFDLA2, the drop in energy

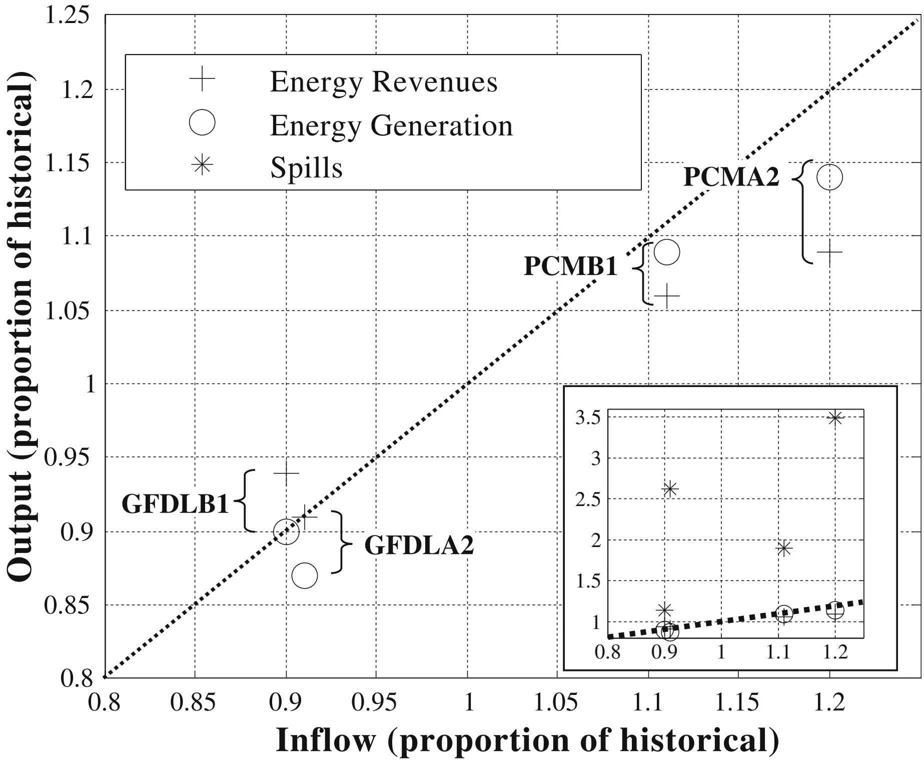


Fig. 9 Annual output (as compared to historical conditions) for different climate change scenarios as a function of the percentage of annual inflow

generation revenues is larger than the drop under GFDLB1 (see Table 1 and Fig. 9). The reasons for this are evident when comparing the patterns of streamflow under each scenario that created a larger spillage under GFDLA2 (see Figs. 5 and 8). However, the differences are smaller than might be expected considering GFDLA2's relatively inconvenient hydrograph. It has significantly larger shifts in the timing of inflows and a greater shift in timing and magnitude of high inflows than GFDLB1 (see Fig. 5). Another piece of evidence of the damaging effects associated with climate change is that all scenarios shared an increase in

Table 1 Comparison of different outputs from the system for all hydrologic scenarios

		Generation						
		Million Dollar/year			GWh/year			
	Inflow (TAF/year)	On	Off	Total	On	Off	Total	Average Spills (TAF/year)
Historical	491	46	25	71	823	928	1,751	28
GFDLA2	448	44	21	65	756	770	1,527	73
GFDLB1	442	45	22	67	784	786	1,570	32
PCMA2	589	48	30	78	880	1,117	1,998	97
PCMB1	544	48	28	76	865	1,050	1,915	53

the occurrence of spills, compared to the historical conditions (see Figs. 8 and 9). In the next section we explore other factors that play a crucial role in determining the impacts associated with climate change on high elevation hydropower systems.

3.1 Sensitivity analysis

The operation of a hydropower generation system depends not only on the hydrologic conditions of the basin but also on characteristics of the infrastructure such as reservoir, powerhouse, and conveyance capacities. To explore how these different components might affect results under climate change-induced hydrologic conditions and to extract information that may be applied to different systems, a sensitivity analysis was performed on some model parameters representing the system's infrastructure. This sensitivity analysis was also performed to understand why the "timing" effects of climate change on hydropower generation revenues where not as pronounced as expected in the previous section.

