CLIMATE CHANGE IMPACTS ON HIGH-ELEVATION HYDROPOWER GENERATION IN CALIFORNIA'S SIERRA NEVADA: A CASE STUDY IN THE UPPER AMERICAN RIVER

A Report From:
California Climate Change Center

Prepared By:
Sebastian Vicuña, Rebecca Leonardson, John A. Dracup, Department of Civil and Environmental Engineering, U.C. Berkeley

Michael Hanemann, Department of Agriculture and Resource Economics, U.C. Berkeley

Larry Dale, Lawrence Berkeley National Laboratory

WHITE PAPER

DISCLAIMER

STATE OF CALIFORNIA ENERGY COMMISSION

Arnold Schwarzenegger, *Governor*

March 2006
CEC-500-2005-199-SF

Acknowledgements

We would like to acknowledge Jery Stedinger, Richard McCann, and Edwin P. Maurer for their help and advice in this project. We also thank Jim Woodward, the Sacramento Municipal Utility District (SMUD), and one anonymous reviewer for their useful comments and review. Funding for this project came from the California Climate Change Center at U.C. Berkeley.

Preface

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

The PIER Program, managed by the California Energy Commission (Energy Commission), annually awards up to $62 million to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

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

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

The California Climate Change Center (CCCC) is sponsored by the PIER program and coordinated by its Energy-Related Environmental Research area. The Center is managed by the California Energy Commission, Scripps Institution of Oceanography at the University of California at San Diego, and the University of California at Berkeley. The Scripps Institution of Oceanography conducts and administers research on climate change detection, analysis, and modeling; and the University of California at Berkeley conducts and administers research on economic analyses and policy issues. The Center also supports the Global Climate Change Grant Program, which offers competitive solicitations for climate research.

The California Climate Change Center Report Series details ongoing Center-sponsored research. As interim project results, these reports receive minimal editing, and 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 contact the Energy Commission at (916) 654-5164.

Table of Contents

List of Figures

List of Tables

Abstract

To investigate the possible impacts of climate change on high-elevation hydropower generation in California, this study developed a linear programming model of the 11-reservoir hydroelectric system operated by the Sacramento Municipal Utility District in the Upper American River Project. Hydrologic conditions under climate change scenarios were developed from hydrologic results predicted for nearby locations by the Variable Infiltration Capacity model run using climatic output from two general circulation models under two emissions scenarios.

Results showed that power generation and revenues drop under all climate change scenarios as a consequence of drier hydrologic conditions. Energy generation dropped 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). Results indicate that hydroelectric systems located in basins with significant inflows close to summer months are likely to be affected by the timing effects associated with climate change (e.g., earlier snowmelts and streamflows) if the systems lack sufficient storage capacity to accommodate these changes (both storage capacity to hold water until it is needed to generate electricity, and capacity to absorb late high flows). High Sierra hydroelectric systems with sufficiently large storage capacity should not be affected by climate-related timing changes.

Executive Summary

Using the head potential and snow storage existing in high-elevation basins of the Sierra Nevada Mountains, a number of utilities manage a complex infrastructure of hydropower generation systems that contributes significantly to all electricity generated statewide. These systems are fed by stream inflows created by precipitation in winter months and snowmelt during the spring season. It is expected that under a climate change scenario, California's hydrology would experience an earlier timing of streamflows. This shift is associated with the increase in temperature, leading to a higher proportion of precipitation falling as rain (as compared to snow) and an earlier spring snowmelt runoff. The two effects could impact 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 wintertime could lead to greater spillage and less overall energy generation.

In order to study these potential effects, this project developed a linear programming model of the 11-reservoir hydroelectric interconnected system, with storage capacity of over 425,000 acre-feet (ac-ft) and generation capacity of 688 megawatts (MW) operated by the Sacramento Municipal Utility District (SMUD) in the Upper American River watershed. The study developed hydrologic conditions under climate change scenarios considering the effects on locations close to the system, as predicted by the Variable Infiltration Capacity (VIC) model, a macroscale hydrologic model developed by the University of Washington. VIC was run using climatic output from two general circulation models (GCMs) that had been run under two emission scenarios.

The results show that hydropower generation, in terms of energy generated and revenues, drops in all climate change scenarios as a consequence of drier hydrologic conditions. The drop is greater in terms of energy generation than in terms of energy revenues, reflecting the ability of the system to store water when energy prices are low, and then release water when electricity demand and prices are high (July through September). Contrary to expectations, there was no clear effect on annual energy generation associated with either changes in the timing of inflows or the magnitude and occurrence of high flows.

A sensitivity analysis of the most relevant parameters in the system provided understanding of how hydroelectric systems in different basins will behave under a climate change scenario. An increase in total storage capacity would allow the storage of more water arriving during winter and spring months to be used to generate electricity in summer months, improving overall energy revenues for all climatic scenarios, including the historical condition. Reducing storage capacity would reduce this ability to "move" water in time and would force the system to generate at a pattern closer to the hydrograph pattern. Under neither storage capacity scenario was there a clear effect of the earlier timing of inflows associated with climate change conditions. The reason: the pattern of energy prices throughout the year is not correlated with either the historical or the climate change hydrograph, so there is no loss of generation due to the hydrograph timing change. This was revealed in a final scenario with a different energy price for the month of June, which originally was set at a very low value ($18/MWh) as compared to the energy prices in the three following months July through September ($30/MWh). Running the model with a reduced storage capacity and this new energy price pattern showed a clear impact from those climate change conditions that had a significant earlier streamflow pattern.

Another insight gained through this sensitivity analysis is that the system as modeled in this project can handle large streamflow events, minimizing the amount of water spilled without passing through the turbines. Two major factors contribute to this ability to handle high-flow events:

- The system contains a multitude of reservoir interconnections, which allow water spilled from one reservoir (that has reached some capacity constraint) to generate in the same month using a reservoir downstream with idle capacity.
- The study assumed the system acts with perfect foresight in terms of daily streamflow, within a month horizon. This power of perfect foresight allows system to operate in a rather unrealistic way that accommodates the advent of large streamflow events. A refinement to the model used in this project could include a smaller time horizon for the daily optimization (5–7 days) that would better reflect the uncertainties associated with potential flood events and the reliability limits of current weather forecasting models. This refinement would also better capture their associated impacts under a climate change scenario.

In summary, hydroelectric systems located in basins with significant inflows close to summer months are likely to be affected by the timing effects associated with climate change conditions if they lack sufficient storage capacity to accommodate these changes (both storage capacity to hold water until it is needed to generate electricity, and capacity to absorb late high flows). High Sierra hydroelectric systems with sufficiently large storage capacity should *not* be affected by these timing changes.

There is still more work to be done to fully investigate how a change in maximum reservoir inflows might affect system operation. This will require a better representation of the uncertainties faced by system operators and a better representation of their operating objectives. These enhancements will be included in future refinements of this work.

1.0 Introduction

Using the head potential and snow storage existing in high-elevation basins of the Sierra Nevada Mountains, public and private utilities manage a complex infrastructure of hydroelectric generation that makes up almost 50% of all hydropower generated statewide (Aspen Environmental and M-Cubed 2005). These systems vary in terms of storage capacity, conveyance capacity, and altitude. Those systems with very little storage capacity (run-of-river systems) generate electricity as a function of streamflow (or releases from upstream reservoirs) and are unable to store flows in excess of their turbine capacities. In cases where storage is more significant, the system is able to store excess water and release it through the turbines at a later time. Two important objectives in the operation of a hydropower system are (1) to generate electricity when demand is higher and hence 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 rather than in the winter.

The most consistent prediction of previous studies on the effects of climate change on California hydrology is an earlier timing of streamflows over the next 100 years. These shifts are associated with the increase in temperature, leading to a higher proportion of precipitation falling as rain (as compared to snow) and an earlier spring snowmelt runoff. These two effects could induce a timing mismatch between energy generation and energy demand, thereby impacting the operations of high-elevation hydropower reservoirs with low storage capacity. Additionally, higher inflows in wintertime could lead to greater spillage and less overall energy generation.

This paper examines the potential effects of climate change–induced hydrological changes on high-elevation hydropower generation in California. The research focused as a case study on the Sacramento Municipal Utility District (SMUD) hydroelectric system, known as the Upper American River Project, located in El Dorado and Sacramento Counties within the Rubicon River, Silver Creek, and the South Fork American River drainages, on the west slope of the Sierra Nevada mountain range.

2.0 Upper American River Project

SMUD's Upper American River Project (UARP) 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 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): [1]

- The Loon Lake Development consists of three dams and reservoirs, three tunnels, and a powerhouse. This connected set of dams captures inflowing waters from the Rubicon River and some other small creeks, transporting them finally to the Loon Lake Reservoir (the largest reservoir in the development) via a series of tunnels. From Loon Lake Reservoir, the water drops into a subterranean powerhouse 1,100 feet (335 m) below the surface of the reservoir. Tailrace water exiting the 82-MW Loon Lake Powerhouse travels through a 3.8-mile (6.1 km) tunnel before entering Gerle Creek Reservoir. Water is also released from the base of each of the three dams into the respective natural streambeds to preserve and protect downstream aquatic resources.

- The Robbs Peak Development consists of two dams, two reservoirs, a canal, tunnel, penstock, and powerhouse. The first dam lies on Gerle Creek and captures the tailrace water of the Loon Lake Powerhouse and inflowing water of the creek. Water from the reservoir is transported 1.9 miles (3.1 km) via a canal to the small Robbs Peak Reservoir, from which water is transported via a tunnel and penstock to the 29-MW Robbs Peak Powerhouse, located on the northeast shore of the Union Valley Reservoir.

- The Jones Fork Development consists of a dam, reservoir, tunnel, penstock, and powerhouse. The dam lies on the South Fork Silver Creek and captures inflowing creek water to create Ice House Reservoir, at elevation 5,450 feet (1,661 m). From Ice House Reservoir, water is transported via a tunnel and penstock to the 11.5-MW Jones Fork Powerhouse, located on the southeast shore of Union Valley Reservoir, adjacent to Jones Fork Silver Creek. Water is also released from base of the dam into South Fork Silver Creek to preserve and protect downstream aquatic resources.

- The Union Valley Development consists of a dam, reservoir, tunnel, penstock, and powerhouse. The dam lies on Silver Creek and captures inflowing water of several sources to create the 277,290 acre-foot Union Valley Reservoir—the largest storage reservoir of the Project, at elevation 4,870 feet (1,484 m). The sources of water flowing into the reservoir include the direct outflows of both Robbs Peak and Jones Fork powerhouses, as well as the inflow of Big Silver Creek, Jones Fork Silver Creek, Tells Creek, and Wench Creek. Water is transported from Union Valley Reservoir, via a

1. What follows is a concise description of UARP system and operations based on the Initial Information Package (IIP) documentation for UARP relicensing project (SMUD 2001).

penstock through the dam, to the 46.7-MW Union Valley Powerhouse, lying at the base of the dam. Water exiting the powerhouse flows directly into Junction Reservoir.

- The Jaybird Development consists of a dam, reservoir, tunnel, penstock, and powerhouse. The dam lies on Silver Creek and captures water exiting Union Valley Powerhouse and flowing down South Fork Silver Creek, creating the 3,250 ac-ft Junction Reservoir. Water is transported from the reservoir to the 144-MW Jaybird Powerhouse. Water exiting the powerhouse immediately enters Camino Reservoir. Water is also released from the base of the dam into Silver Creek to preserve and protect downstream aquatic resources.

- The Camino Development consists of two dams, reservoirs, and tunnels, with one penstock and powerhouse. The first dam lies on Silver Creek and captures inflowing water from the creek and water exiting the Jaybird Powerhouse to create the Camino Reservoir. Water is released from the reservoir into a tunnel leading to the 150-MW Camino Powerhouse. The tunnel is joined by a second tunnel bringing water from Brush Creek Reservoir. The combined water drops through a penstock into the Camino Powerhouse, which lies along the South Fork American River. Water exiting the powerhouse immediately enters the Slab Creek Reservoir.

- The Slab Creek/White Rock Development consists of one dam and reservoir, two penstocks, and two powerhouses. The dam lies on the South Fork American River and captures inflowing creek river water and tailrace water from Camino Powerhouse. Water is released from the reservoir into the small Slab Creek Powerhouse. Water released from the powerhouse immediately enters the natural streambed of the South Fork American River to protect and preserve downstream aquatic resources. Water is also released from the Slab Creek Reservoir into White Rock Powerhouse. Water released from the powerhouse immediately enters Chili Bar Reservoir, part of the Pacific Gas and Electric Company's Chili Bar Project.

The UARP is the only hydroelectric project owned by SMUD. The Project plays a significant role in energy management, contributing value in three primary areas: (1) operational flexibility, (2) economical power generation, and (3) overall system reliability. One of the primary aspects of operational flexibility lies in the ability of the Project to store water on a seasonal basis. The combined 400,000 ac-ft gross capacity afforded by the three Project storage reservoirs enables SMUD to manage the water—within physical, safety, and regulatory constraints—to generate electricity when power is most valued throughout the year. The Project is also operated to ensure reliability of the electric generation and transmission systems within SMUD's service area and in northern California. The Project is operated in a manner to instantaneously provide electricity during emergency and other limited situations, and to provide regulation services to the California Independent System Operator (Cal ISO).

