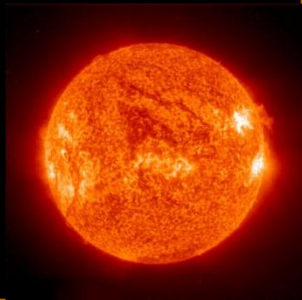
Climate Change: Implications for Reservoir Management and Hydroelectricity in California

*Kaveh Madani**
Jay Lund

*kmadani@ucdavis.edu

Dept. of Civil and Environmental Engineering
University of California, Davis

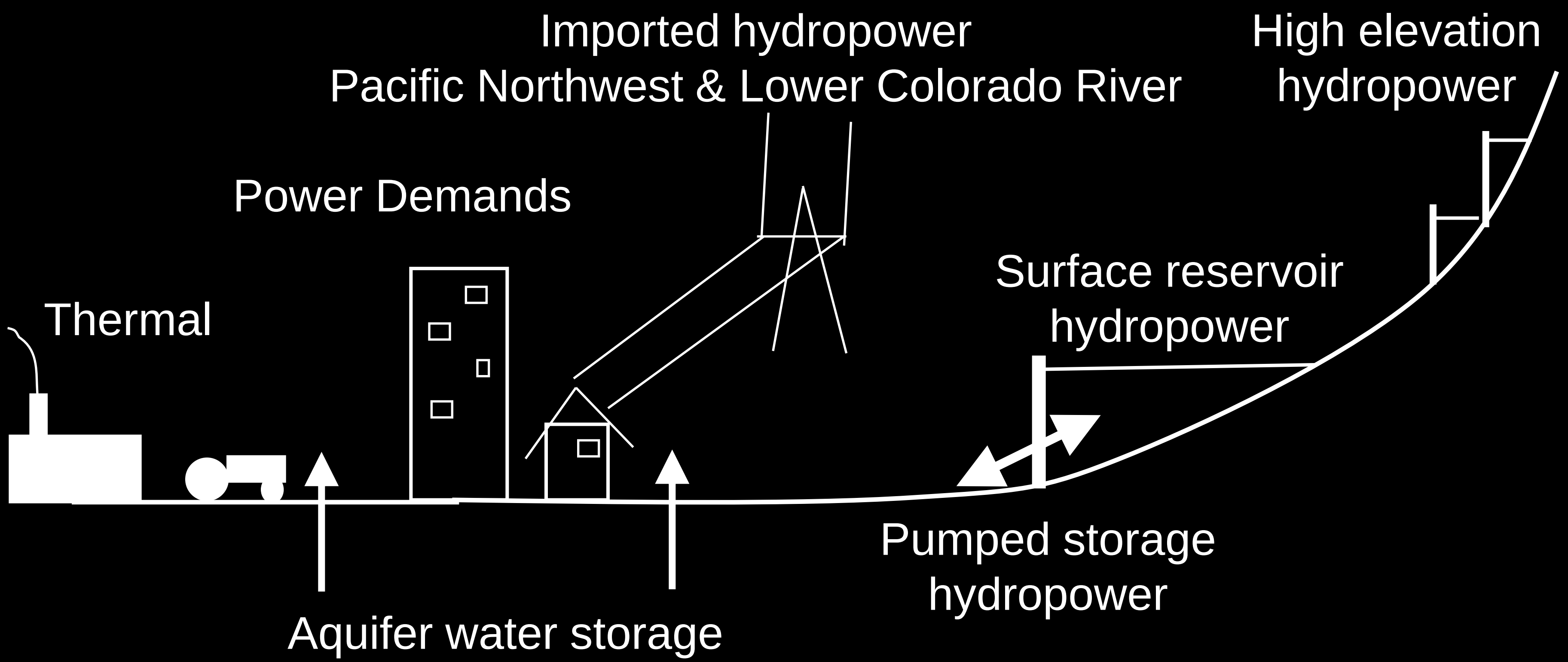
March 2009



Outline

- Hydropower in California
- Effects on Low Elevation System (CALVIN)
- Effects on High Elevation System (EBHOM)
- Results
- Limitations!
- Next Step?
- Conclusions

Hydropower Systems



Hydropower and California

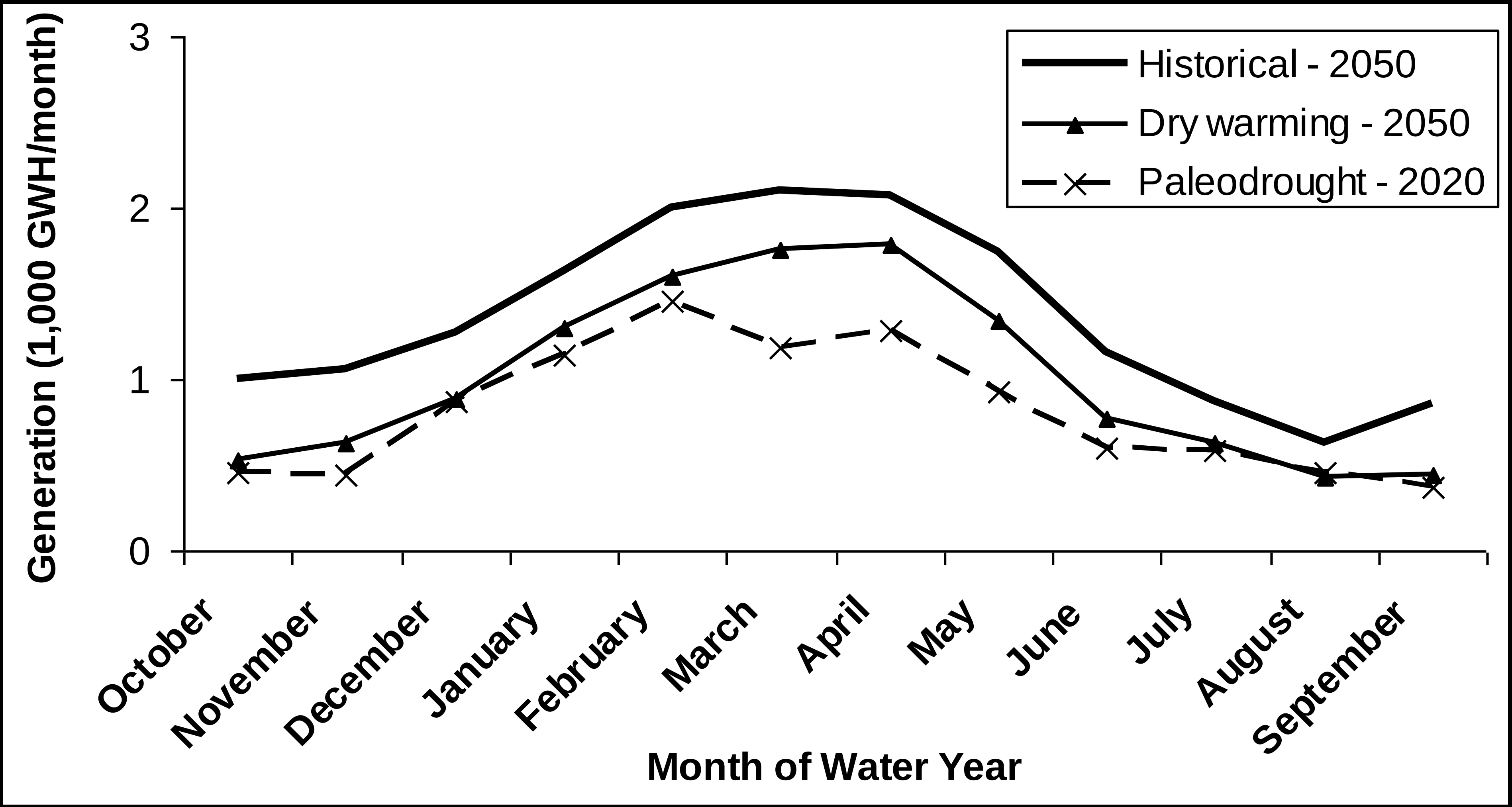
	1,000 GWH/yr, 2004
Hydropower Total	45.4
In-state Hydropower	*34.4*
High Elevation*	25.3
Low Elevation*	9.1
Pumped Storage	?
Imported Hydropower	*11*
PNW	9.5
LCR	1.5
Thermal	205.2
Other renewables	24.5
Total	**275.1**

* Estimated   Sources: CEC; McCann 2005

Climate Effects on Hydropower

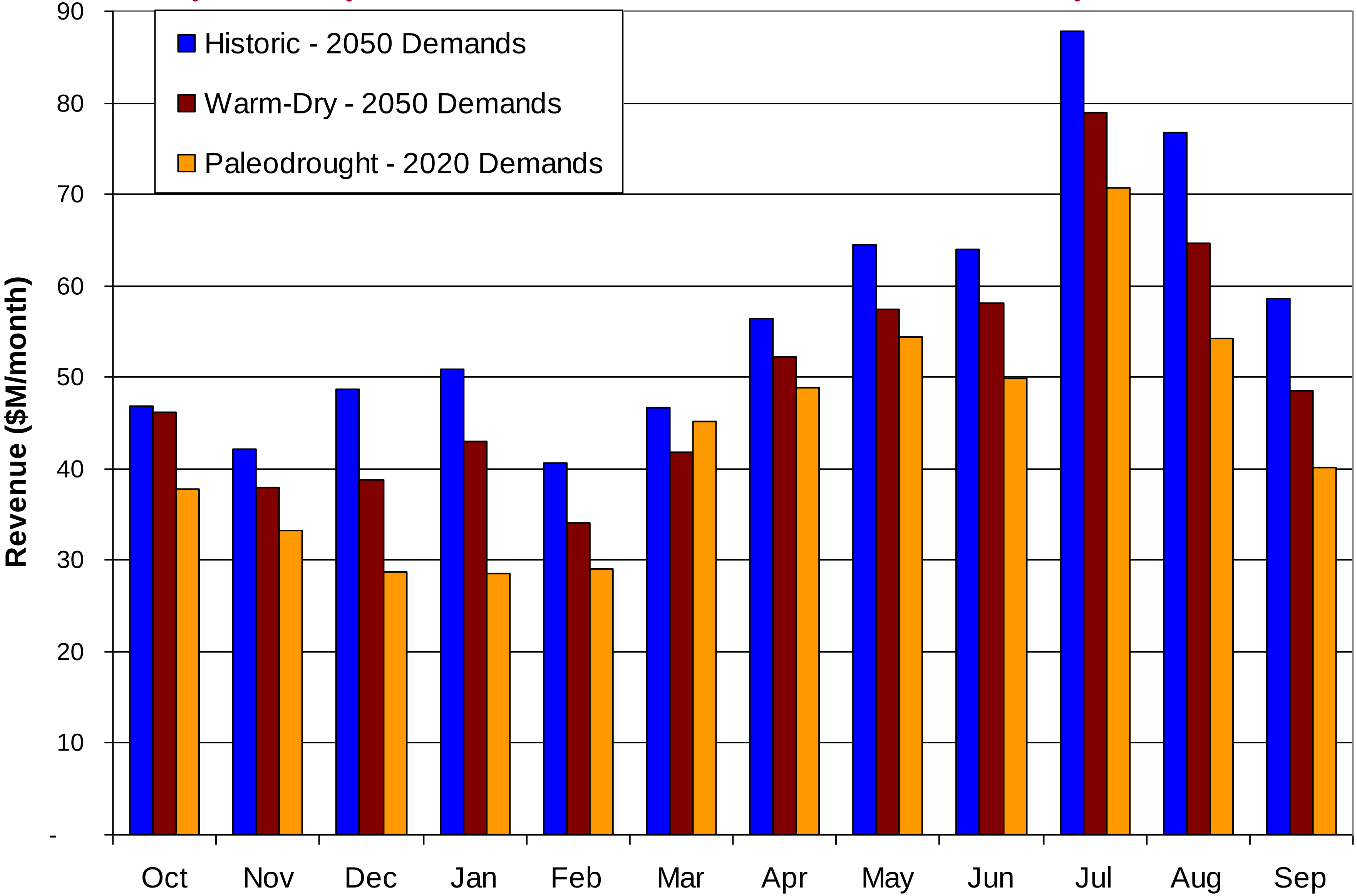
1. Energy demand
2. Timing of water availability
3. Quantity of water available
4. Availability of hydropower to import
5. Thermal generation efficiency
6. Sensitivity of environment to hydro operations