The parameters explored in this sensitivity analysis are reservoir capacity and the pattern of energy prices. The sensitivity analysis shows, as expected, that increasing the size of reservoirs increases generation and that reducing their size decreases generation. Generation patterns with increased reservoir sizes tends to more closely match the pattern of energy value. On the other hand, generation patterns with reduced storage capacity more closely reflects the hydrograph pattern, with an increase in late winter and spring generation/ revenues as compared with the original case. However, none of the results so far finds an effect of climate change, or a disparity between the results of the different climate change scenarios, that cannot be explained mainly by changes in annual inflow. Even under very stressed conditions due to reduced storage capacity, there is not a clear effect on energy generation revenues of changing either the timing of inflows or the pattern of high-flow events. To explore the effects of streamflow timing changes, we perform a final LP analysis that considered a slight change in the pattern of energy prices.

The original energy pricing pattern shows a markedly high value during July through September, a middle value during October through December, and a low value the rest of the year (see Fig. 6a). For the new runs, we increase the energy price in June to match the July's high price. The results of one of these new scenarios, that also considered a reduction of 75% in reservoir storage capacity are shown in Table 2. In Fig. 10 we compare the percent change in energy revenues (as compared to historical conditions) from this "high-June-energy-reduced-storage" or "HJune75%" scenario, with the percent change in energy

Table 2 Comparison of different outputs from the system for all hydrologic scenarios for a scenario with system storage reduced to a fourth and modified June energy price (HJune75%)

		Generation						
		Million Dollar/year			GWh/year			
	Inflow (TAF/year)	On	Off	Total	On	Off	Total	Average Spills (TAF/year)
Historical	491	46	19	64	772	789	1,560	178
GFDLA2	448	42	14	56	707	602	1,310	246
GFDLB1	442	44	15	59	757	655	1,413	133
PCMA2	589	46	20	66	806	905	1,711	326
PCMB1	544	46	20	66	803	880	1,683	227