From a water management perspective, the operation of the Project follows an annual cycle of reservoir filling and release that coincides with the natural patterns of rain and snowmelt runoff characteristic of the Sierra Nevada. Three reservoirs (Loon Lake, Ice House, and Union Valley), accounting for 94 percent of total Project gross storage capacity, are operated primarily as seasonal storage reservoirs, impounding as much of the winter/spring rain and snowmelt runoff as practicable, consistent with various regulatory, dam safety, water rights, and FERC operational requirements. The two uppermost reservoirs (Rubicon and Buck Island) provide limited storage and are operated primarily as run-of-the-river reservoirs to capture and divert water from the Rubicon River and the Highland Creek drainages. Typically, from about mid-summer to mid-fall each year, the elevations of the three primary storage reservoirs are gradually lowered to generate electricity and provide adequate storage space to store winter/spring runoff and minimize the frequency and amount of spillage. Reservoir elevations then slowly rise during the spring and early summer as rain and snowmelt runoff fill the reservoirs. Five of the Project reservoirs (Gerle Creek, Robbs Peak, Junction, Camino, and Slab Creek) are operated primarily as re-regulating forebays and/or afterbays to the various powerhouses.

Table 1. System components included in the model

	COMPONENT						
PARAMETER	Loon Lake	Robbs Peak	Union Valley	Jones Fork/ Ice House Res.	Jaybird	Camino	White Rock/Slab Cr. Res.
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 (ac-ft)	78,720	1,260	277,290	45,960	3,250	825	16,600
Reservoir depth (ft)	165	21	360	52	141	76	186
Depth/Head	15%	6%	86%	9%	9%	7%	22%
Penstock flow 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

3.0 Methodological Approach

The project approach comprised the following steps:

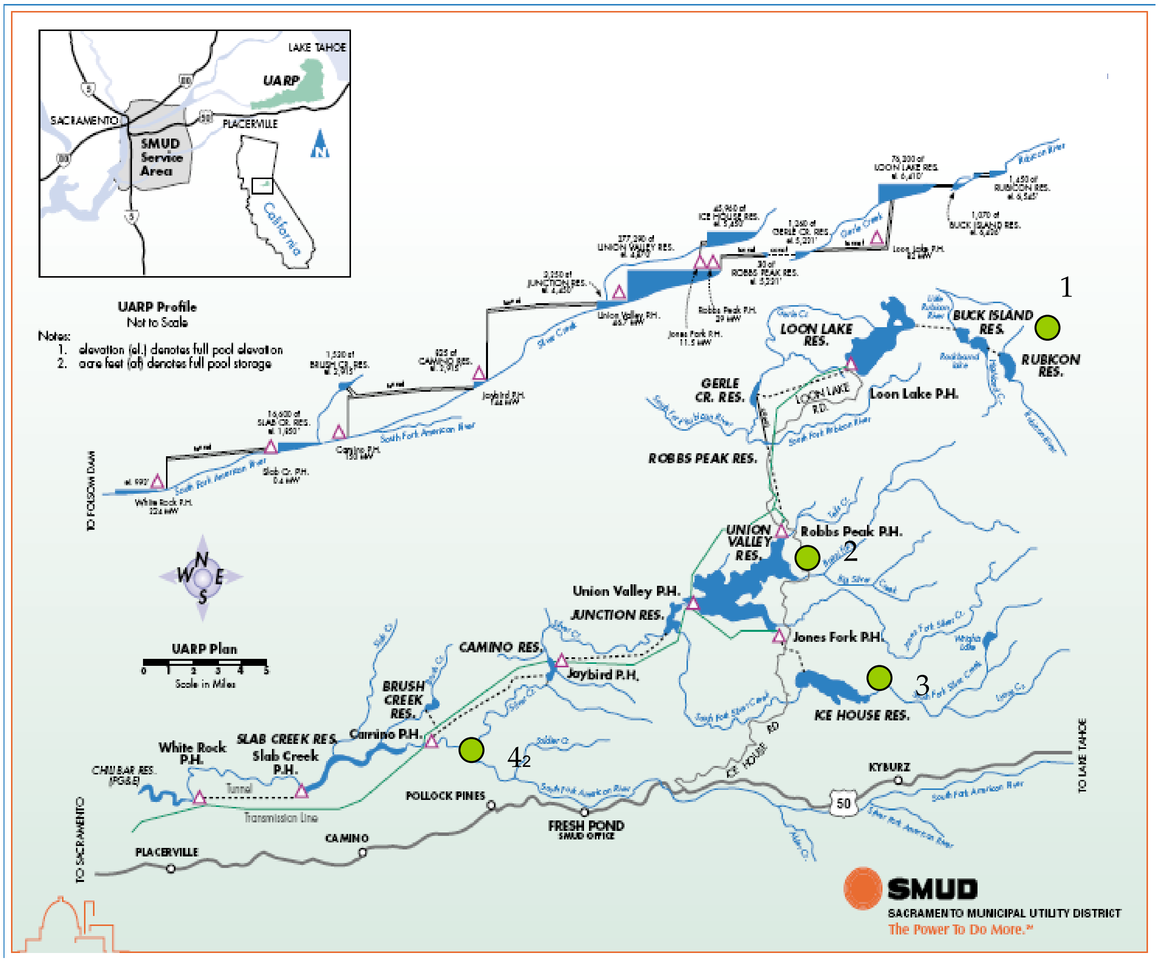
- Constructing a time series of daily and monthly historical unimpaired streamflows into the system using USGS (United States Geological Survey) streamflow data where available (and extensions of the same by correlation analysis)
- Perturbing daily and monthly data using climate change signals (for the four GCM/emission scenarios described in Section 3.2) for VIC grid points located close to the system
- Performing a sequential, multi-step, linear optimization of energy production for the system under both historical and climate change conditions, assuming constant head. Under each sequence, one month was optimized at a daily time step and the subsequent 11 months were optimized at a monthly time step. This avoided the use of carryover value functions and minimized some of the bias associated with the "perfect foresight" approach. The output from this step was average monthly energy production and value and spill amounts, which were compared for different hydrologic scenarios.
- Performing a sensitivity analysis of key system parameters (e.g. storage capacity) to understand how other systems with different conditions might respond under the same kind of climatic stresses.

This section of the paper describes these steps in more detail.

3.1. Development of Historical Time Series

The SMUD UARP is located in El Dorado County within the Rubicon River, Silver Creek, and the South Fork American River (SFAR) drainages. Figure 1 shows a map of the system and a schematic of its major components. Four major rivers/creeks feed into the Upper American Project: the Rubicon River, Silver Creek, South Fork Silver Creek, and South Fork American River. These inflows are denoted in Figure 1 by numbers 1 to 4, respectively. Information about the watersheds is summarized in Table 1.

A major effort in this project was to develop an overlapping record of daily inflows to the system for a period before the projects were built (i.e., a record of unimpaired daily streamflow). Fortunately, two of the watersheds that feed into the system have daily streamflow USGS gage records dating back into the 1920s (gages 11441500, on South Fork Silver Creek near Ice House, and 11441000, on Silver Creek at Union Valley). Inflow representing the Rubicon River was constructed to match a 1934–1950 flow prediction reported by Bechtel in 1958 and reprinted by SMUD (2001). This was built using correlation with USGS monthly streamflow data from nearby gauging stations (the adjusted R^2 in the correlation analysis was greater than 0.99 except for 1940–1943, when it was 0.90). Finally, daily and monthly streamflow were estimated for the same period (1924–1960) for the full flow of the South Fork American River where it meets Silver Creek. Unfortunately, no gauging station measured streamflow throughout the study period on the South Fork near this confluence. Correlating daily USGS streamflow data downstream of the gauging station with contributions from Silver Creek (station 11442000) and gauging station 11439500, which is upstream of several tributaries, indicates that the South Fork contributes about 1.3 times the flow as station 11439500. This relationship was used to derive both daily and monthly inflows from the South Fork American River.



Source: SMUD (2001)

Figure 1. Upper American River Project

Table 2. Study basins

River	Reservoir(s)	Storage Capacity (ac-ft)	Site Elevation (ft)	Drainage Area (mi^2)
Rubicon	Rubicon Res.	1,450	6,545	26.1
	Rockbound Lk.			
Rubicon	Buck Island Lk.	1,070	6,436	14.2
	Loon Lake	6,436	6,410	(all three)
South Fk. Silver Creek	Ice House Res.	45,960	5,450	27.2
Silver Creek	Union Valley	277,290	4,870	83.7

Source: SMUD (2001)

A time period covering 1928 through 1949 was selected to represent historical conditions in the system. As this was before the installation of the reservoir system, the data represent mostly unimpaired streamflow. Table 3 shows monthly statistics of the time series of streamflows used to represent historic conditions.

Figure 2 shows monthly average streamflow conditions for Silver Creek representing inflows into Union Valley reservoir. The data shown are mean daily flows within the month, as well as the maximum and minimum daily streamflows of each month, as averaged over the study period. The streamflow pattern includes two peak natural streamflow conditions—a smaller peak occurring in winter (floods) and a larger peak occurring in spring (snowmelt runoff). Flows drop significantly in July.

Figure 3 shows the same data for South Fork Silver Creek, representing inflows into Ice House Reservoir. The pattern is similar to Figure 2 perhaps with a more pronounced hump for maximum streamflows in winter. Figure 4 shows inflows to the combined Rubicon River system, which shares a common pattern with South Fork Silver Creek, with perhaps an even more pronounced hump (peak) occurring in wintertime.

Table 3. Monthly natural flow (cfs) statistics for major inflows into the UARP system, based on daily mean flow values for historic period (1928–1949)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
South Fork Silver Creek at Ice House												
Minimum	0.7	0.6	2.3	3.0	3.0	6.9	55	66	35	2.9	0.2	0.2
90%(dry)	0.7	1.4	3.7	3.7	8.2	15.8	62	97	38	4.1	0.6	0.5
50%(median)	2.6	9.9	13	17	25	48	149	313	159	29	3.3	1.0
10%(wet)	16	45	74	71	66	158	247	424	363	68	10	3
Maximum	28	51	131	84	79	191	280	443	409	104	11	4
Silver Creek at Union Valley												
Minimum	5.9	2.4	2.6	4.0	4.6	10.8	16	18	33	7.0	2.6	2.8
90%(dry)	6.4	5.5	4.3	5.4	9.8	14.8	27	43	61	10.9	3.9	4.0
50%(median)	11	34	35	57	95	161	448	732	287	66	9.7	6.6
10%(wet)	58	124	265	368	375	584	831	1023	757	530	722	456
Maximum	96	155	454	421	414	775	913	1364	778	649	904	629
South Fork American												
Minimum	1.0	0.6	0.9	0.7	1.0	3.1	228	201	36	1.1	2.1	2.7
90%(dry)	2.3	2.0	2.0	1.7	3.4	11	296	356	64	3.1	2.6	3.0
50%(median)	5	12	12	31	73	201	835	1607	800	60	3.9	4.4
10%(wet)	67	163	297	330	419	861	1416	2207	2147	384	10	10
Maximum	98	203	648	456	526	928	1663	3196	2474	497	11	16
Rubicon at Rubicon												
Minimum	1.8	3.7	3.7	4.3	5.0	9.7	11	12	18	0.0	0.0	0.0
90%(dry)	2.4	4.4	4.6	5.5	9.1	12	16	22	30	6.1	0.0	0.0
50%(median)	8.9	20	15	26	50	78	213	278	137	34	6.1	4.4
10%(wet)	34	65	124	131	157	231	374	472	306	244	332	211
Maximum	46	102	210	165	186	249	422	625	358	299	415	290

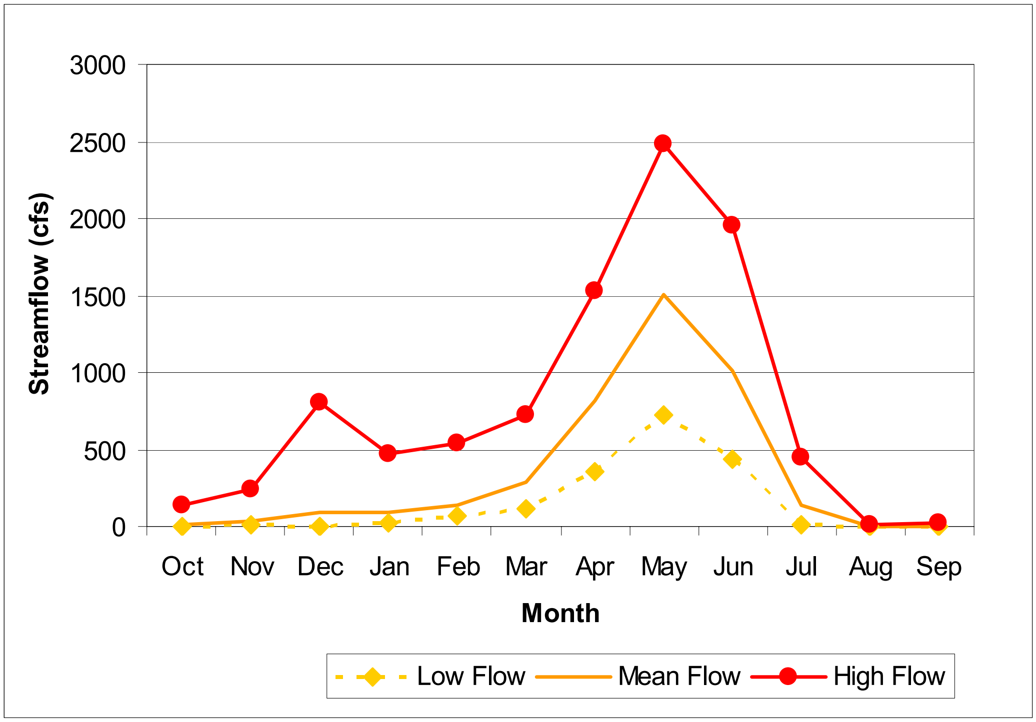


Figure 2. Unimpaired (pre-dam) inflows to Union Valley, 1928–1949 (historic scenario)