Water Supply Dam Hydropower Seasonal Generation Changes

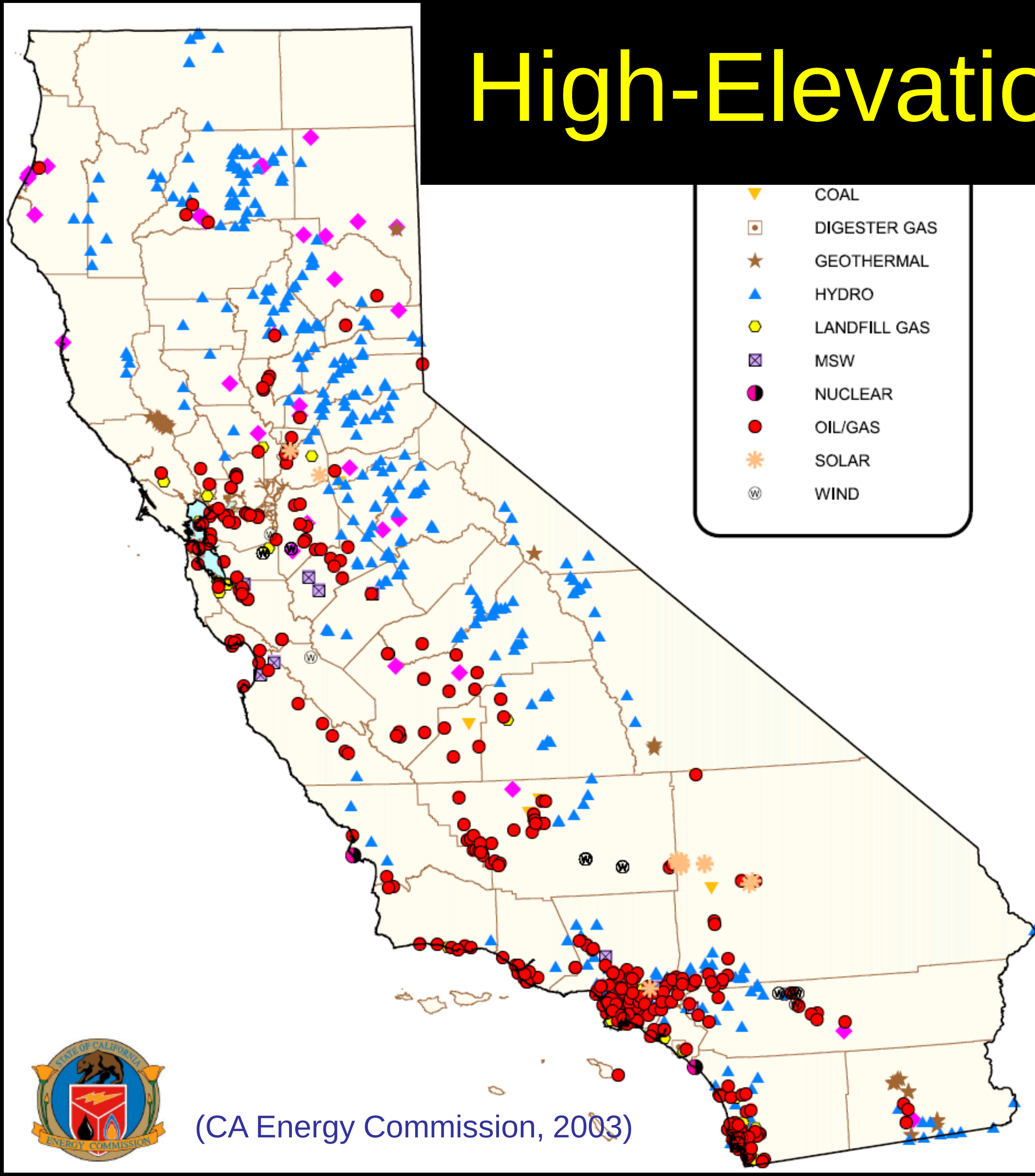


Major water supply reservoirs in CALVIN system optimization model

Average Water Supply Reservoir Hydropower Benefits ($M/year)