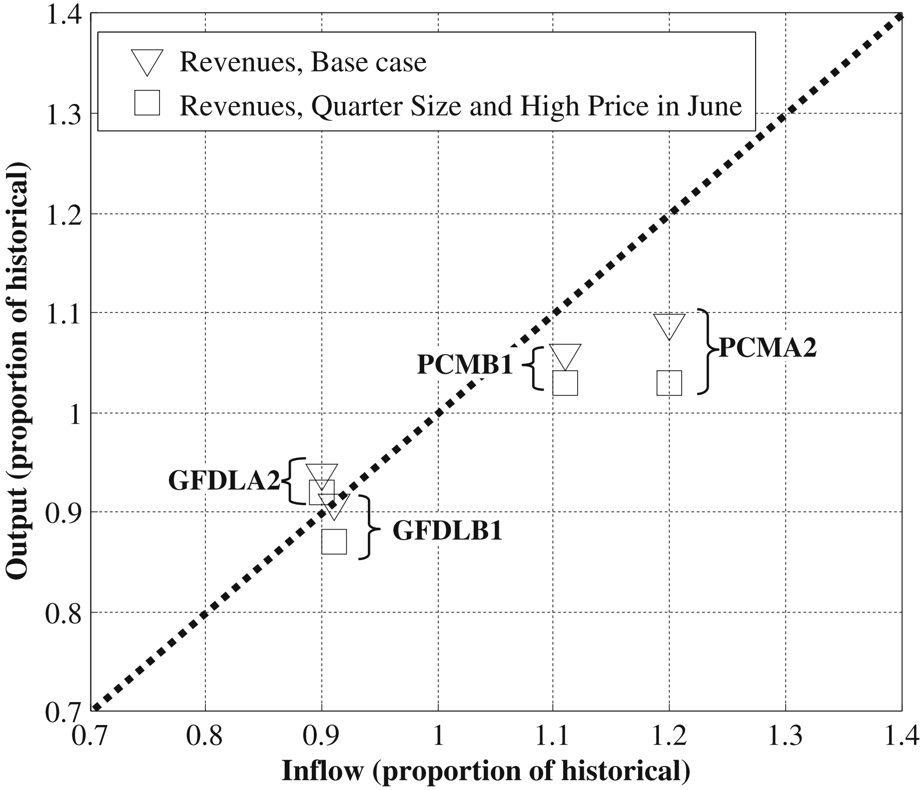


Fig. 10 Comparison of annual energy revenues (as compared to historical conditions) for different climate change scenarios for the base case and a hypothetical case were storage capacity is reduced to a fourth and energy price in June is increased to match the price in July

revenues from the base scenario. Under this HJune75% scenario we finally see a significant impact of the "inconvenience" of the hydrologic timing associated with climate change. We see, for example, that only one of the scenarios (GFDLB1) predicts a change in revenues that is smaller than the change in inflows. Under the HJune75% scenario the GFDLA2 climate shows a reduction in revenues larger than its reduction in inflows. This occurs even though there is less water in the system, and hence there should be more flexibility to use that water efficiently. However, the system is not flexible enough to handle GFDLA2's large timing effects; the reduced storage capacity does not allow the system to store water and it has to generate during the less-valuable winter and spring months, reflecting the inflow timing. The hydrologic timing also affects operations under PCMA2, which predicts having almost 20% more water than the historical case, but which sees only a modest increase (~3%) in revenues.

4 Conclusions

To better understand the impacts of climate change on high elevation hydropower generation in California, we formulated a linear programming model of an 11-reservoir hydroelectric system Upper American River basin. Hydrologic conditions under four climate change scenarios were developed using output from the Variable Infiltration Capacity model, run using climatic output from two GCMs under two emissions scenarios.

We find that hydropower generation and revenues fall under drier climate change scenarios and increase in scenarios with wetter conditions. The decline is greater in terms of energy generation than in terms of energy revenues, reflecting the continued ability of the system to store water when energy prices are low for use when prices are high (July through September). There were also small but clear effects due to changes in the timing of inflows and to the magnitude and incidence of high flows. The effects of these hydrograph changes on energy generation were less than expected, considering the size of the changes under the climate change scenarios. It was expected that a hydrograph with a centroid occurring months earlier than the high value months in summer would have greatly reduced energy revenues. Similarly it was expected that a scenario with greater floods in winter would have increased spillage during the winter and reduced stored water available for high value summer months.

To understand why our expectations were not met, a sensitivity analysis was performed on different aspects of the system. One of the parameters we tested is the storage capacity of the system. Under increased storage capacity, the pattern of energy generation revenues closely match the pattern of energy pricing, while with reduced storage capacity energy generation revenues match streamflow conditions. However, we did not find a particular impact due to the changes in hydrologic timing predicted by the climate change scenarios.

Only when the energy price for the month of June was changed did the impact of the timing effect on revenues occur as expected. The reason is as follows. The model originally had a very low energy price in June compared to the energy prices in July through September. Historical, unimpaired streamflow did not include significant inflows in the months from July–September (the last month with significant inflows being June). Thus, changes in winter and spring hydrologic timing associated with the climate change scenarios can not significantly reduce flow in these high value months. However, the change in timing does affect June streamflow, and thus increasing energy prices in June did affect total revenues for this system. The effect of raising the energy price in June is similar to having an initial hydrograph with significant inflows in July, the first month with high energy prices.

In summary, we expect that hydroelectric systems located in basins with significant inflows during the late spring and early summer months will be affected by the changes in the timing of streamflows, as predicted under climate change conditions, provided they lack sufficient storage capacity to accommodate these changes. If the system has sufficiently large storage capacity these timing effects should not affect its generation capacity. More work remains to be done to investigate the effects that a change in maximum flows might have on the operation of the system. This will require a better representation of the uncertainties faced by the operators of the systems and will be included in future refinements of the model presented here.

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