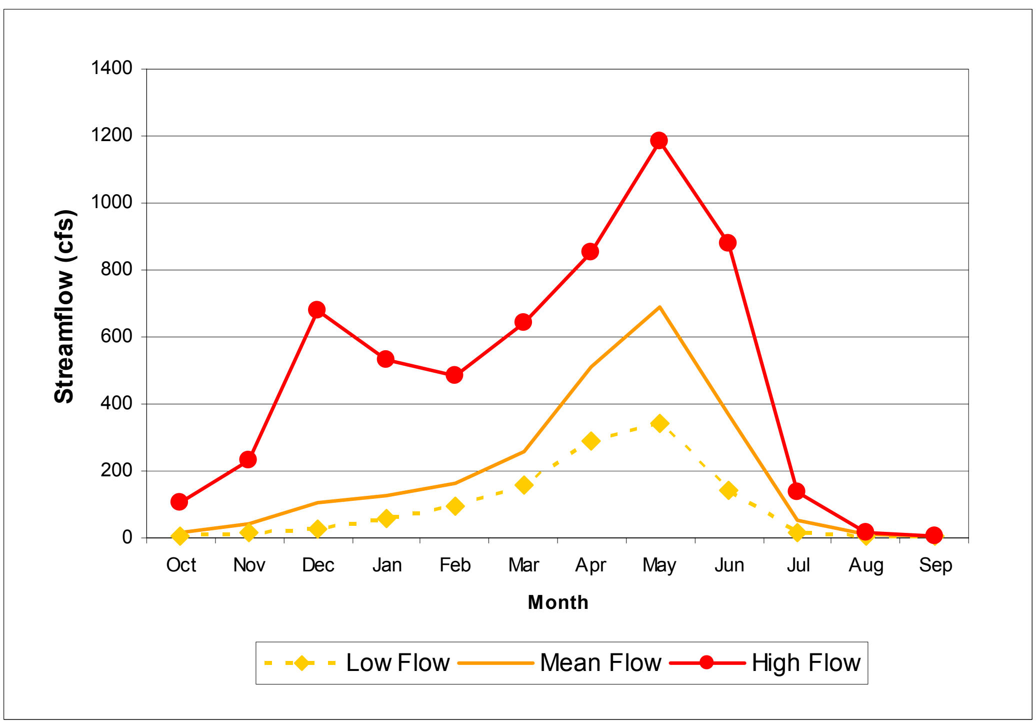


Figure 3. Unimpaired (pre-dam) inflows to Ice House, 1928–1949 (historic scenario)

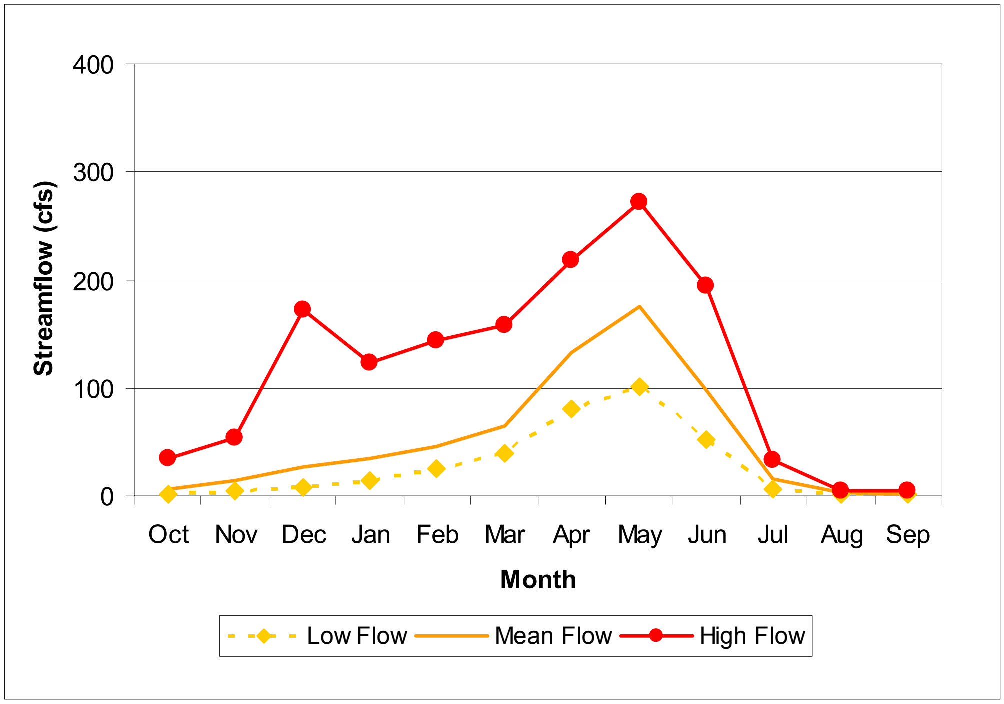


Figure 4. Unimpaired (pre-dam) inflows to Rubicon system, 1928–1949 (historic scenario)

3.2. Development of Perturbation Ratios

Eight sets of daily and monthly streamflow predictions were used to develop perturbation ratios. These eight data series are hydrologic representations of streamflow at the two closest VIC[2] grid output locations (Lat/Long: 39.0625/120.1875 and 38.8125/120.4375, denoted hereafter as grids 39 and 38), based on climate output as predicted by the NCAR PCM and GFDL CM2 climate models[3] run under the greenhouse gas emission scenarios SRES A2 and SRES B1.[4] That is, simulations were run for two locations (38, 39), under two different models

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. This study used two general circulation models: the Parallel Climate Model (PCM) developed by the National Center for Atmospheric Research, and the GFDL CM2 (commonly referred to as GFDL) developed by the Geophysical Fluid Dynamics Laboratory and the National Oceanic and Atmospheric Administration.

4. 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 CO_2 emissions. These climate change scenarios considered in this study were selected in a attempt to bracket the uncertainty existing among models on California climate change climatic predictions. A description of the scenarios and the hydrologic model VIC can be found in Cayan et al. (2006).

(PCM, GFDL), for two different greenhouse gas scenarios (A2, B1), yielding a total of eight perturbation ratios. Unimpaired natural streamflow representing the period 1960–1990 as predicted by the GCM (not actual historical streamflow) was compared with streamflow predictions for 2070–2099.

The perturbation ratio is a simple ratio of streamflows predicted by a GCM for different eras, for the corresponding time period (i.e., month). This can then be used to perturb a historical data series as an alternative to using pure model output. The development of monthly perturbation ratios was a straightforward procedure that consisted of obtaining streamflow averages for each month in both the historical and future climate change predictions. Figure 5 shows the monthly perturbation ratios for the eight climate change scenarios.

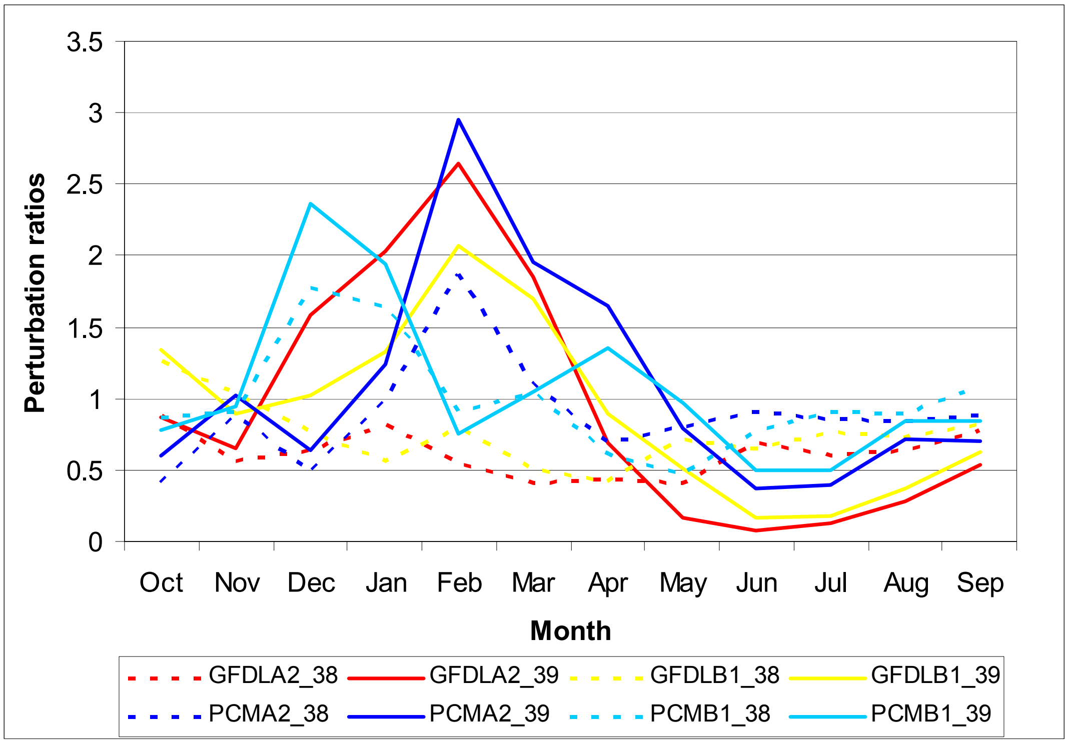


Figure 5. Monthly perturbation ratios (based on 2070–2099 climate change conditions)

The general trend that can be appreciated 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 an earlier timing of inflows. The behavior is similar under all scenarios except the two GFDL predictions for grid 38, where there are no increases in any given month. (It is not clear why the results in this grid are so different from the results for the other scenarios). In order to get a representative sample of all potential impacts, the following climate scenarios were analyzed: GFDLA2_38, GFDLA2_39, PCMB1_38 and PCMB1_39.[5]

To develop the daily perturbation ratios for these scenarios, each month was divided into equal-sized sets of wet, normal, and dry days.[6] Averages were then taken of all wet January days, all normal January days, and so on, for both the historical and climate change–predicted periods. This yielded three series of monthly perturbation ratios for each climate change scenario, allowing both average and extreme hydrograph changes to be tracked. Daily perturbation ratios are shown in Figure 6 for all climate scenarios considered in the analysis.

The results show that, in general, daily maximum streamflows increase more than medium and low streamflows. The clearest example is the case of the GFDLA2_39 scenario. Figures 7 and 8 show the translation of these perturbation ratios into the simulated streamflow conditions, comparable to Figures 2 and 3 (excluding effects on the Rubicon River system). The results show the expected earlier timing of inflows and, interestingly, a more pronounced hump of flood conditions in winter months. The most extreme case is GFDLA2_39, which basically shifts the high streamflow timing from May to February. Table 4 shows changes to annual streamflow for the whole system for all scenarios.

Table 4. Change in annual average streamflow (in TAF*/year and as percent of historical inflow)

	Scenario				
	Historical	PCMB1_38	PCMB1_39	GFDLA2_38	GFDLA2_39
Annual Average Inflow into System	491	348 (71%)	420 (86%)	307 (62%)	422 (86%)

* TAF = thousand (1,000) acre-feet

5. The results for GFDLA2 and PCMB1 bracket the possible impacts of climate change in California (see Cayan et al. 2006).