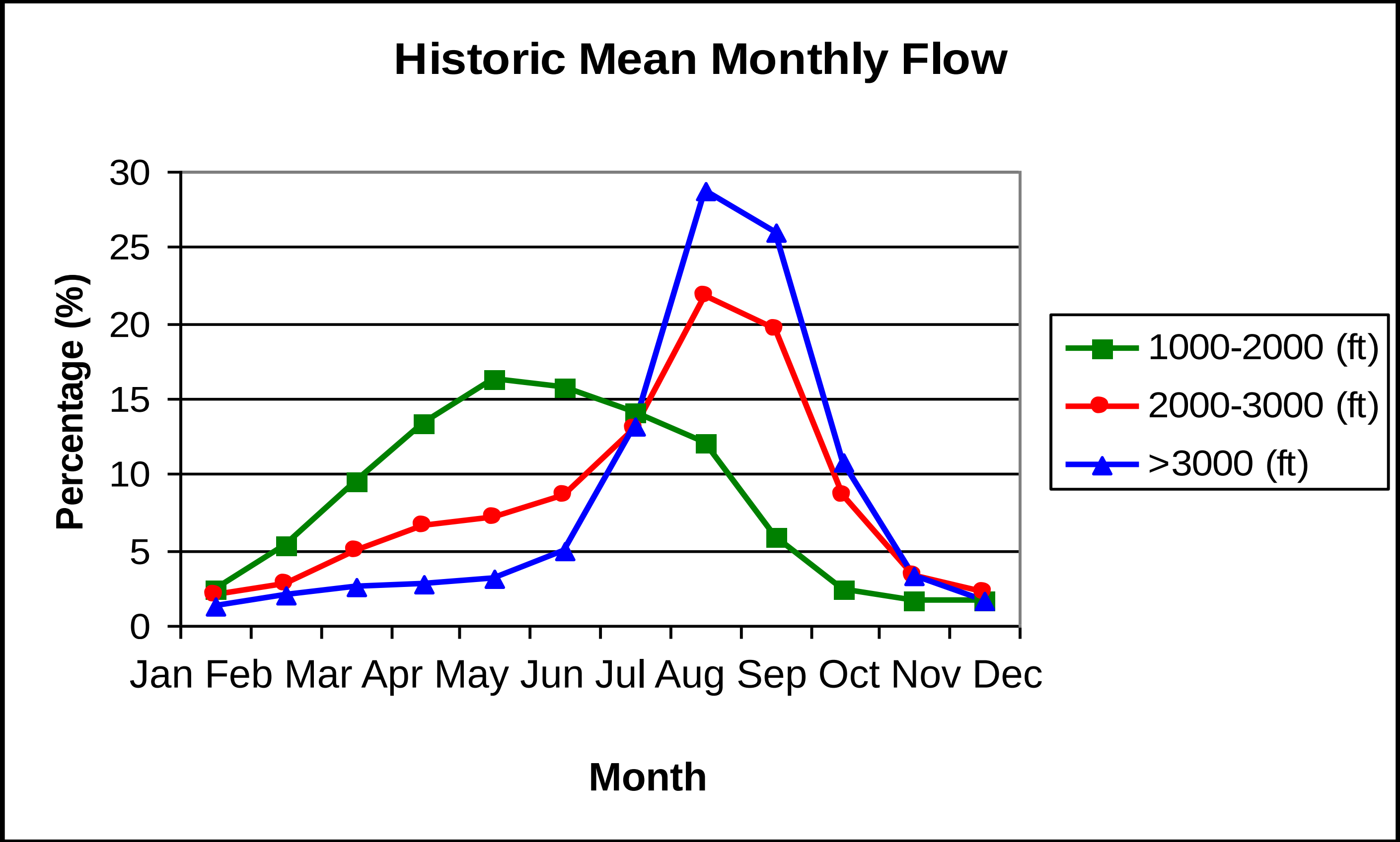


High-Elevation System



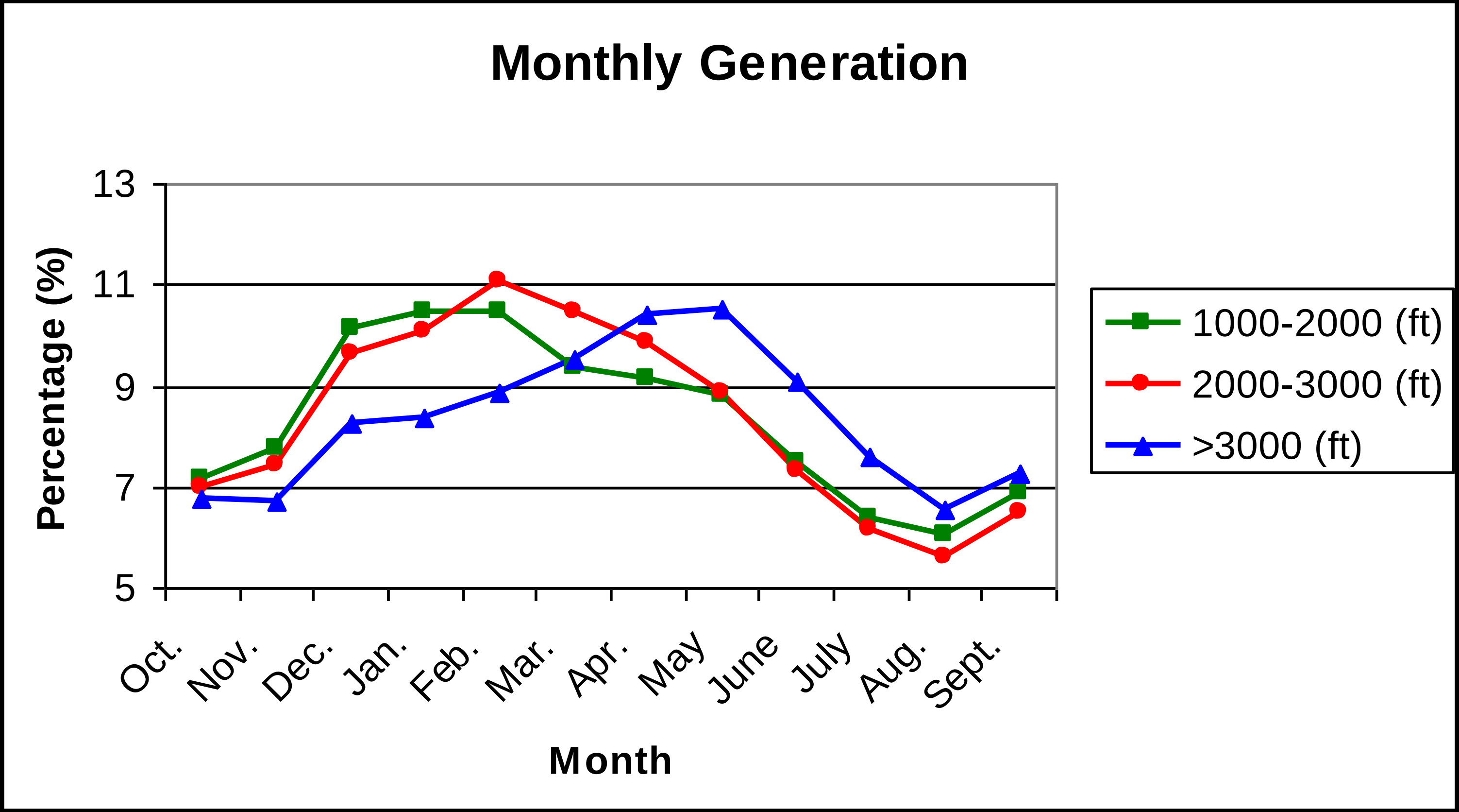
- 156 High-elevation power plants
- Snowpack dependant
- High-head, little head-storage effect
- Limited storage or flow data!!

High-Elevation Runoff (Snowpack Effect)



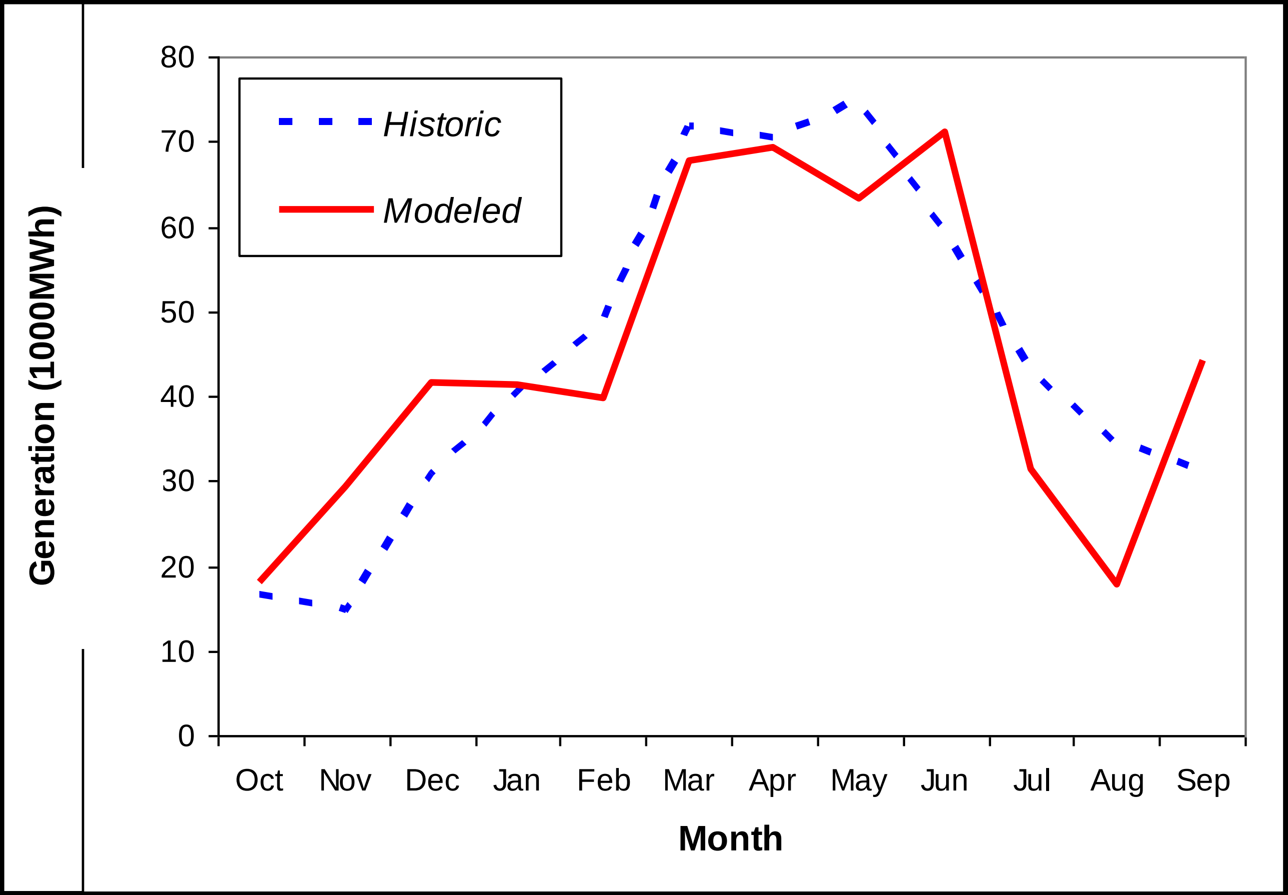
$$runPercent(i) = \frac{average\_Runoff(i)}{average\_Annual\_Runoff}$$

High-Elevation Generation (Snowpack Effect)



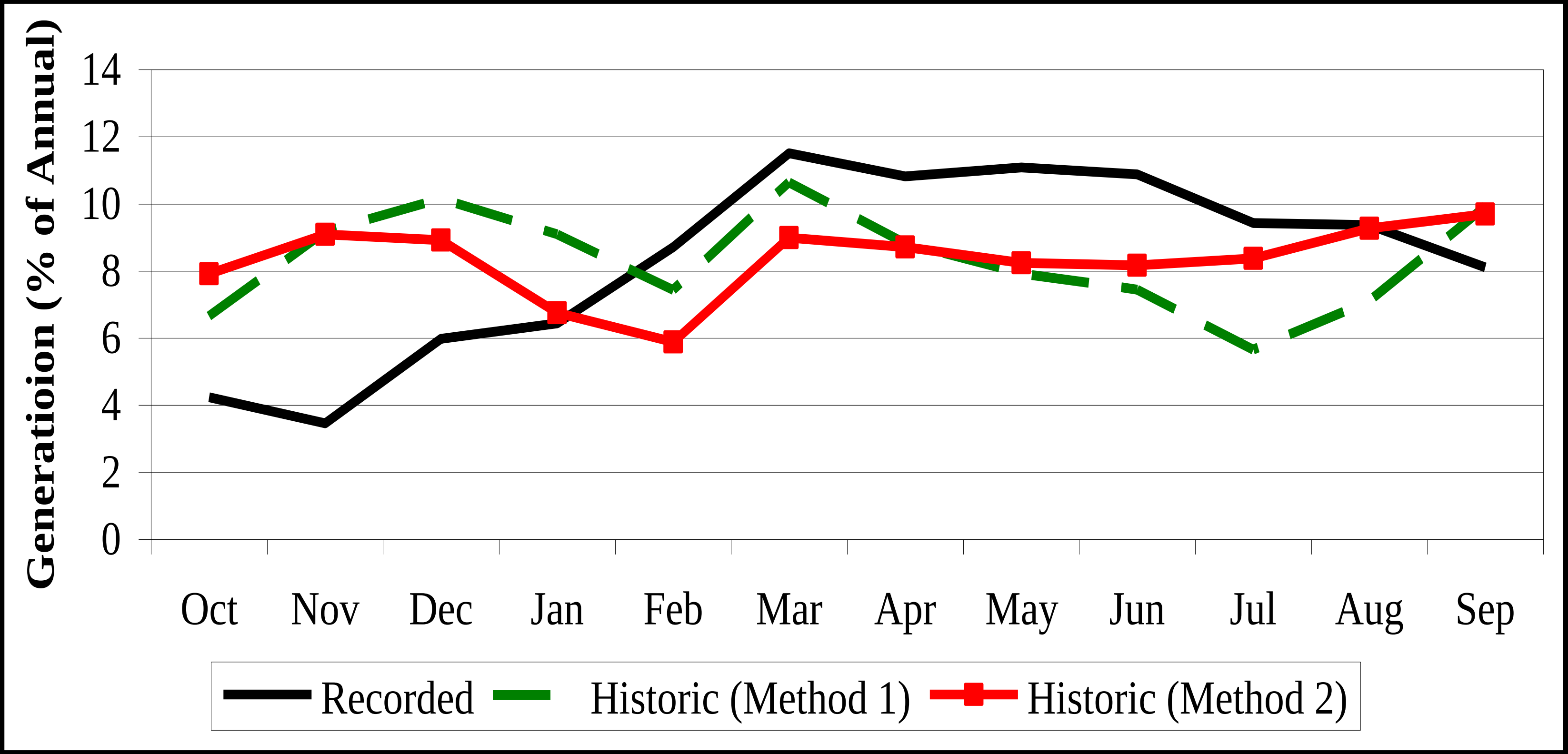
$$genPercent(i) = \frac{average\_generation(i)}{average\_Annual\_generation}$$

White Rock



Historic monthly electricity generation and optimized monthly electricity generation (by EBHOM) in an average year