6. Generally the extra day would be added to the normal set, so that January has 10 wet, 11 normal, and 10 dry days.

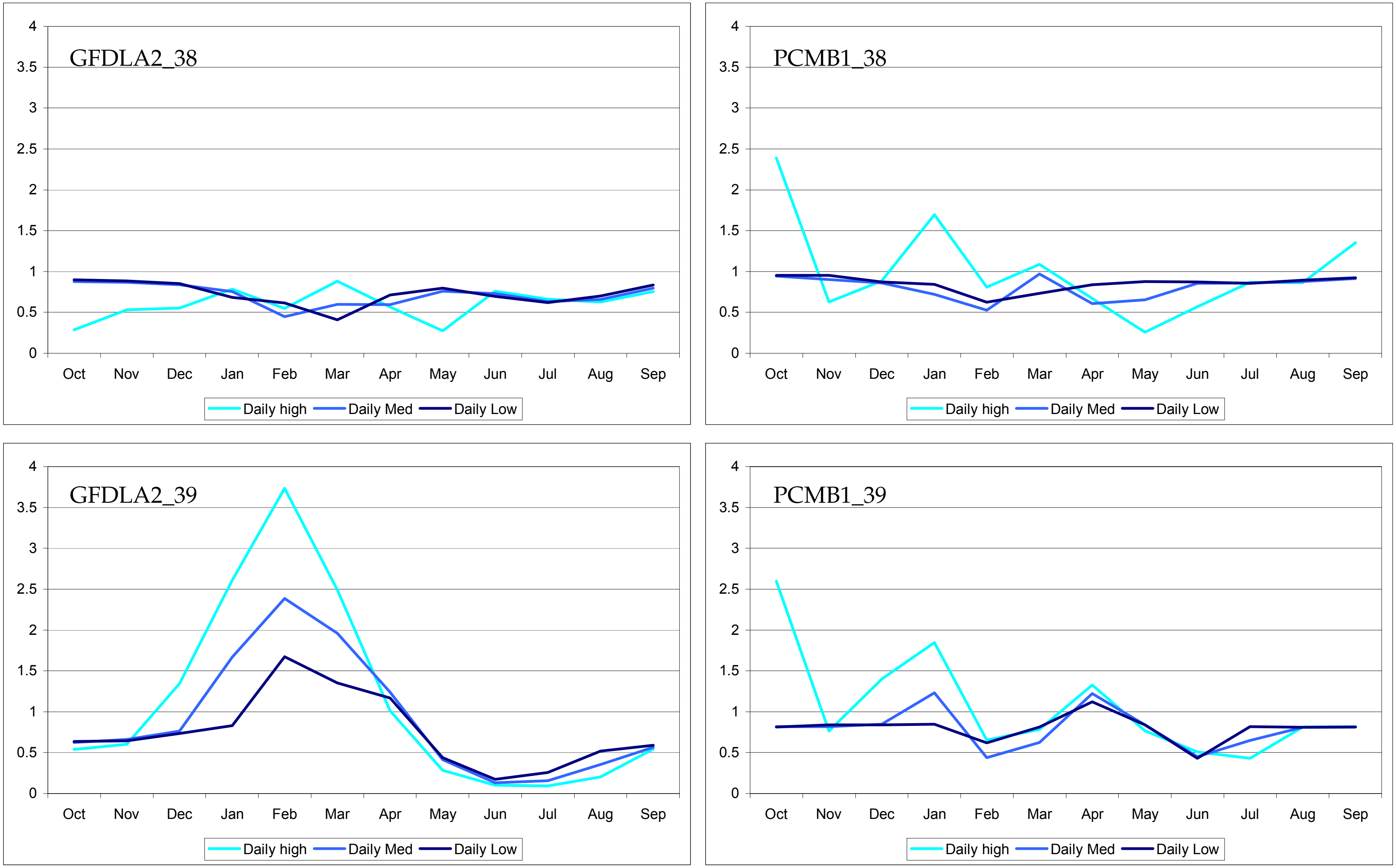


Figure 6. Daily perturbation ratios (based on 2070–2099 climate change conditions)

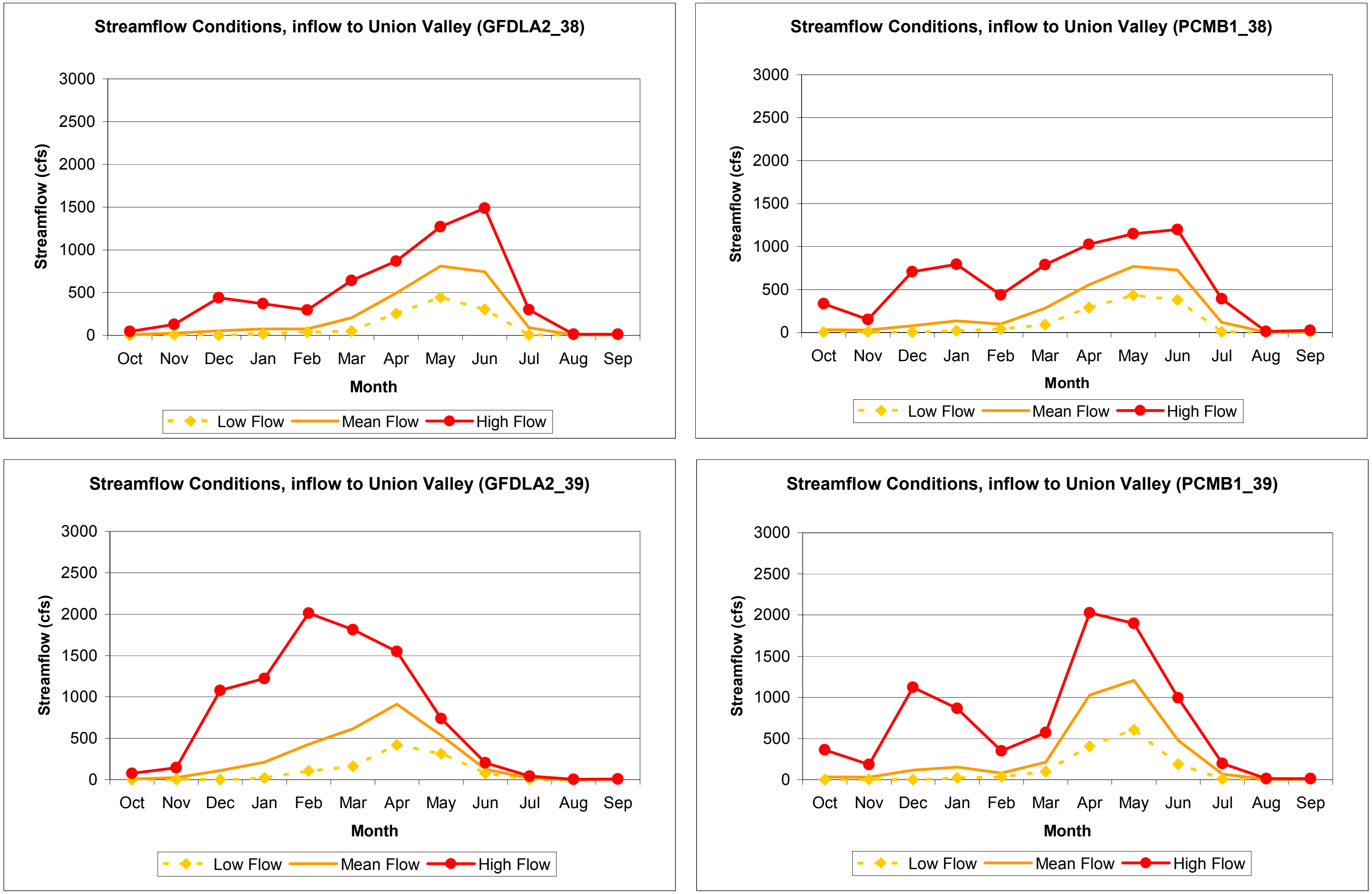


Figure 7. Streamflow conditions (unimpaired inflow to Union Valley) under climate change scenarios 2070–2099

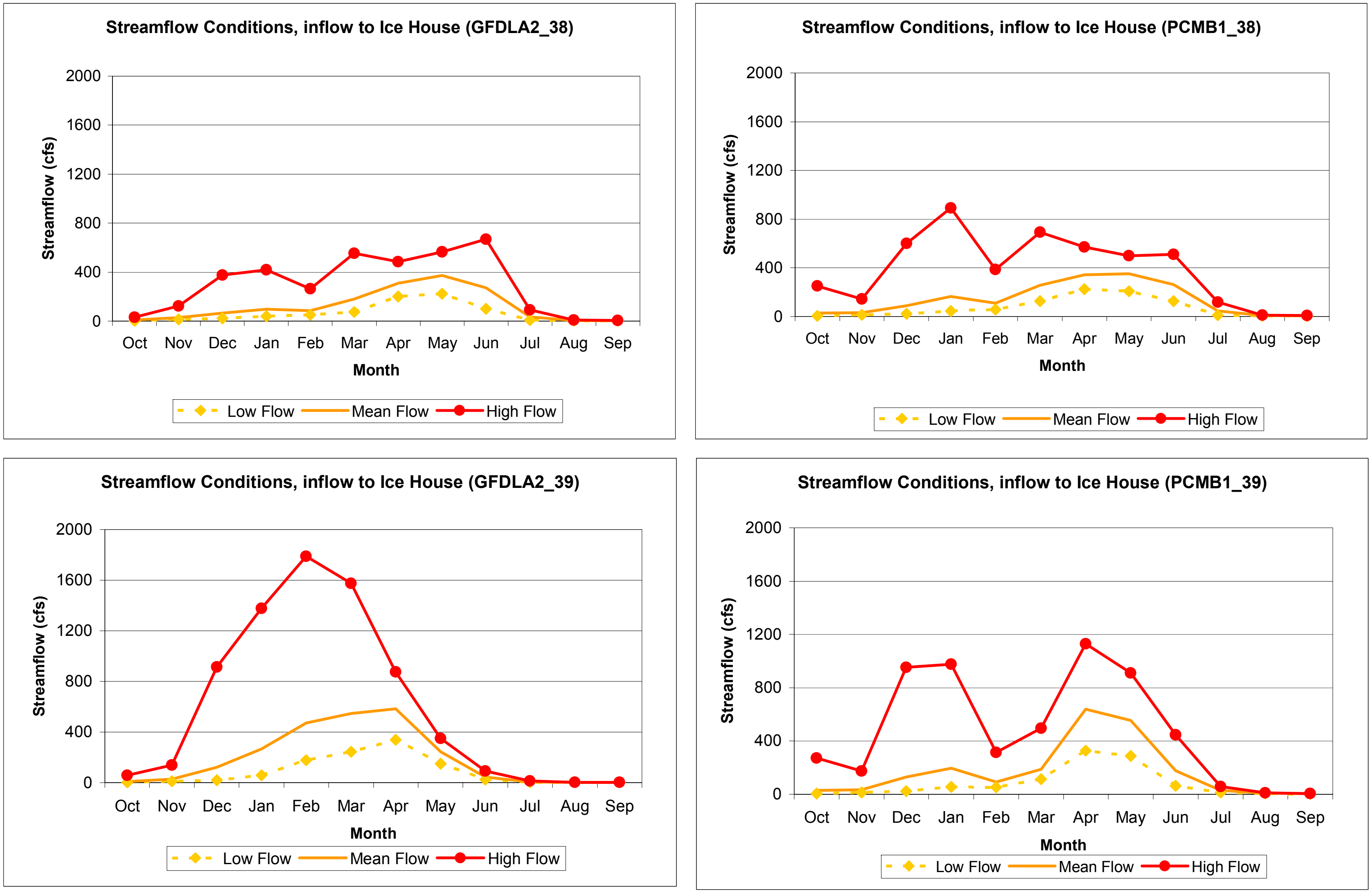


Figure 8. Streamflow conditions (unimpaired inflow to Ice House) under climate change scenarios 2070–2099

3.3. Linear Programming Model

As previously stated, the SMUD hydroelectric system in the Upper American River is composed of 11 reservoirs that can impound over 425,000 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 (see Figure 1). Several of the reservoirs in the system are small and can presumably be aggregated (according to the powerhouse into which they release water) without losing important operational components.[7] Table 1 shows the basic characteristics of the seven main components used to represent the system.

A multi-step linear optimization model was developed to represent system operations under different hydrologic scenarios. The objective of the optimization was to maximize energy generation revenues, restricted to operational constraints such as minimum instream requirements and physical constraints such as turbine or reservoir capacity. The model used monthly energy prices considered in the CALVIN[8] model formulation (see Appendix D of Lund et al. 2003).[9] System operations at 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 used energy prices as a proxy for all these factors. Future enhancements of the model will consider a revised representation of the system objectives.

In calculating energy generation, it was assumed that the head remained constant throughout the optimization. This allowed representation of the optimization problem as a linear programming (LP) problem. This assumption is reasonable where the maximum depth of a reservoir is much smaller than the head drop used to generate hydropower, and because all but two of SMUD's power plants are supplied by penstocks. Reservoir fluctuations are a very small fraction of the gross head provided by these penstocks. Table 1 shows the head of each powerhouse as compared to the maximum reservoir depth from which water is released into the powerhouse, and the powerhouse capacity. Looking at the table, it is clear that the constant-head assumption is reasonable for most of the system components except Union Valley. The capacity of that powerhouse is less than 10% of the total capacity, so one would not expect significant changes in the final results with a dynamic representation of reservoir depth.

Appendix A presents a more detailed description of the LP formulation.

A moving horizon of 12 months determined the time period over which the optimization was performed. The first of these months had 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 impacts due to differences in the relative size of flood events, crucial to the

---

7. Considering that there might be some operational oversimplifications on the Rubicon River system by doing this aggregation, future work will consider a system representation of all 11 reservoirs disaggregated.

8. CALVIN is a California-wide economic-engineering optimization model for water supply and environmental purposes developed at the University of California.

9. As explained at the end of this paper, future refinements of this work will repeat this analysis using a different set of monthly energy prices based on California Energy Commission analysis of historic values.

outcome of the system operation with regard to undesired spill. The use of an 11-month horizon in the monthly optimization avoided the need for an end storage value necessary to prevent excess releases of streamflow through the turbines, the result of myopic behavior.

It is unclear at this moment how much the "perfect foresight" condition used for the daily operations affected the operations results under different hydrologic scenarios. This issue could be explored by using a 12-month moving horizon optimization with a monthly time step at each month. The optimal releases for the first month could be used as "release targets" in a daily time step simulation model.

4.0 Results

4.1. Climate Change Hydrologic Analysis

The LP model was first run under the historic hydrologic conditions. Monthly average results from this run in terms of end-of-month storage in the whole system and energy generation pattern are shown in Figures 9 and 10. As can be seen from the results, the model is replicating the expected pattern of operations for this system, whose major features can be summarized as follows:

- To generate electricity when it's more valuable (normally summer months). This is clearly happening in this case.
- To refill reservoirs by July 1. This is also happening according to the model results.
- To leave sufficient storage in the reservoirs on October 1 to ensure a minimum summer generation during two consecutive critically dry hydrologic years (from a practical point of view this requires leaving 220 TAF (thousand acre-feet) on storage by the end of September). In this case the model is not leaving enough water in the system to prevail failure under a two-year drought condition (such as the 1976–1977 drought), which is the rationale under UARP operations for leaving 220 TAF of water in storage. However, it must be recalled that the model is using a set of hydrologic conditions that did not include such a dramatic drought and that is why it might be leaving less water as carryover storage.

Overall, the research team concludes that, although there might be specific and important differences in the way the system is operated under the LP model or under current "historic" guidelines, the model is correctly portraying the operations of this particular system in what most matters here—its monthly operational patterns.

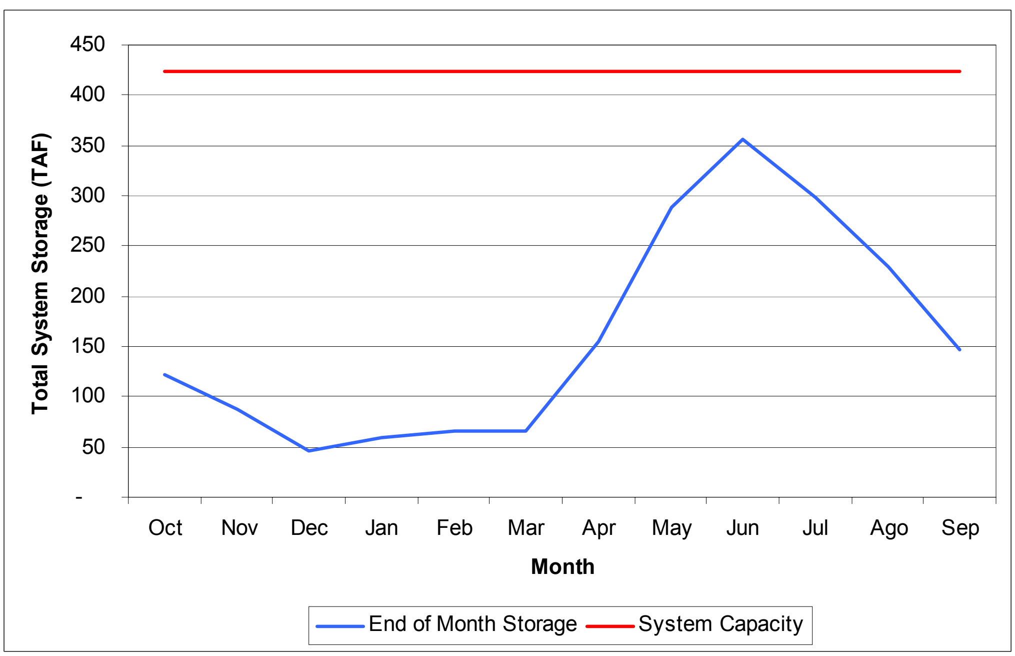


Figure 9. End-of-month storage (TAF) for the whole system, compared with system capacity

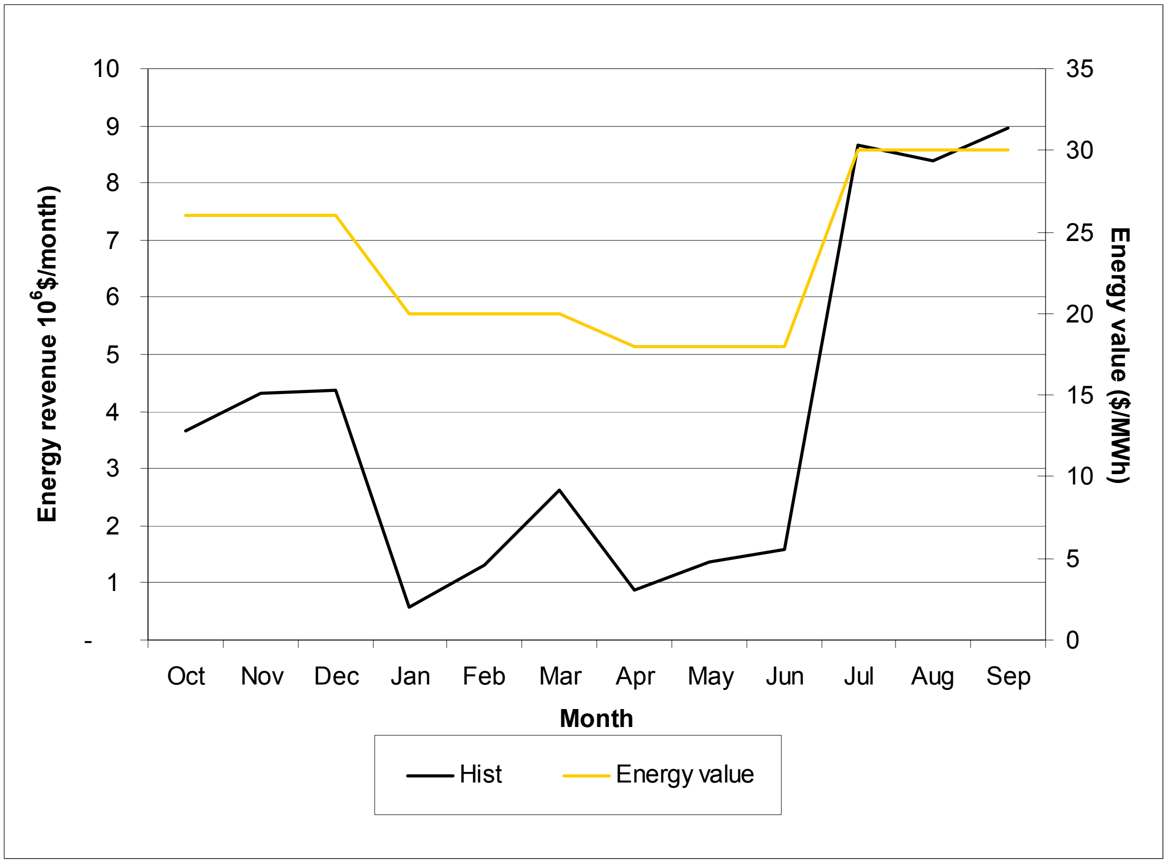


Figure 10. Energy generation: comparison of scenarios

The next step was to run the model under all four climate change hydrologic scenarios (PCMB1_38, PCMB1_39, GFDLA2_38, and GFDLA2_39). The outputs of interest were revenues from hydropower generation, monthly energy generation, and spills. The comparison between the climate change and historical scenarios is shown in Figures 11–13. Figures 11 and 12 show hydropower revenues (in nominal $ million/month) and hydroelectric energy generation (in GWh/month) for the whole system of seven powerhouses. Figure 13 shows spills in average cubic feet per second (cfs). Included in these figures for reference is the monthly energy value used in the objective function.

It can be seen that 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. However, the drop in generation (and hence revenues) during spring months is higher for the future climate scenarios than for the historical conditions. These are the months with lower energy value, so a plausible explanation for this effect is that under the climate change scenarios that predict a decrease of inflows to the system, generation is reduced in the least valuable months.

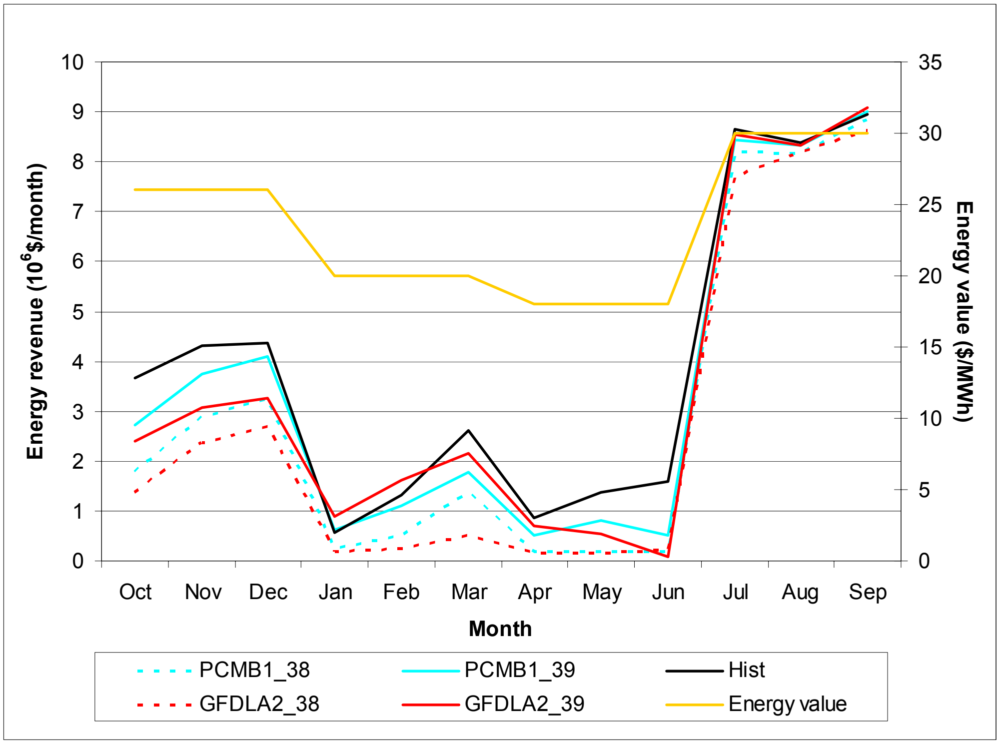


Figure 11. Energy revenues: comparison of scenarios

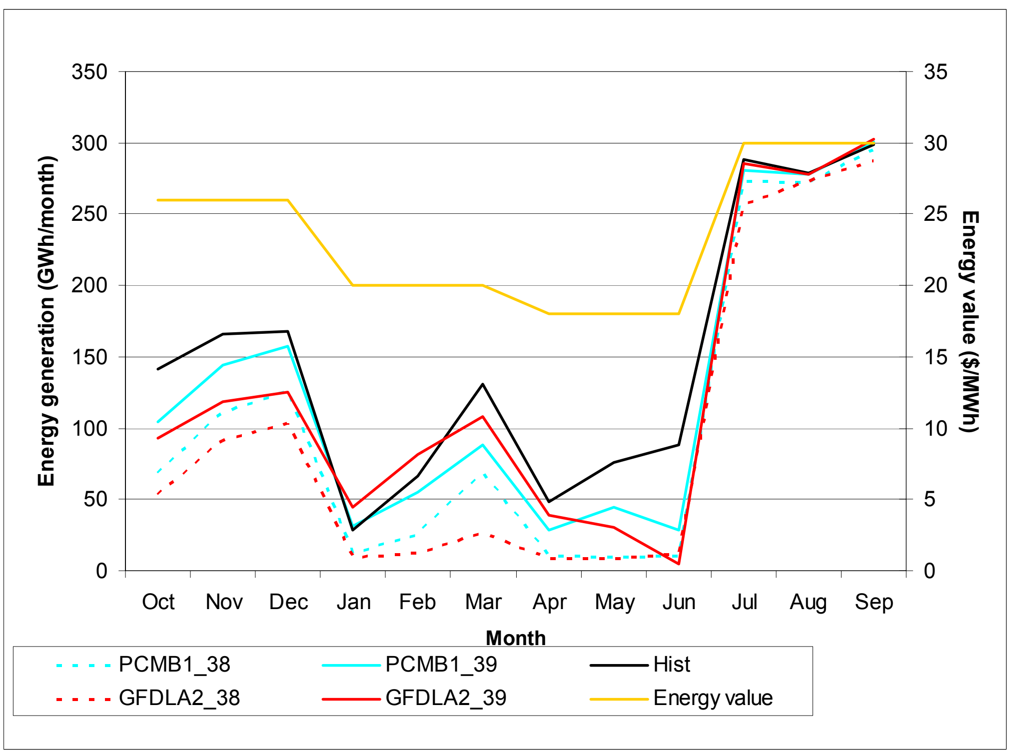


Figure 12. Energy generation: comparison of scenarios

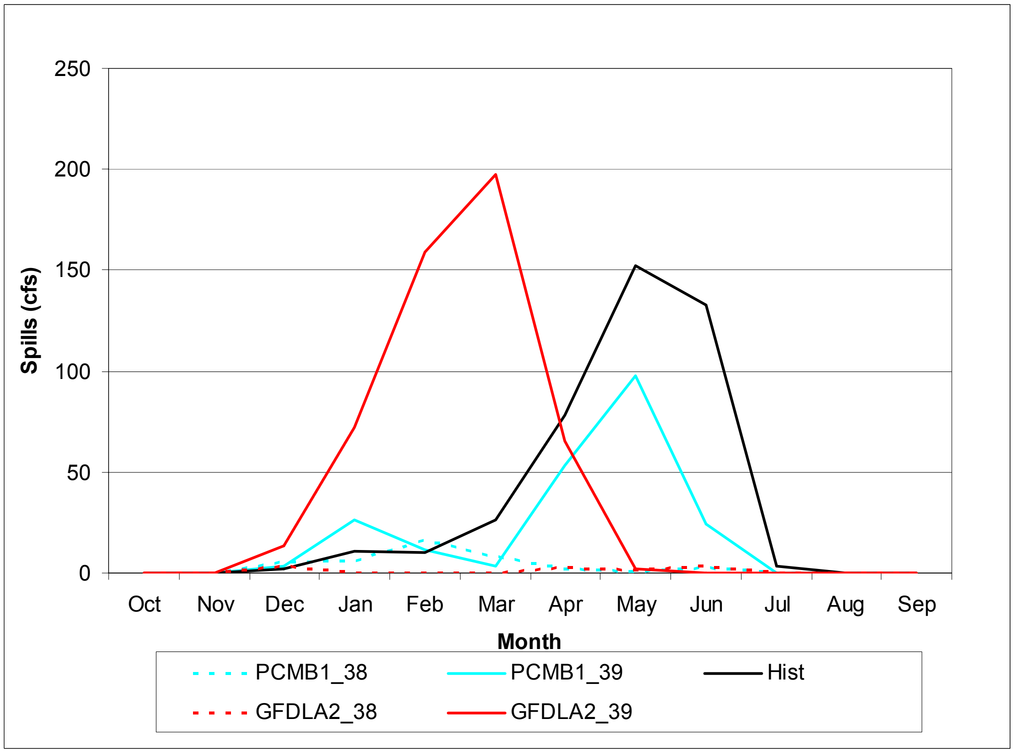


Figure 13. Spills: comparison of scenarios

The reduction in annual revenues (generation) as shown in Table 5 ranges from a 30% drop to an 11% drop. Comparing these changes with changes in annual streamflow conditions (see Table 6), it can be seen that for the most part, changes in annual streamflows are driving the changes in total generation. However, the changes in annual inflows are normally higher than the changes in generation revenues. This means that the system is able to continue moving water (in time) to more valuable months, reducing the economic effect that a drop in annual inflow might otherwise have. This ability would be expected to increase as inflows are further reduced because more storage capacity is freed up. This can be seen when comparing the relative difference between drops in revenues and drop in annual inflow (or generation) for the scenarios analyzed. For example, scenario PCMB1_38 had a drop of 29% in inflows but only 23% in revenues, while scenario PCMB1_39 had a drop of 38% in inflows but only 30% in revenues.