SMUD System



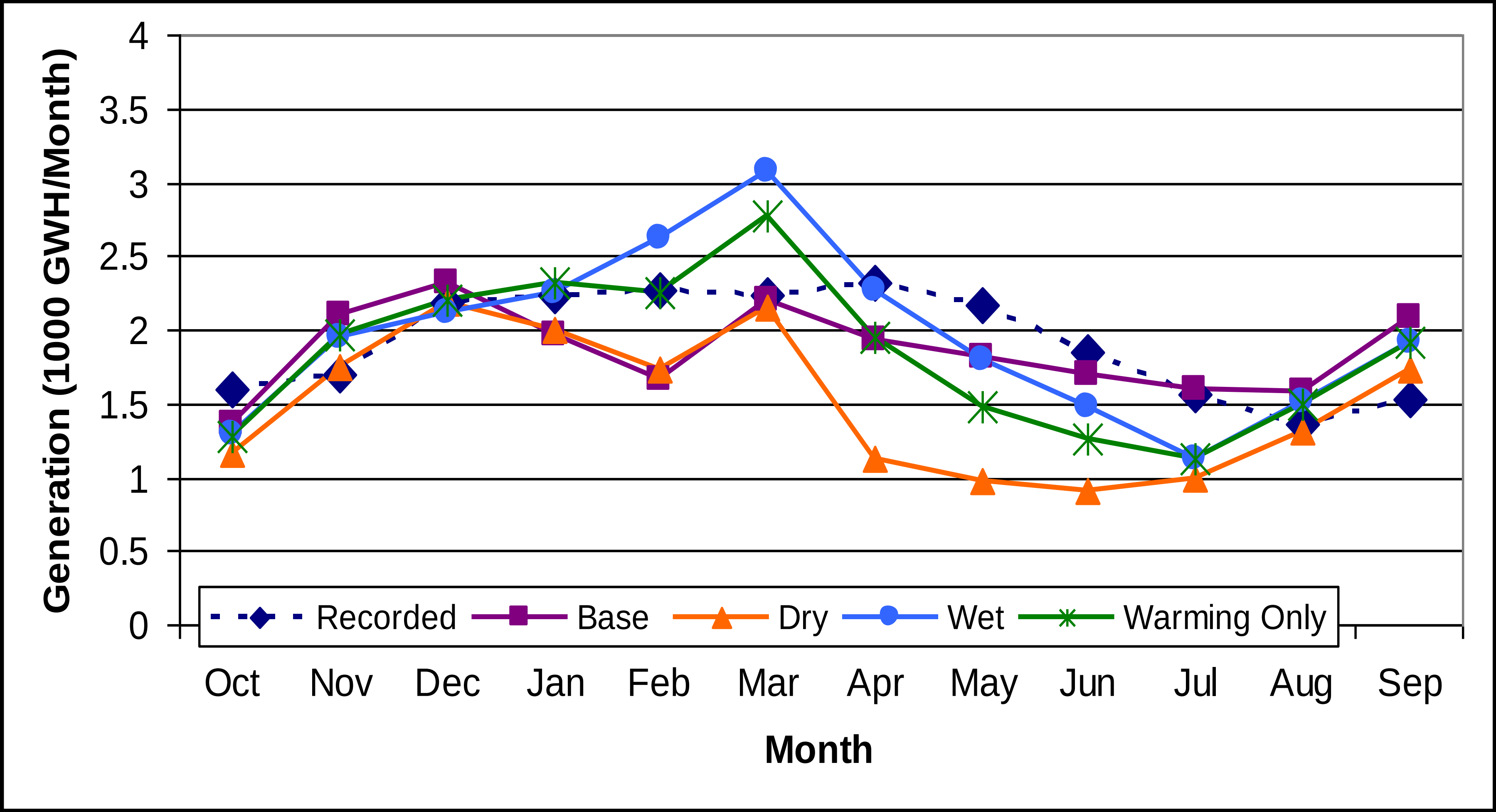
Comparison of EBHOM and traditional optimization applied to SMUD system

High-Elevation Model Results

137 of 156 hydropower plants

1984 – 1998 period

Monthly Generation

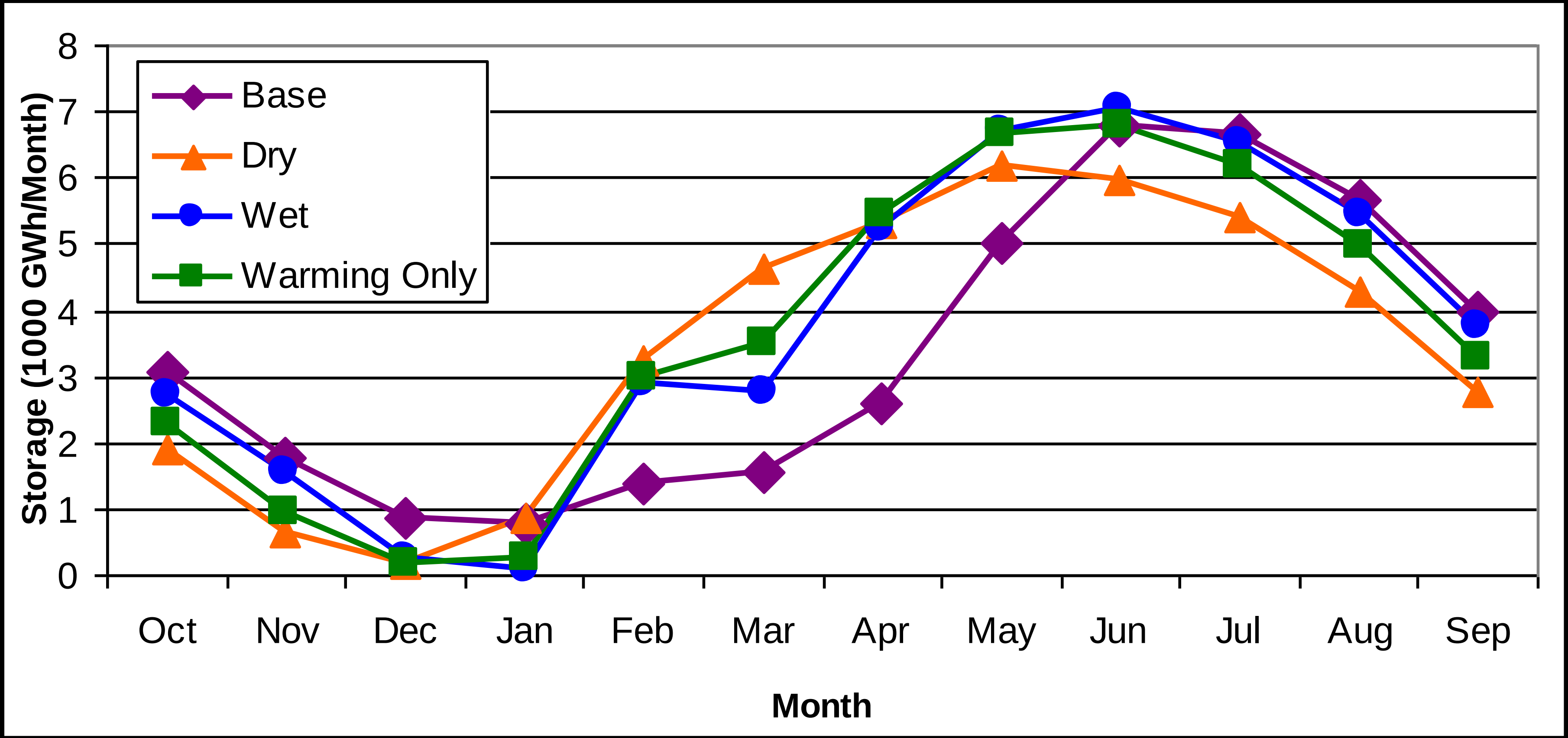


Model Results

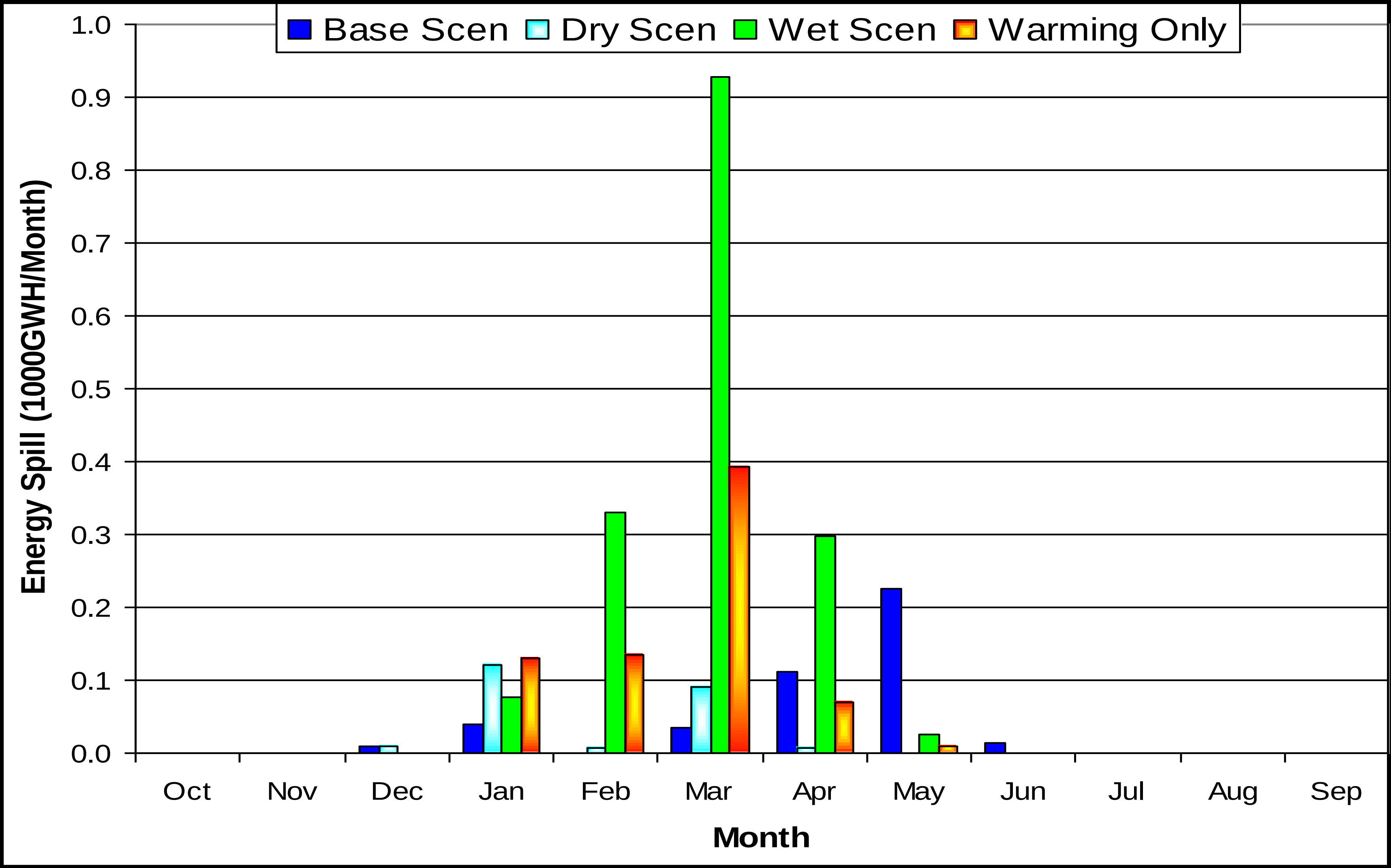
	Scenario			
	Base	***Dry***	***Wet***	***Warming-Only***
Generation (1000 GWH/yr)	22.3	18.0	23.4	22.0
Generation Change with Respect to the Base Case (%)		- 19.3	+ 4.8	- 1.4
Spill (MWH/yr)	433	224	1,661	735
Spill Change with Respect to the Base Case (%)		- 46.0	+ 283.9	+ 58.8
Revenue (Million $/yr)	1,449	1,271	1,483	1,435
Revenue Change with Respect to the Base Case (%)		- 12.3	+ 2.3	- 0.9

average of results over 1984-1998 period

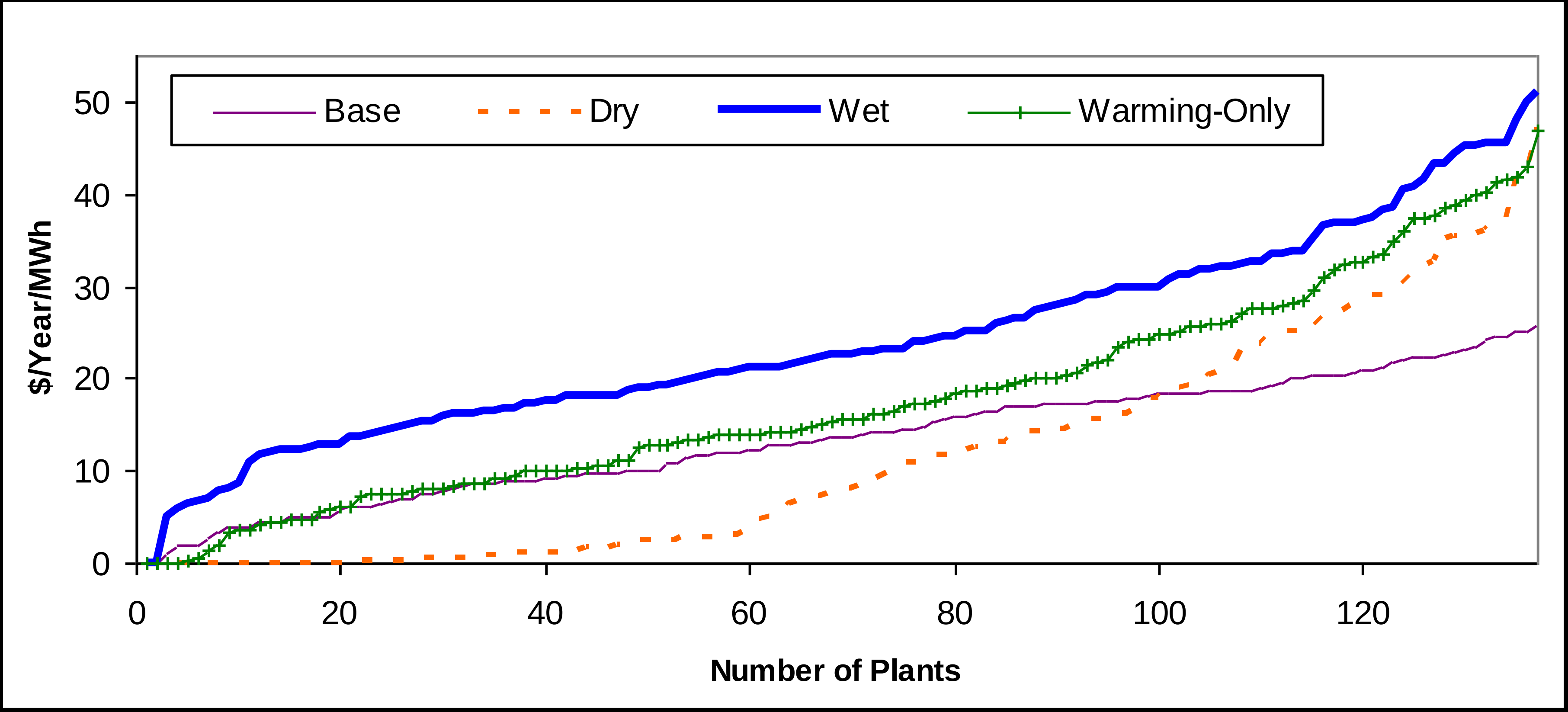
Average total end-of-month energy storage (1984-1998)



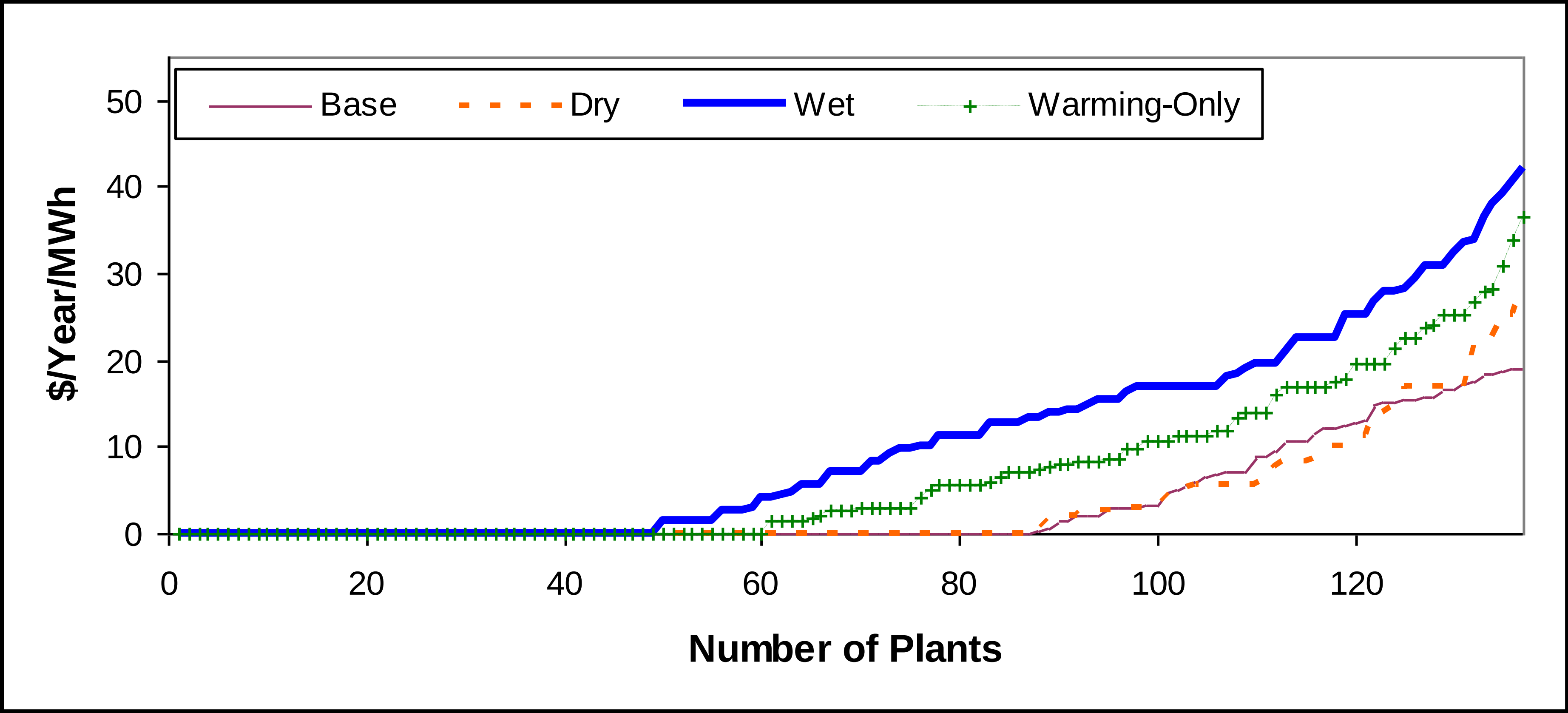
Average monthly energy spill (1984-1998)



Benefit of Storage Capacity Expansion



Benefit of Generation Capacity Expansion



Limitations of EBHOM

- NSM Limitations
- Few stream gauges
- Coarse elevation ranges
- Hydrologic variability
- Perturbation ratios
- Energy demand/price changes
- Deterministic (perfect foresight)
- No Environmental Constraints

Overall Conclusions

- Sierra loses snowpack, the natural reservoir.
- Storage works. Generation changes more with total runoff than seasonal runoff shift.
- Problems for smaller high-elevation reservoirs - more spills even without change in total runoff
- Drier climate causes more problems than wetter climate causes benefits.
- Revenue reduction may be economically insufficient to justify expanding storage or generation capacity.

Next Steps?

- Climate change effects on energy demand/ price
- More detailed high-elevation studies

Acknowledgements

- Supported by CA Energy Commission (PIER) and the Resources Legacy Fund Foundation
- Maury Roos, CA DWR
- Omid Rouhani, UC Davis
- Marcelo Olivares, UC Davis
- Sebastian Vicuna, UC Berkeley

Estimated Impacts of Climate Warming on California's High-Elevation Hydropower

Kaveh Madani[1] and Jay R. Lund[2]

Department of Civil and Environmental Engineering

University of California, Davis, CA 95616, USA

Phone: 530-752-5671 Fax: 530-752-7872

Email: [1]kmadani@ucdavis.edu / [2]jrlund@ucdavis.edu

Abstract

California's high-elevation hydropower system is composed of more than 150 power plants, most with modest reservoir storage capacity, which supply roughly 74 percent of California's in-state hydropower. This system was designed to take advantage of snowpack, a natural reservoir. The expected shift of runoff peak from spring to winter as a result of snowpack reduction due to climate warming might have important effects on power generation and revenues in California. Thus, with climate warming, the adaptability of the high-elevation hydropower system is in question. With so many hydropower plants in California, estimation of climate warming effects by conventional simulation or optimization methods would be tedious and expensive. An Energy-Based Hydropower Optimization Model (EBHOM), estimated from 15 years of generation data for 137 hydropower plants, was developed to facilitate practical climate change and other low-resolution system-wide hydropower studies. Employing recent historic hourly energy prices, the model is used to explore energy generation in California for three climate warming scenarios (dry warming, wet warming, and warming only) over 15 years, representing a range of hydrologic conditions. While dry warming and warming-only climate changes reduce average hydropower revenues, wet warming could increase revenue. The available storage and generation capacities help compensate for snowpack losses to some extent. Storage capacity expansion and to a lesser extent generation capacity expansion both increase revenues. However, such expansions might not be cost-effective.