Another interesting finding is that the change in timing of inflows has a smaller-than-expected negative impact on hydropower generation in this system. Comparison of the PCMB1_39 and GFDLA2_39 scenarios, for example, shows that even though both systems have comparable drops in annual inflow, the latter has a larger drop in generation revenues than the former. However, the differences are smaller than expected considering that scenario GFDLA_39 has a larger shift in monthly timing of inflows and a greater shift in time of occurrence and magnitude of high inflows to the system than does scenario PCMB1_39. It would have been expected that GFDLA2_39 would have spilled significantly more than PCMB1_39 and hence lost the opportunity to generate in the high-value months of summer.

Table 5. Change in annual output from the system (as absolute value and percent of historical output; average of historic and perturbed 1928–1949 period)

	Generation				Average Monthly Spills (cfs)
	10^6 dollar/year		GWh/year		
Historical	46.6		1,778		35
PCMB1_38	35.8	77%	1,282	72%	3
PCMB1_39	41.7	89%	1,542	87%	18
GFDLA2_38	32.5	70%	1,143	64%	1
GFDLA2_39	40.7	87%	1,510	85%	42

Table 6. Comparison between changes in hydropower generation and in annual inflows to the system (as a percent of historical output; average of historic and perturbed 1928–1949 period)

	Change in Generation		Change in Annual Streamflow
	10^6 dollar/year	GWh/year	
PCMB1_38	77%	72%	71%
PCMB1_39	89%	87%	86%
GFDLA2_38	70%	64%	62%
GFDLA2_39	87%	85%	86%

The same conclusion is reached when comparing the average spills from all scenarios, as presented in Figure 13. A closer look at Figures 13 and 14 tells a different story, though. Figure 14 shows the locations and timing of spills. In Figure 14, the main system component that is spilling under both the historical and GFDLA2_39 climate change scenarios is Ice House Reservoir (component 4), although it does so in different months. Table 1 indicates that Ice House Reservoir has a large relative storage capacity, and it serves as the sole supplier of water by penstock to the 20-MW Jones Fork PH. However, spills from Ice House Reservoir are captured downstream at Junction Reservoir (below Union Valley). What is happening here is the following: Forced by a constraint in penstock capacity leading to the Jones Fork Powerhouse, system managers will spill at Ice House Reservoir and recapture flows at downstream reservoirs that have more generation capacity.

This and other constraints might be strong enough to limit the operation of the system regardless of the hydrologic conditions under which is operating. In order to study the effects these constraints have on the ability of the system to confront changes in the timing and total amount of inflow, the project analyzed the sensitivity of the results to changes in some of the most relevant system parameters.

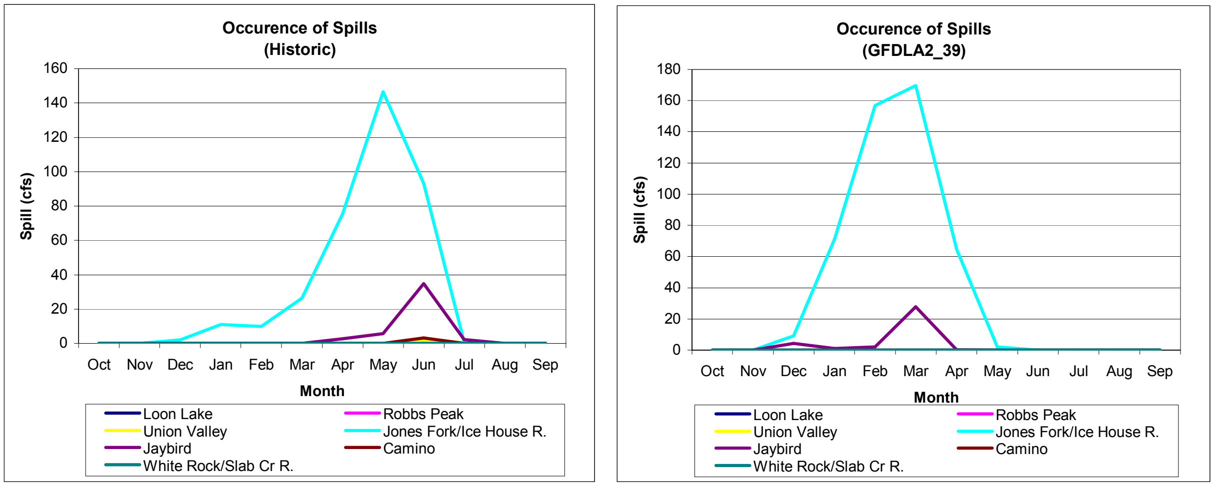


Figure 14. Spills for different components of the SMUD system

4.2. Sensitivity Analysis

The operation of a hydropower generation system depends not only on the hydrologic conditions of the basin but also on the characteristics of the infrastructure such as reservoir, powerhouse, and conveyance capacities. In order to explore how these different components might affect results under climate change–induced hydrologic conditions and potentially extract information that can be applied to different systems, a sensitivity analysis was performed on some model parameters representing the system's infrastructure.

Following the discussion at the end of the previous section, the first parameter investigated was the penstock/generation capacity of Ice House Reservoir/Jones Fork Powerhouse. The results for both the historical and climate change conditions show that spills were occurring at this powerhouse not because of constraints in the reservoir capacity but rather because of constraints in the generation capacity. Figures 15 and 16 and Table 7 show the results for a run in which the penstock flow capacity and powerhouse generation were both increased by a factor of five. The result of reducing this constraint is a reduction in spills from the Ice House Reservoir, as expected from the previous analysis. Results in terms of generation revenues are similar to the original case without the change in parameter, which could imply that the water spilled in the first case generated energy using idle capacity in downstream reservoirs. This result speaks to the ability of a highly interconnected system to deal with constraints and changes that might occur in isolated portions of it.

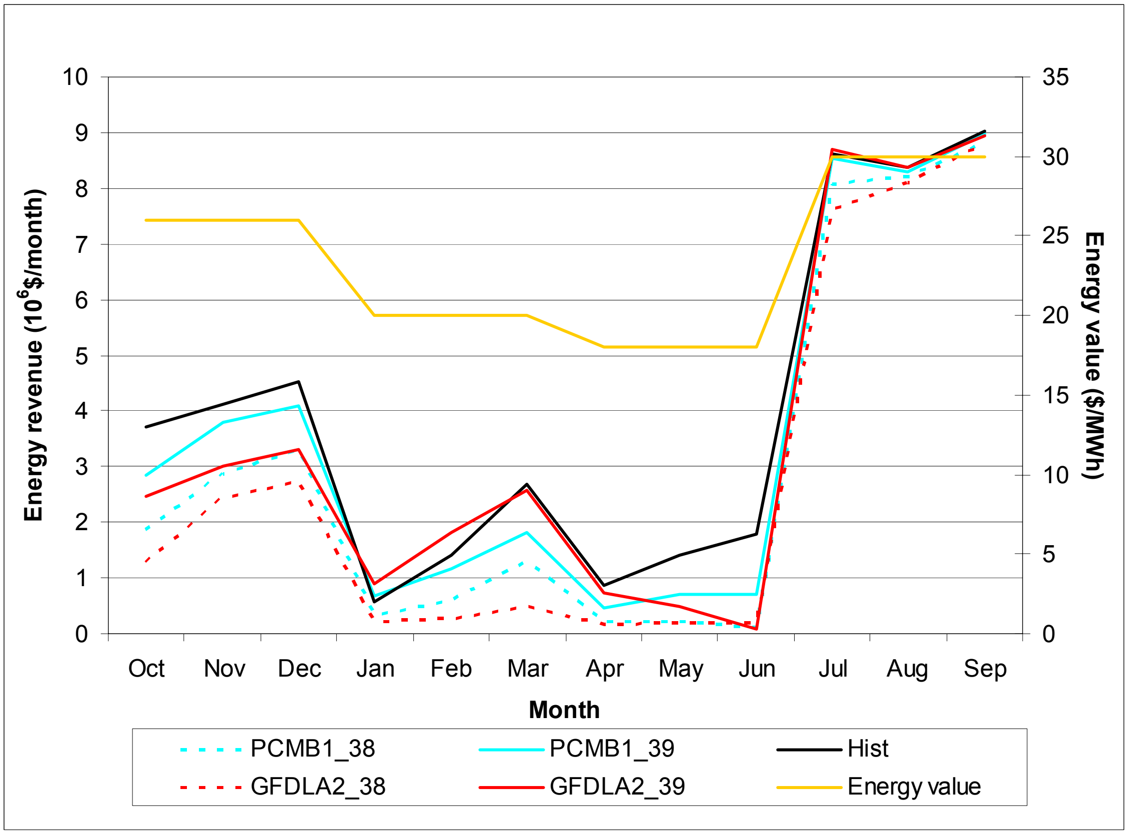


Figure 15. Energy revenues: increased penstock/generation capacity at Jones Fork/Ice House

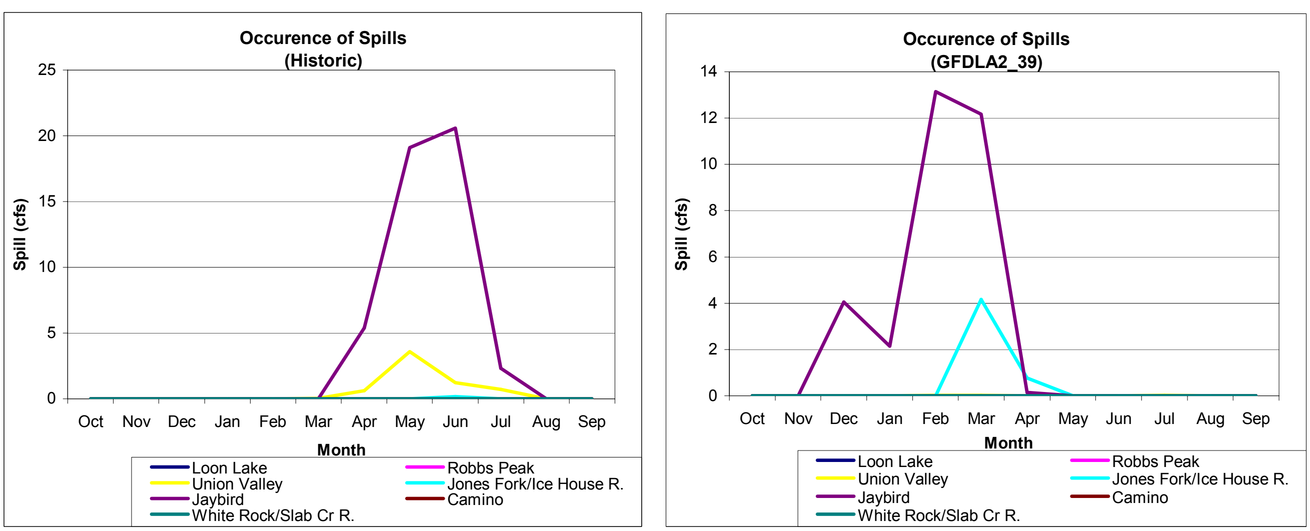


Figure 16. Spills for different components of the SMUD system with five-fold increased penstock and generation capacity at Ice House Reservoir and Jones Fork PH

Table 7. Change in annual output from the system (as absolute value and as a percent of historical output) with increased penstock capacity at Jones Fork/Ice House

	Generation				Average monthly Spills (cfs)
	10^6 dollar/year		GWh/year		
Historical	47.1		1,800		4
PCMB1_38	35.9	76%	1,286	71%	0
PCMB1_39	42.0	89%	1,556	86%	1
GFDLA2_38	32.5	69%	1,143	63%	0
GFDLA2_39	41.3	88%	1,540	86%	3

Another parameter explored in this analysis was the effect of storage capacity on the ability of a high-elevation hydropower system to deal with changes in hydrologic conditions. In the case of SMUD's Upper American River Project, the hydropower system is composed of a complex set of 11 interrelated reservoirs with a storage capacity of more than 400,000 ac-ft, a value that represents almost 80% of average annual inflows into the system (this includes inflows to Union Valley and Ice House Reservoirs and inflows from the Rubicon River and South Fork American River). How would a different system with a different storage capacity behave under the same hydrologic scenarios?