Keywords: climate warming, climate change, hydropower, optimization, Energy-Based Optimization Model (EBHOM), No-Spill Method (NSM), California, operation.

1. Introduction

Warming is expected over the 21sth century, with current projections of a global increase of 1.5ºC to 6ºC by 2100 (Pew Center on Global Climate Change 2006). The potential effects of climate change on California have been widely discussed from a variety of perspectives (Lettenmaier et al. 1990; Lettenmaier and Sheer 1991; Aguado et al. 1992; Cayan et al. 1993; Stine 1994; Dettinger and Cayan 1995; Haston and Michaelsen 1997; Gleick and Chalecki 1999; Gleick 2000; Meko et al. 2001; IPCC 2001; Carpenter and Georgakakos 2001; Snyder et al. 2002; Lund et al. 2003; Miller et al. 2003; VanRheenen et al. 2004; Brekke et al. 2004; Dettinger et al. 2004; Zhu 2004; Zhu et al. 2005; Tanaka et al. 2006; Medellin et al. 2008).

Much of California has cool, wet winters and warm, dry summers, and a resulting water supply which is poorly distributed in both time and space (Zhu et al. 2005). On average, 75 percent of the annual precipitation of 584 mm occurs between November and March, while urban and agricultural demands are highest during the summer and lowest during the winter. Spatially, more than 70 percent of California's 88 billion cubic meters (bcm) average annual runoff occur in the northern part of the state (CDWR 1998). Temperature changes due to climate change can affect the amount and timing of runoff. Climate warming is expected to shift the seasonal runoff to the wet winter months with less snowmelt runoff during spring. Such a shift might hamper California's ability to store water and generate electricity for the spring and summer months if the available storage capacity is insufficient. Currently, California's large winter snowpack (often considered the largest surface water reservoir in California) melts in the spring and early summer, replenishing water supplies during these drier months. This runoff is used for irrigation, urban supplies, hydropower production, and other purposes.

An increase in temperature decreases snowpack and would shift some precipitation from snow to rain, reducing accumulated snowpack and melting it sooner. The available stream flow from snowmelt or rain can either pass the turbines immediately to generate electricity or be stored in reservoirs to produce hydropower later. The amount of water stored is limited by storage capacity. More storage capacity allows more stored water which leads to less immediate generation and more hydropower generation later when energy prices are greater. Turbine capacity also limits hydropower generation.

California relies on hydropower for 9 to 30 percent of the electricity used in the state, depending on hydrologic conditions, averaging 15 percent (Aspen Environmental Group and M. Cubed 2005). Hydroelectricity's low cost, near-zero emissions, and ability to be dispatched quickly for peak loads are particularly valuable. As climate change affects temperature and runoff, future hydrologic conditions will affect hydropower generation. Some studies have addressed the effects of climate change on hydropower generation in California, but such analyses have been largely restricted to large lower-elevation water supply reservoirs (Lund et al. 2003; VanRheenen et al. 2004; Tanaka et al. 2006), one moderate hydropower system (Vicuna et al. 2008), or have ignored the available storage capacity at high-elevation (Madani and Lund, 2007a; b). There is still a lack of knowledge about the global warming effects on statewide hydroelectricity generation by high-elevation facilities and the adaptability of California's high-elevation hydropower system to hydrologic changes.

2. California's High-Elevation Hydropower System

Current regulators of California hydropower are snowpack and reservoirs. Snowpack is controlled by nature, and reservoirs by man. As temperatures increase, the water stored in snowpack will be released earlier in the year. The vast majority of reservoir storage capacity, over 17 million acre-feet (MAF), lies below 1,000 feet elevation, while most in-state hydropower generation capacity is at higher elevations (Aspen Environmental Group and M. Cubed 2005) and mostly in northern California. Lower elevation storage capacity is used mostly for water storage and flood control, and also produce a notable amount of hydropower. Roughly 74 percent of in-state generated hydropower is supplied by high-elevation units although only about 30 percent of in-state usable reservoir capacity is situated at high-elevation (Aspen Environmental Group and M. Cubed 2005).

The high-elevation hydropower system has less manmade storage and may be vulnerable to climate change if storage capacity cannot accommodate reduced snowpack. Most low elevation hydropower plants (below 1,000 feet) benefit from larger storage capacities and will be affected less than high-elevation hydropower generation (Tanaka et al., 2006). Energy storage and generation capacity limits at high elevation will affect the adaptability of high-elevation hydropower systems. This study investigates the potential effects of climate warming on high-elevation hydropower generation in California and the adaptability of the statewide high-elevation system as a result of changes in hydrology by application of the Energy-Based Hydropower Optimization Model (EBHOM) developed by Madani and Lund (submitted) for California's high-elevation hydropower system.

3. Method

One hundred thirty-seven high-elevation hydropower plants (above 1,000 feet) in California were identified in this study for which the historical monthly generation data were complete for the 15 year 1984 to 1998 period. Studying individual changes in generation patterns as a result of climate change for more than 130 plants by conventional simulation and optimization models would be costly and tedious, especially when basic required information such as stream flows, turbine capacities, storage operating capacities, and energy storage capacity at each reservoir are not readily available for each individual plant. Thus, this study investigates the climate change effects and adaptations through application of the Energy-Based Hydropower Optimization Model (EBHOM) (Madani and Lund, submitted) which is based on energy flows and storage instead of water volume balances. EBHOM is a monthly-based optimization model which requires all input variables including monthly runoff, storage capacity, and generation capacity in energy units. Generally, EBHOM can be applied in any hydropower system operation study where there is relatively little effect of storage on head and there is an interest in the big picture of the system and details are of lesser importance. Madani el al. (2008) found EBHOM reliable for climate change studies by comparing the results of EBHOM's and a traditional hydropower optimization model of the Sacramento Municipal Utility District (SMUD) reservoir system developed by Vicuna et al. (2008). Both models produced similar results.

Since runoff patterns vary by elevation, three elevation ranges were considered (1,000-2000 feet, 2000-3000 feet, and above 3000 feet). Runoff data were obtained for several U.S. Geological Survey (USGS) gauges representing these elevation ranges, selected in consultation with the former California Department of Water Resources (DWR) chief hydrologist. Monthly runoff distributions were found for each elevation range (Figure 1). This figure shows the value of snowpack to the system. Runoff peaks later at higher elevations where snowpack is larger and lasts longer. Average historic monthly generation data were perturbed using monthly runoff perturbation ratios of three climate change scenarios, the Dry Warm Scenario (GFDL A2-39), the Wet Warm Scenario (PCM A2-39) (as described by Vicuña et al., 2005), and the Warming-Only Scenario. A perturbation ratio is the ratio of the value of the flow (e.g., average monthly stream flow over the specific period) under a particular scenario (e.g. PCM A2-39) to the corresponding value of the same variable in the same month under baseline (historic) conditions. The perturbation ratios were adjusted for each elevation range. Dry and Wet climate warming scenarios result in 20 percent less and 10 percent more annual runoff at each elevation band, respectively. The warming-only scenario has the historical annual inflow volume, shifting only seasonal timing of flows differently for each elevation band. The ratios were applied to each month of historical runoff to create a climate change hydrology over a multi-year sequence. Figure 2 shows how runoff distributions change for different elevation ranges and climate scenarios. This enables investigation of overall system adaptability and how each hydropower plant might perform over a range of years with climate warming.

The available energy storage capacity at each power plant was estimated based on the No Spill Method (NSM) as explained in Madani and Lund (submitted) and tested in Madani et al. (2008). EBHOM was designed for net revenue maximization. In California, most hydropower plants are operated predommantly for net revenue maximization. EBHOM is applicable to systems in which the reservoir is used only for seasonal (as opposed to over-year) hydropower generation. Also, it requires a “high-head” condition where storage does not significantly affect hydropower head. EBHOM is solved in Microsoft Excel with “What’sBest”, a commercial solver package for Microsoft Excel. EBHOM’s formulation can be linear (Madani and Lund, 2007b) or non-linear (Madani and Lund, 2008). The non-linear EBHOM is solved by linear programming through piecewise linearization of the concave revenue function (Madani and Lund, submitted). Linear EBHOM does not capture the effects of off-peak and on-peak energy prices on operations well. Thus, the non-linear EBHOM was used here in which, off-peak and on-peak energy prices are captured, using a method which considers the non-linear relationship between monthly generation and monthly revenue based on recorded hourly prices (Madani and Lund, submitted). Real time hourly hydroelectricity prices for 2005 (California ISO OASIS, 2007) were used in this study.

For each year from 1984 to 1988, EBHOM was run to estimate optimal monthly reservoir storage and energy generation decisions for the 137 power plants. The model was run for four different hydrologic scenarios including the base case (Historic) hydrology and three climate change hydrologies (Dry Warming, Wet Warming, and Warming-Only). Since the model optimizes decisions one year at a time, 15 years of results were used to model variations in performance over the 1984 to 1998 period. Assuming no over-year storage, release decisions in each year are independent. Figure 3 shows the range of the estimated energy storage and generation capacities of the studied high-elevation hydropower plants. The annual energy storage capacities of most of the studied power plants are at least 1.3 times larger than their monthly generation capacity, which provides some flexibility in operations. For these power plants, active storage capacity exceeds one month of generation capacity.

4. Results

Table 1 indicates how energy generation, energy spill and annual revenue change with climate scenarios. Revenue is greatest for the Wet scenario and least for the Dry scenario. Although annual inflow is 10 percent higher than the Base case for the Wet scenario, revenue is only about 2 percent higher than the Base scenario when optimized operations are applied. This is due to storage capacity limits, the system being designed to take advantage of historical snowpack, and monthly energy prices following the historical generation pattern. Thus, although generation is almost 5 percent higher under the Wet scenario, revenue is only 2 percent higher. Energy spill is greatest under the Wet scenario due to limited storage and generation capacities.

When total annual inflow does not change for the Warming-Only scenario (shifting only runoff timing), total revenue is reduced by about 1 percent due to limited storage capacity and some limited generation capacity, and spills greatly increase over the Base case. The timing of snowmelt and the form of precipitation (as snow or rain), in addition to total runoff volume, significantly affect generation patterns and overall quantity and value. When storage capacity cannot store the peak flow from snowpack melt for release in high-value months, revenues are reduced as a result of energy spill or generation in months when energy prices are not the highest. However, some storage capacity is available to handle the extra winter runoff under a warmer climate. This provides some flexibility in operations to store winter water to be released when energy demand is higher. As a result, although annual inflow under the Dry scenario is 20 percent less than in the Base case, Dry scenario revenues are reduced by about 12 percent even though the energy generation reduction under this scenario is greater than 19 percent. Energy spills under this scenario increase relative to the Base case during peak runoff months, causing some off-peak generation losses.

4.1. Generation Changes with Climate Warming

Figure 4 shows average monthly energy generation for 1984 to 1998 hydrologic conditions, modified for different climate changes. Results are summed from all 137 power plants modeled in this study. Generally, model results suggest less generation in months with lower average energy prices to store energy for months with higher energy prices. Summer generation always is less than the Base case under all three climate warming scenarios. Generation under the Wet and Warming-Only scenarios is higher than the Base scenario from January to April due to increased runoff peaks and limited capacity to store this shift in peak runoff. If more storage capacity were available, there would be less likelihood of water bypassing turbines ("spills") from January to April. Instead, this water would be stored and released in summer, reducing generation in late winter and early spring to increase summer generation (when prices are higher). Generation under the Dry scenario is almost always less than generation under the Base scenario. From January to March, when the runoff peaks occur, Dry scenario generation is close to Base scenario generation.

Figure 5 shows the frequency of optimized monthly generation for each month over the 15 year period (1984-1998) summed for all units, under different climate hydrologies. Dry climate warming results in considerably less generation than Base generation in over 85 percent of months over the 15 year period, with almost similar levels occurring in the remaining 10 to 25 percent of the months. Under the Wet and Warming-Only scenarios, generation is slightly less than or equal to the base case 80 percent of the time. It greatly exceeds Base generation 20 percent of the time. If more storage capacity were available, generation frequency curves under Wet and Warming-Only scenarios could be closer to the Base scenario, with higher revenues. Generation curves under Wet and Warming-Only scenarios exceed the Base case 20 percent of the time when storage capacity cannot store more wet winter flows for summer and spring generation, forcing operators to release up to the turbine capacity or spill excess flows as reservoirs fill in January to April.

4.2. Reservoir Storage Changes with Climate Warming

Figure 6 shows how average end-of-month energy storage in all reservoirs combined changes with climate when reservoirs are operated for energy revenues only. Under the Base scenario, reservoirs reach their minimum storage level by the end of January to prepare to capture expected inflow from winter precipitation and later spring snowmelt. On average, reservoirs are full by June and gradually emptied for energy generation over the summer when energy prices are higher and there is little natural inflow. Under historical conditions, refill starts in January and drawdown starts in June. Although climate warming results do not appear to change these cycles much, snowpack loss generally increases average reservoir storage (stored energy) between February and May than in the Base case. With dry climate warming, energy storage peaks earlier and drawdown begins a month earlier.

4.3. Energy Spills with Climate Warming

Figure 7 shows the frequency of total monthly energy spill from the system for the study period when the system is optimized for revenue maximization. Energy spill results from runoff that can be neither stored nor sent through turbines because of limited capacities. Energy spill is the equivalent energy value of the available runoff water which cannot contribute to energy production at each site. Energy is spilled by the system in 30 percent of months under all climate scenarios, including the Base scenario. However, the magnitude of spills increases for Wet and Warming-Only scenarios, and decreases for the Dry scenario. Existing storage capacity cannot compensate for the loss of snowpack during wetter years, and overall earlier snow melt, but appears able to compensate in drier years.

What is calculated as energy spill in this study is the increased historic energy spill, because annual historical generation (actual recorded output of the system) in each year during 1984 to 1994 period was used as the annual energy input to calibrate the hydropower system model, for which spill data are unavailable. However, the calculated energy spill under the historic scenario is only 0.002 percent of total generation.

Figure 8 shows the distribution of total average monthly energy spill under different climate scenarios. Under the historic climate scenario, energy spills occur from December to June when inflow to the system peaks. The changes in the magnitude and timing of spills under different climate warming scenarios indicate the importance of runoff inflow timing and magnitude to the performance of this system.

Figure 9 plots the frequency curve of total annual spill from the system for the study period. Energy does not spill under the Base scenario for most years. Annual energy spill frequency and magnitude both increase with Wet and Warming-Only scenarios and decrease with Dry warming. As more precipitation falls as rain than snow and snow melts sooner at high elevation under climate warming, annual energy spills increase in both size and frequency as monthly runoff distribution patterns and annual volumes no longer match well with existing storage and generation capacities. Most energy spill occurs under the Wet scenario, in more than 80 percent of years. Under the Warming-Only and Dry scenarios, energy spills in more than 70 and 50 percent of years, respectively.

4.4. Revenue and Energy Price Patterns under Climate Warming

Figure 10 indicates the climate warming effects on monthly average price for generated energy. Climate warming generally increases average energy prices in more than 60 percent of months. As expected, the rise in prices is highest with dry climate warming (given the non-linear relationship between electricity price and generation quantity). Under this scenario prices are higher than the base case more than 90 percent of the time. Average received energy price frequency curves for Wet and Warming-Only scenarios show similar behavior, highlighting the importance of runoff timing over quantity for optimal system operations.

Figure 11 shows the effects of climate warming on the frequency of total annual revenues of all 137 hydropower plants studied for the period 1984 to 1998. Although monthly average prices received for generated energy were higher under the Dry scenario, the increase in prices does not compensate for the Dry scenario reduction in total energy generation. Annual revenue under the Wet scenario exceeds Base scenario revenue in 60 percent of years but is almost the same during the rest of the time. Annual revenue under the Warming-Only scenario is similar to the Base scenario.

In this study, the effects of climate warming on energy demand were neglected. To improve the estimations, in future, the effects of climate change on energy demand can be studied by defining different relationships between energy generation quantity and energy price for various scenarios (Madani and Lund, submitted).

4.5. Benefits of expanding energy storage and generation capacity

Figure 12 shows, on average, how energy storage capacity expansion changes hydropower generation revenues under different climate scenarios over the study period

(15 years). This figure indicates the average shadow price of energy storage capacity (the increase in annual revenue per 1 MWh energy storage capacity expansion) for all 137 reservoirs. For instance, increase in annual revenue per 1 MWh energy storage capacity expansion is less than $5 for 103 of the studied power plants under the Dry scenario. Storage capacity expansion reduces spills and allows for more release in summer when energy prices are higher. Storage capacity expansion can increase average annual revenues for almost all hydropower plants under all climate scenarios, but such expansion might not be justified due to expansion costs. As expected, benefits of capacity expansion are greater for Wet and Warming-Only scenarios. The annual marginal benefit of storage capacity expansion is greatest under the Wet scenario when more energy is available to store. Even with the historical hydrology, expanding storage capacity increases total annual revenues in all years because more storage capacity allows for more flexible operations needed to generate more energy during peak price times. While about 100 hydropower plants benefit more from energy storage capacity expansion under the Base scenario than the Dry scenario, the other 37 hydropower plants benefit more from energy storage capacity expansion under the Dry scenario than the Base scenario.

Figure 13 indicates the average shadow price of energy generation capacity (the increase in annual revenue per 1 MWh of monthly energy generation capacity expansion) for all 137 plants under different climate scenarios. Generation capacity expansion does not increase the annual revenues of about 90 hydropower plants under the Base and Dry scenarios. About 50 of the studied hydropower plants do not need energy generation capacity expansion under all types of climate warming, meaning that those units do not experience energy spill at all even with warmer climates. Although generation capacity expansion produces benefits, expansion costs might be prohibitive. Similar to storage capacity expansion, benefits of energy generation capacity expansion are higher under Wet and Warming-Only than Base and Dry scenarios. Comparison of Figures 12 and 13 shows that energy storage capacity expansion is typically more beneficial than energy generation capacity expansion if the expansion costs are the same.

5. Limitations

Models are not perfect and optimized results are optimized to particular conditions and objectives. During model development many simplifying assumptions are made which should be considered in interpreting the results. However, simulation and optimization models are useful in studying resource management problems. Here, the results give some insights on how the system works and how it might adapt under different climate warming scenarios.

Calibration of EBHOM for this study (Madani and Lund, submitted) is likely to under-estimate energy storage capacities and therefore also underestimate adaptability of the system to climate change. Availability of spill or energy storage capacity data would reduce this source of error.

California is big and variable in hydrology. Assuming the same seasonal pattern for inflows in north and south at the same elevation will cause some inaccuracies. A 1000 feet range covers a great variability in hydrology. Smaller elevation ranges might increase the accuracy of the estimation. Since many power plants are in the 3000-4000 feet elevation range, it might be worthwhile to study this range separately. Also, more gauges might be considered for each elevation range.

As a first step in studying the adaptability of California's high-elevation hydropower system to climate warming, this study looks at flexibility of operations without considering environmental constraints.

Here, energy prices were imposed on each individual power plant. Instead, total demands might be imposed to the system of one hundred thirty-seven plants. This gives more flexibility in operation and reaction of the system. High-elevation plants at lower elevations which receive the peak flows earlier can generate more in earlier months while higher plants generate more, later during the year. Although the timing of flow will change, there is still a difference in flow patterns at different elevation ranges which benefits the system if operated wisely. By integrating operations of individual hydropower systems that span different watersheds and elevation bands, greater operational flexibility to respond to changes in climate, streamflow, and runoff may be possible.

With climate warming, demands are likely to increase in warmer months from higher temperatures. This could affect energy prices. EBHOM employed recorded real-time energy prices for finding revenue curves which define the relation between monthly energy generation and energy price. The prices used here are from 2005 which do not exactly match energy prices of the 1984 to 1995. This might cause some inaccuracies in EBHOM's estimation of revenues and energy prices. However, this limitation might not affect the other results (generation, spill, and storage) much as the energy price trends are similar over the years of study. Application of price data sets which are longer than one year in future might improve the accuracy of model results.

For this application we assume inflow distributions adhere to a fixed seasonal pattern. Inflow distributions are likely to be more local and vary more between years. Here, the model optimizes revenue based on its perfect information about the year's hydrological pattern. Such management is impossible in practice.

6. Conclusions

In absence of detailed information about the available energy storage capacity at high-elevation in California, this study applied a simple low-resolution approach for estimating the adaptability of California's high-elevation hydropower generation to climate warming. Substituting the estimated energy content of runoff water inflows and storage for these relatively high-head hydropower units and estimating seasonal inflow distribution patterns by elevation band allowed preliminary optimization-driven monthly system operations modeling of more than 137 hydropower plants with various climate changes.