Such effects were examined by running two more scenarios, one in which all reservoirs in the system were doubled in size and one in which all reservoirs were reduced to a fourth of their size. The results of these two scenarios are shown in Figures 17–19 and Table 8. In terms of GWh of electricity generated and associated revenues, the results show, as expected, that doubling the size of reservoirs increases generation and that reducing them to a fourth of their size decreases generation. Generation patterns under a doubling of the reservoir size more closely match the pattern of energy value, i.e., the system increases generation during the months of fall and early winter as compared with the original case (compare Figures 11 and 17). On the other hand, the generation pattern under a reduced storage capacity scenario more closely reflects the hydrograph pattern, with an increase in late winter and spring generation/revenues as compared with the original case (compare Figures 10, 11, and 18). Pushing this to an extreme of no storage capacity reaches a scenario under which generation happens in the exact same pattern as the inflow pattern. This reflects the benefits of storing water and moving streamflow in time from a less valuable month to a more valuable month.

Table 8. Changes in annual output from the system (as absolute value and as a percent compared to historical output) for a doubling and a quartering of system storage capacity

Climate Scenario	Doubled Generation 10^6 dollar/year		Doubled Generation GWh/year		Average Monthly Spills (cfs)	Quartered Generation 10^6 dollar/year		Quartered Generation GWh/year		Average Monthly Spills (cfs)
Historical	49.1		1,835		5	35.9		1,605		226
PCMB1_38	37.5	76%	1,326	72%	0	29.3	82%	1,255	78%	31
PCMB1_39	43.8	89%	1,594	87%	0	32.5	91%	1,435	89%	127
GFDLA2_38	34.0	69%	1,185	65%	0	26.1	73%	1,110	69%	28
GFDLA2_39	42.8	87%	1,568	85%	18	32.0	89%	1,398	87%	172

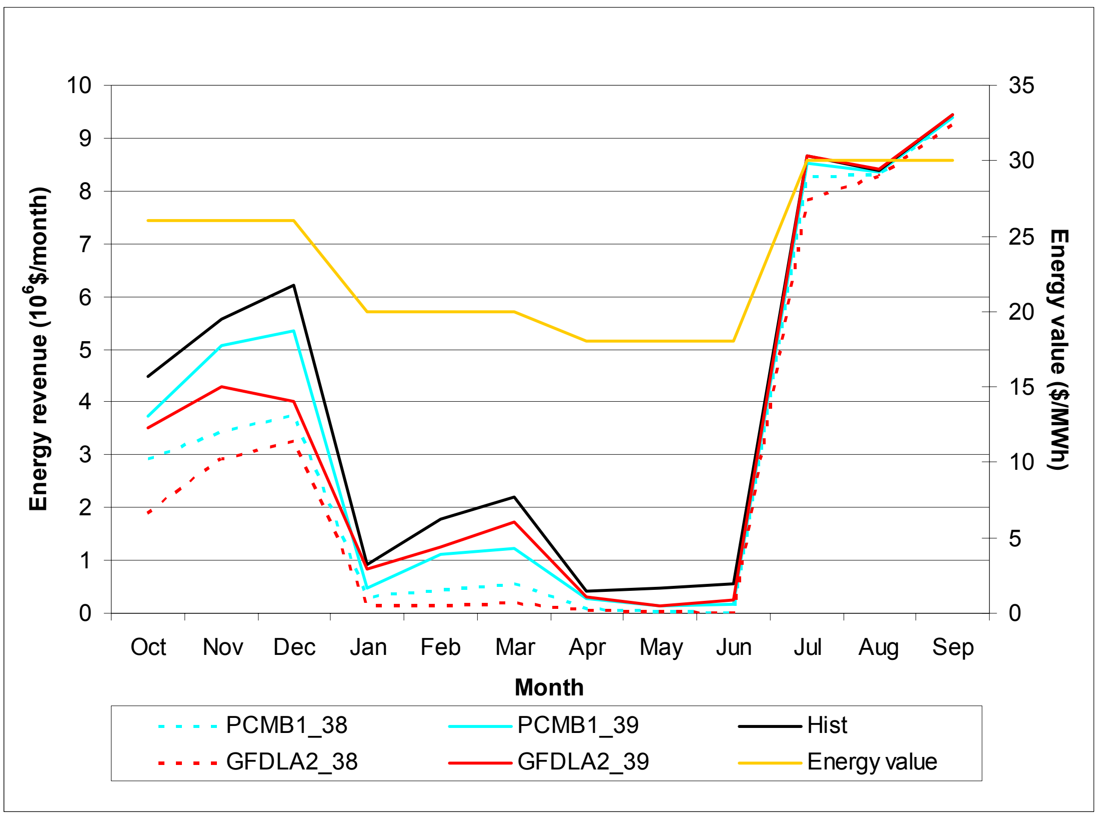


Figure 17. Energy revenues: doubling reservoir capacity

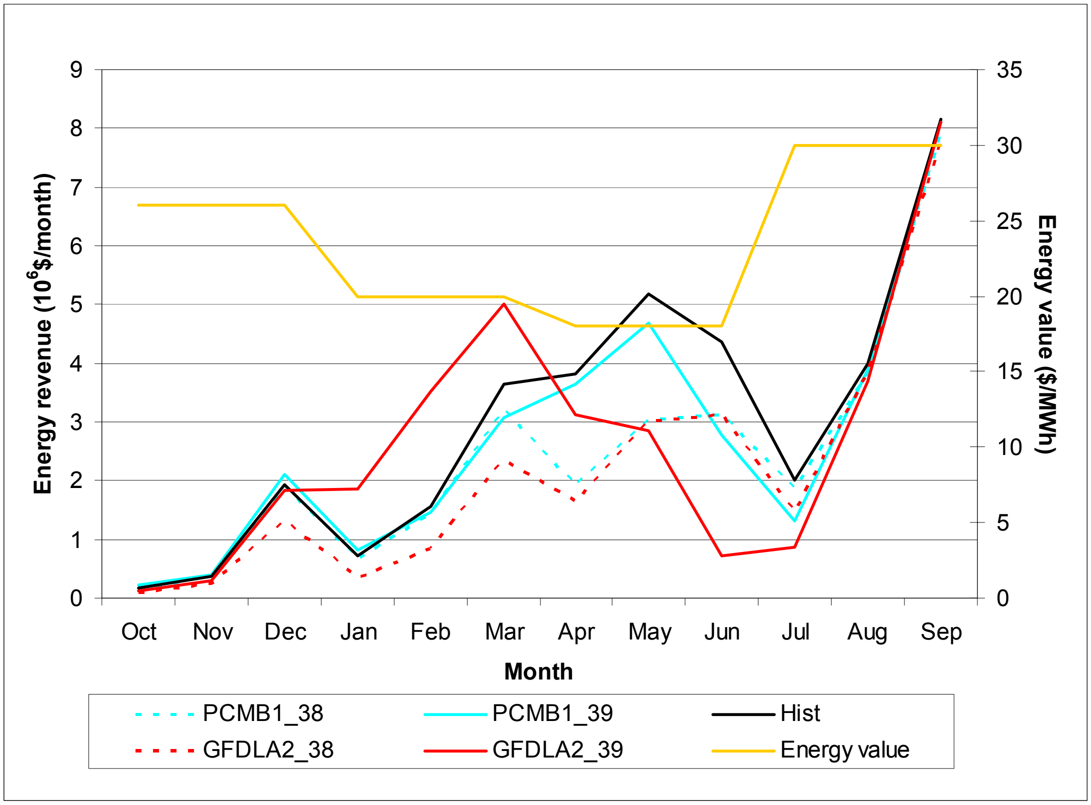


Figure 18. Energy revenues: quartering reservoir capacity

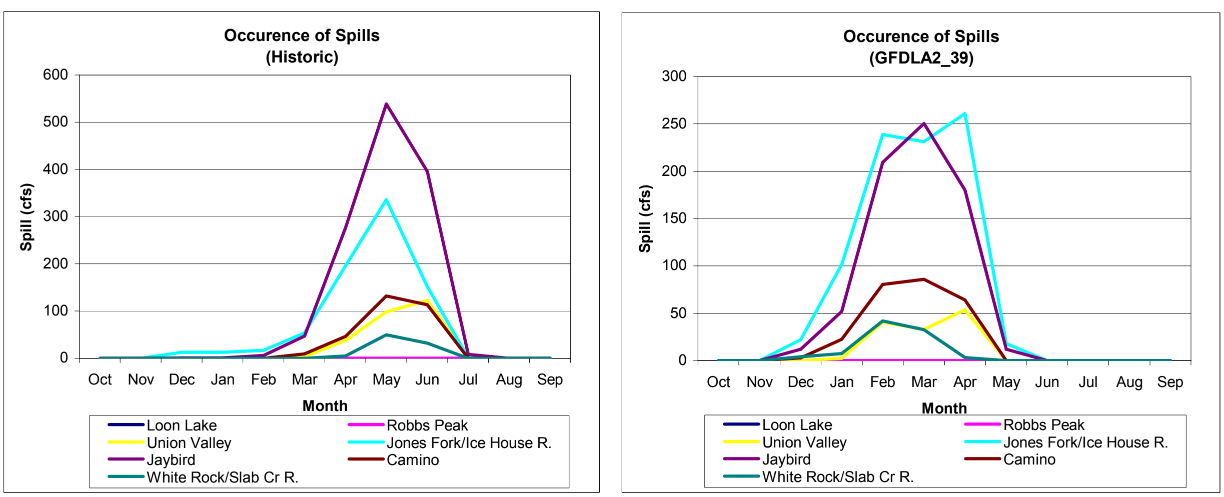


Figure 19. Spills for different components of the SMUD system: a quartering of reservoir capacity

In terms of the amount of spills, the results are as expected, i.e., they decrease under the doubling scenario and increase under the reduced-storage scenario. When looking at the components of the system most prone to spills (Figure 19) for the quartering scenario, it is apparent that spills mostly happen to reservoirs which have downstream reservoirs capable of using the spilled water to generate if they have idle generation capacity. (Only those spills happening on Robbs Peak and White Rock/Slab Creek developments exit the interconnected system.)

There is not yet a large disparity in the impacts due to different climate change scenarios that can't be explained mainly by changes in annual streamflow conditions. That is, even under very stressed conditions in terms of reduced storage capacity, there is no clear effect of changing the timing of inflows or of having a different pattern of high-flow events. One last set of scenarios was run to explore why results do not indicate the expected change in impacts associated with the change in timing of streamflows.

The two last scenarios slightly changed the pattern of energy prices. As can be seen from Figures 11, 12, 17, and 18, the pattern of energy prices 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. The two new scenarios considered both the doubled and quartered storage capacity conditions but with the energy price in June raised from $18/MWh to $30/MWh. Results from these new scenarios are shown in Table 9 and Figures 20 and 21. The different pattern is quite notable.

Looking at the case where the reservoir capacities are doubled, it is apparent that the system makes use of that extra capacity to store more for generating in June. The pattern of generation closely resembles the pattern in energy prices as seen already in the previous set of runs. It is in the case where the storage capacity is significantly reduced where results finally indicate a higher relative impact for those climate scenarios that show the greatest change in streamflow timing. Focusing again on the PCMA1_39 and GFDLA2_39 cases, these two scenarios—as can be recalled from Table 3—have similar reductions in terms of annual inflows but a different pattern in hydrograph conditions (GFDLA2_39 has a much earlier timing of inflows). Now the change (drop) in energy generation revenues under GFDLA2_39 is much higher than the drop under PCMA1_39. This is the first case showing an impact on energy value that is greater than the impact on energy generation. The reasons for this are evident when comparing the streamflow conditions under these two climate change scenarios. In Figures 7 and 8, the June unimpaired flow is almost nonexistent under GFDLA_2 but there is still some flow left under PCMA1_39. The reduced storage capacity did not allow the system to store that water under GFDLA_2 and it had to generate during the less-valuable winter and spring, following the timing of inflow.

Table 9. Changes in annual output from the system (as asolute value and as a percent of historical output) for the scenarios with doubling and quartering of system storage capacity and modified June energy price (from $18 to $30 per MWh)

Climate Scenario	Doubled Generation 10^6 dollar/year		GWh/year		Average Spills (cfs)	Quartered Generation 10^6 dollar/year		GWh/year		Average Spills (cfs)
Historical	51.2		1,842		5	38.9		1,601		231
PCMB1_38	38.9	76%	1,342	73%	0	31.5	81%	1,253	78%	33
PCMB1_39	45.2	88%	1,591	86%	0	34.4	89%	1,434	90%	127
GFDLA2_38	35.1	69%	1,196	65%	0	28.2	73%	1,105	69%	30
GFDLA2_39	44.5	87%	1,583	86%	18	32.4	83%	1,397	87%	172

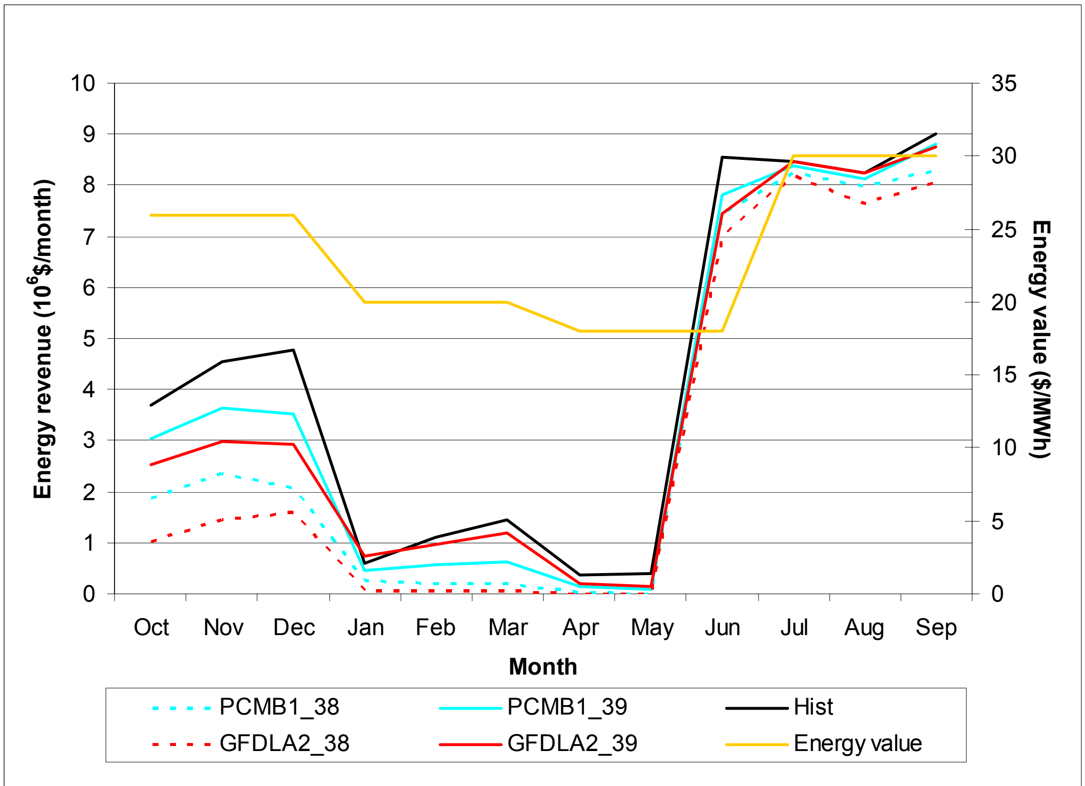


Figure 20. Energy revenues: doubled reservoir capacity and increased energy value in June

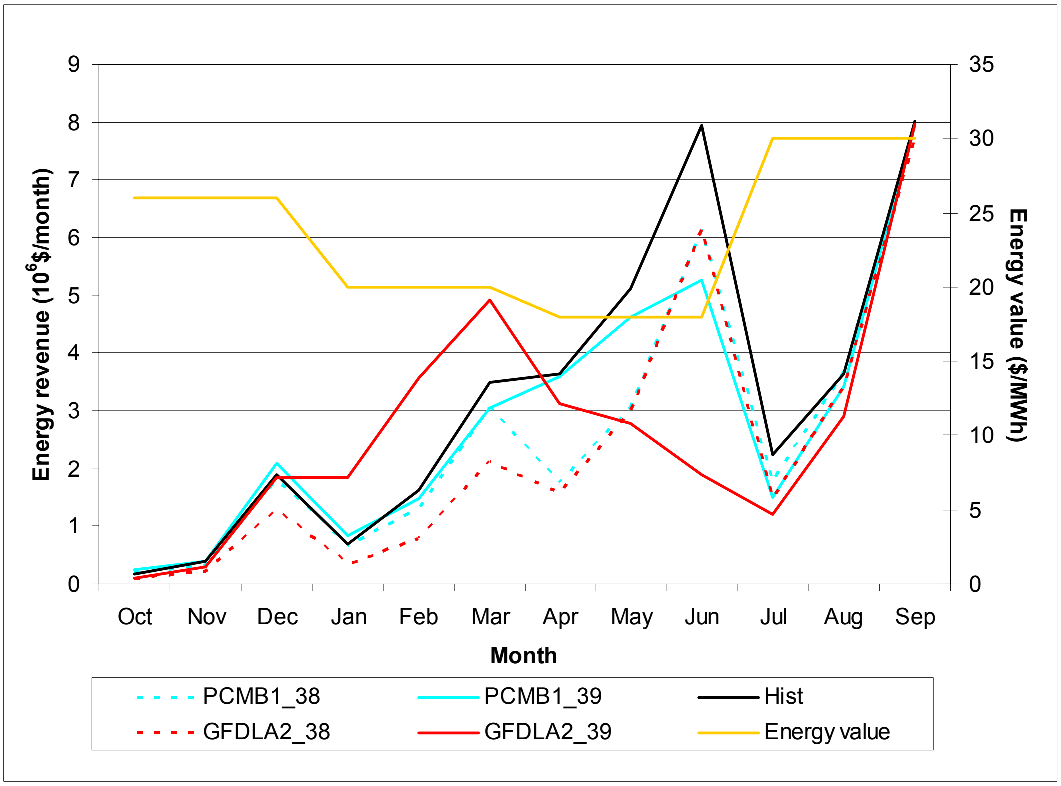


Figure 21. Energy revenues: a quarter of reservoir capacity and increased energy value in June

5.0 Conclusions

In an effort to understand the possible impacts of climate change on high-elevation hydropower generation in California, this study developed a linear programming model of a simplified representation of the 11-reservoir hydroelectric system operated by the Sacramento Municipal Utility District in the Upper American River Project. Hydrologic conditions under climate change scenarios were developed from hydrologic results predicted for nearby locations by the Variable Infiltration Capacity model run using climatic output from two GCMs under two emissions scenarios.

The results showed that hydropower generation, in terms of energy generated and revenues, drops under all climate change conditions as a consequence of drier hydrologic conditions. The drop was 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 was no clear effect in terms of different relative impacts associated with either changes in the timing of inflows or the magnitude and occurrence of high flows. It was expected that a hydrograph with inflows far from the high-value months in summer would have led to lower energy revenues. Similarly, it was expected that a scenario with greater flood events in winter would have led to increases in spills during the winter months and hence losses of stored water to be used during the high-value months.

In order to understand why these assumptions were wrong in first place, a sensitivity analysis was conducted for different aspects of the system. One of the parameters investigated was overall system storage capacity. Changing this parameter, "doubled" and "quartering" capacity runs were performed. These runs showed that under increased storage capacity, energy generation revenues closely match energy prices, while under reduced storage capacity, energy generation revenues match streamflow conditions. However, results did not show a different relative impact from the different timing conditions associated with the climate change conditions.

It was only when the energy price for the month of June was changed through a last set of runs that model results showed the expected timing effect. The reason for this is as follows: The original model run had a very low energy price in June ($18/MWh) as compared with the energy prices in July through September ($30/MWh). The historical streamflow scenario does not have significant unimpaired inflows in the summer months from July through September (the last month with significant inflows being June), so a change in timing associated with the climate change scenarios is not going to affect the conditions in these high-value months (reducing a very low flow will still be very low). Thus a change in peak runoff from May to April does not affect system operations. When the June energy price was increased, the change in timing *did* have an effect on total revenues from this system.

Another issue illuminated by this sensitivity analysis is that the system as modeled in this project can handle high-flow events, minimizing the amount of water spilled without passing through the turbines. Two major factors contribute to this ability to handle high-flow events:

First, the reservoir interconnections in this system allowed the use of water spilled in one reservoir (that had reached some capacity constraint) to generate in the same month using a reservoir downstream with idle capacity (there are obviously opportunity costs associated with this spilled water, but they are lower than if the water went outside the system).

The second factor is the approach used to formulate the LP problem, which assumed that the system will perfectly accommodate the predicted changes in inflow patterns. If the hydrologic pattern were to change dramatically, one would expect impacts larger than those suggested here, because the system would be operated for a certain period using the same "rules" it had followed under the historical conditions. Another problem is associated with the perfect foresight the system was assumed to have in terms of daily streamflow conditions within a month horizon. This level of perfect foresight helped the operation of the system to accommodate the advent of high-flood events in a rather unrealistic way.

Based on results of this project, it is expected that hydroelectric systems located in basins with significant inflows close to summer months will be affected by the timing effects associated with 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. There is still more work to be done to fully 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 system operators and will be included in future refinements of the model used in this effort.

6.0 Future Work

Recognizing some of the limitations of this paper, future work will modify the analysis conducted here to incorporate the following improvements:

- **Perfect foresight**. In order to better assess the implications of different pattern of high-flow events, the model used in this project will be refined to include a smaller time horizon for the daily optimization (5–7 days) that will better reflect the uncertainties associated with flood events and will better capture their associated impacts under a climate change scenario. A statistical analysis will also be performed to better define high-flow events into the SMUD system.
- **System representation.** In order to have a better sense of operational constraints in the SMUD hydroelectric system, future work will disaggregate the three-reservoir system that is fed by the Rubicon River (i.e., Rubicon, Buck Island, and Loon Lake Reservoirs).
- **System objectives and energy prices.** System operations as simulated by the LP model are driven by monthly average energy prices. The UARP system, like other high-elevation hydropower systems, does not operate with the sole objective of electricity revenues; other objectives include peaking, real-time load following, and river and reservoir management. To more closely simulate real system operations, the model's objective function will be modified in an attempt to better include this array of objectives. A first step will involve differentiating on- and off-peak energy prices on a daily, weekly, and monthly basis (Tejada-Guibert et al. 1990). In order to obtain a representative set of energy values, historic energy prices and historic load duration curves will be analyzed for the different powerhouses in the system.

7.0 References

Aspen Environmental and M-Cubed. 2005. Potential changes in hydropower production from global climate change in California and the western United States. Prepared in support of the 2005 Integrated Energy Policy Report Proceeding. California Energy Commission, Sacramento, CA.

Cayan, D., E. Maurer, M. Dettinger, M. Tyree, K. Hayhoe, C. Bonfils, P. Duffy, and B. Santer. 2006. Climate Scenarios for California. Public Interest Energy Research, California Energy Commission. CEC-500-2005-203-SF.

Lund, J. R., R. E. Howitt, M. W. Jenkins,T. Zhu, S. K. Tanaka, M. Pulido, M. Tauber, R. Ritzema, and I. Ferriera, I. 2003. Climate Warming & California's Water Future: Appendix D, Hydropower Demands. Center for Environmental and Water Resource Engineering. University of California, Davis. CA. California Energy Commission, Sacramento, CA. Available at http://cee.engr.ucdavis.edu/faculty/lund/CALVIN/ReportCEC.

SMUD. 2001. The Upper American River Project Initial Information Package (IIP). *FERC Project No. 2101.* Sacramento Municipal Utility District, Sacramento, CA. Available at http://hydrorelicensing.smud.org.

Tejada-Guibert, A., J. R. Stedinger, and K. Staschus. 1990. Optimization of the Value of CVP's Hydropower Production Within Contractual Constraints. *Journal of Water Resource Planning and Management,* 116 (1): 52–70.

8.0 Glossary

A2	A future emissions scenario with relatively high greenhouse gas emissions as detailed in the Special Report on Emissions Scenarios by the Intergovernmental Panel on Climate Change
B1	A future emissions scenario with relatively low greenhouse gas emissions as detailed in the Special Report on Emissions Scenarios by the Intergovernmental Panel on Climate Change
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
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

The LP formulation for this problem is the following:

$$\underset{\mathrm{Rel}_i^d,\mathrm{Rel}_i^m}{Max}\left(\sum_{d=1}^{dmonth}\sum_{i=1}^{nres} Energy_i^d * c^t + \sum_{m=1}^{nmonth}\sum_{i=1}^{nres} Energy_i^m * c^m\right)$$

s.t.

$$Energy_i^d = 24 * Power_i^d$$
$$Energy_i^m = 24 * 30 * Power_i^m$$

$$Power_i^d = \min\left[\mathrm{RelUnits_i^d} * H_i * 9.8 * eff_i, MaxPower_i\right]$$
$$Power_i^m = \min\left[\mathrm{RelUnits_i^m} * H_i * 9.8 * eff_i, MaxPower_i\right]$$

$$\mathrm{Res}_i^n + \text{Inflow+SpillsAbove+ReleaseAbove-Spills-Releases-Outputs} = \mathrm{Res}_i^{n+1}$$

(some reservoirs receive spills and releases from upstream reservoir, some don't)

$$0 \le \mathrm{Res}_i^n \le \mathrm{CapRes}_i$$
$$0 \le \mathrm{RelUnits}_i^n \le \mathrm{CapRel}_i$$
$$\mathrm{SpillMin}_i^n \le \mathrm{SpillUnits}_i^n \le \mathrm{CapSpill}_i$$

where,

Res_i^n is reservoir i storage in period n with a maximum of CapRes_i

$\mathrm{RelUnits}_i^n$ are releases through penstock from reservoir i in period n (in m^3/s). These are constrained by CapRel_i

$\mathrm{SpillUnits}_i^n$ are releases from reservoir I not passing through penstock (this could be spills, intentional in stream releases or minimum instream flow requirement releases - $\mathrm{SpillMin}_i^n$). These releases are constrained to be smaller than $\mathrm{CapSpill}_i$