With climate warming, California loses snowpack which has functioned historically as a natural reservoir to delay runoff, but considerable energy storage and generation capacity remaining available. The EBHOM's results show that most extra runoff in winter months from climate warming can be accommodated by the available storage capacity at high-elevation sites for average years. Lower-elevation reservoirs, constructed primarily for water supply, already have substantial re-regulation capacity for seasonal flow adjustments (Tanaka et al. 2006). However, operating rules should change with climate warming to adapt the system to changes in hydrology (Medellin et al. 2008).

Generally, climate warming alone reduces high-elevation hydropower generation and revenue, without changes in total runoff, due solely to changes in seasonal runoff timing. Energy spills increase dramatically under Wet and Warming-Only scenarios with existing storage and generation capacities. More storage capacity would increase revenues but might not be cost effective. Storing water in reservoirs helps shift energy runoff reductions to months with lower energy prices to reduce economic losses. More generation capacity also increases revenues by reducing energy spill. Annual marginal benefits of capacity expansion are higher for storage than for generation. Nevertheless, current storage and generation capacities give the system some flexibility to adapt to climate changr. Although the Dry scenario examined in this study has 20 percent less runoff than the base historical hydrology, system-wide, revenues decrease by less than 12 percent through optimally re-operating storage and generation facilities within existing capacity limits. Thus, the current storage and generation capacities can compensate for some snowpack loss, and for the Wet and Warming-Only scenarios with very little revenue decrease.

Limited capacities cannot take full advantage of increased energy runoff under the Wet scenario. The Wet warming scenario examined here has 10 percent more runoff than the historical hydrology, but only 5 percent more generation and 2 percent more average annual revenues. In a Warming-Only scenario with unchanged historical precipitation, generation and revenues decrease by 1.4 and almost 1 percent, respectively.

This study required some simplifying assumptions. Nevertheless, it gives insights and suggests some degree of adaptive capability to climate warming. Future studies should address environmental and other constraints, include demand and price impacts of climate change, and apply refined estimates of varied hydrologic changes from climate change across California.

Acknowledgments

The authors thank Omid Rouhani from University of California, Davis for his help in EBHOM development, Marcelo Olivares from University of California, Davis for providing hourly energy price data, Maury Roos from California Department of Water Recourses for providing the names of reliable high-elevation gauges in California, and Jery Stedinger from Cornell University for his early feed-back on the work. This work was funded by the California Energy Commission's Public Interest Energy Research (PIER) program and the Resources Legacy Fund Foundation.

References

Aguado, E., D. Cayan, L. Riddle, M. Roos (1992); "Climate Fluctuations and the Timing of West Coast Streamflow"; Journal of Climate, Vol. 5, pp. 1468-1483.

Aspen Environmental Group and M. Cubed (2005); "Potential changes in hydropower production from global climate change in California and the western United States"; California Climate Change Center, CEC-700-2005-010, June 2005 (http://www.energy.ca.gov/2005publications/CEC-700-2005-010/CEC-700-2005-010.PDF).

Brekke, L.D., N.L. Miller, K.E. Bashford, N.W.T. Quinn, and J.A. Dracup, 2004. "Climate Change Impacts Uncertainty for Water Resources in the San Joaquin River Basin, California." Journal of the American Water Resources Association, Vol. 40, No. 1, pp. 149-164.

California ISO OASIS (2007), Hourly Average Energy Prices, California Independent System Operator (ISO) Open Access Same-Time Information System (OASIS) web site, http://oasis.caiso.com/ (May 2007).

Carpenter, T.M. and Georgakakos, K.P. (2001); "Assessment of Folsom lake response to historical and potential future climate scenarios: 1. Forecasting"; Journal of Hydrology, Vol. 249, pp. 148-175.

Cayan, D.R., L.G. Riddle, and E. Aguado (1993); "The Influence of Precipitation and Temperature on Seasonal Streamflow in California"; Water Resources Research, Volume 29(4), pp 1127-1140.

CDWR (California Department of Water Resources) (1998); "The California Water Plan Update"; Bulletin 160-98, Volume 1, California Department of Water Resources, Sacramento, California.

Dettinger, M. D. and Cayan D. R. (1995); "Large-Scale Atmospheric Forcing of Recent Trends toward Early Snowmelt Runoff in California"; Journal of Climate, Vol. 8(3), pp. 606–623.

Dettinger, M.D., Cayan D. R., Meyer M. K., and Jeton A. E. (2004); "Simulated Hydrologic Responses to Climate Variations and Change in the Merced, Carson, and American River Basins, Sierra Nevada, California, 1900-2099"; Climatic Change, Volume 62, pp. 283- 317.

Gleick, P.H. and Chalecki E. L. (1999); "The Impact of Climatic Changes for Water Resources of the Colorado and Sacramento-San Joaquin River Systems"; Journal of the American Water Resources Association, Vol. 35(6), pp. 1429-1441.

Glieck, P.H. (2000); "The Report of the Water Sector Assessment Team of the National Assessment of the Potential Consequences of Climate Variability and Change"; Pacific Institute for Studies in Development, Environment, and Security, Oakland, California.

Haston, L., Michaelsen J. (1997); "Spatial and Temporal Variability of Southern California Precipitation over the Last 400 yr and Relationships to Atmospheric Circulation Patterns"; Journal of Climate, Vol. 10(8), pp.1836 1852.

IPCC (Intergovernmental Panel on Climate Change) (2001); “Climate Change 2001: The Scientific Basis”; Cambridge University Press, Cambridge, United Kingdom, 881 pp.

Lettenmaier, D. P., Gan, T. Y. (1990); “Hydrologic Sensitivity of the Sacramento-San Joaquin River Basin, California, to Global Warming”; Water Resources Research; Vol. 26, No. 1, pp. 69-86.

Lettenmaier, D. P. and Sheer D. P. (1991); “Climatic Sensitivity of California Water Resources,” Journal of Water Resources Planning and Management; Vol. 117, No. 1, Jan/Feb, pp. 108-125.

Lund, J. R., Zhu T., Jenkins M. W., Tanaka S., Pulido M., Taubert M., Ritzema R., Ferriera I. (2003); “Climate Warming & California’s Water Future”; Appendix VII, California Energy Commission: Sacramento. pp. 1–251 (http://www.energy.ca.gov/reports/2003-10-31_500-03-058CF_A07.PDF).

Madani, K., J.R. Lund, (2007a) “Aggregated Modeling Alternatives for Modeling California’s High-elevation Hydropower with Climate Change in the Absence of Storage Capacity Data,” *Hydrological Science and Technology,* Vol. 23, No. 1-4, pp. 137-146.

Madani K., J. R, Lund (2007b) “High-Elevation Hydropower and Climate Warming in California”, *Proceeding of the 2007 World Environmental and Water Resources Congress, Tampa, Florida,* (Ed) Kabbes K. C., ASCE.

Madani K., Lund J. R. (submitted) " Modeling California's High-Elevation Hydropower Systems in Energy Units", Water Resources Research.

Madani K., S. Vicuna, J. Lund, J. Dracup, and L. Dale (2008); “Different Approaches to Study the Adaptability of High-Elevation Hydropower Systems to Climate Change:

The Case of SMUD's Upper American River Project", *Proceeding of the 2008 World Environmental and Water Resources Congress, Honolulu, Hawaii*, (Ed) Babcock R. W. and Walton R., ASCE.

Medellín-Azuara J., Harou J. J., Olivares M. A., Madani K., Lund J. R., Howitt R. E., Tanaka S. K., Jenkins M. W., Zhu T. (2008); "Adaptability and Adaptations of California's Water Supply System to Dry Climate Warming"; Climatic Change. 87 (Suppl 1):S75–S90.

Meko, D.M., M.D. Therrell, C.H. Baisan, and M.K. Hughes (2001); "Sacramento River Flow Reconstructed to A.D. 869 From Tree Rings"; Journal of the American Water Resources Association (JAWRA); Vol. 37(4); pp. 1029-1039.

Miller, N. L., Bashford, K. E., and Strem, E. (2003); "Potential Impacts of Climate Change on California Hydrology"; Journal of the American Water Resources Association, Vol. 39(4), pp. 771-784.

Pew Center on Global Climate Change (2006); (www.pewclimate.org/global-warming-basics/).

Snyder, M.A., J.L.Bell, L.C. Sloan, P.B. Duffy, and B. Govindasamy (2002); "Climate Responses to a Doubling of Atmospheric Carbon Dioxide for a Climatically Vulnerable Region"; Geophysical Research Letters; Vol. 29(11), 10.1029/2001GL014431.

Stine, S. (1994); "Extreme and Persistent Drought in California and Patagonia During Medieval Time"; Nature, Vol. 369, pp 546-549.

Tanaka S. T., Zhu T., Lund J. R., Howitt R. E., Jenkins M. W., Pulido M. A., Tauber M., Ritzema R. S. and Ferreira I. C. (2006); "Climate Warming and Water Management Adaptation for California"; Climatic Change; Vol. 76, No. 3-4.

VanRheenen, N.T., A.W. Wood, R.N. Palmer, D.P. Lettenmaier (2004); "Potential Implications of PCM Climate Change Scenarios for Sacramento–San Joaquin River Basin Hydrology and Water Resources"; Climatic Change; Vol. 62(1-3), pp. 257-281.

Vicuña S., Leonardson R., Dracup J. A., Hanemann M., Dale L. (2005); "Climate Change Impacts on High Elevation Hydropower Generation in California's Sierra Nevada: A Case Study in the Upper American River"; California Climate Change Center, CEC-500-2005-199-SD, December 2005 (http://www.energy.ca.gov/2005publications/CEC-500-2005-199/CEC-500-2005-199-SF.PDF).

Vicuna S., R. Leonardson, M. W. Hanemann, L. L. Dale, and J. A. Dracup (2008) Climate change impacts on high elevation hydropower generation in California's Sierra Nevada: a case study in the Upper American River, *Climatic Change*, 28 (Supplement 1), 123-137.

Zhu T. (2004); "Climate Change and Water Resources Management: Adaptations for Flood Control and Water Supply"; Ph.D. Dissertation, University of California, Davis.

Zhu T., Jenkins M. W., and Lund J. R. (2005); "Estimated Impacts of Climate Warming on California Water Availability Under Twelve Future Climate Scenarios." Journal of the American Water Resources Association (JAWRA); Vol. 41(5):pp. 1027-1038.

Table 1. EBHOM's results (average of results over 1984-1988 period) for different climate scenarios

	Base	***Dry***	***Wet***	***Warming-Only***
Generation (1000 GWH/yr)	22.3	18.0	23.4	22.0
Generation Change with Respect to the Base Case (%)		- 19.3	+ 4.8	- 1.4
Spill (MWH/yr)	433	224	1,661	735
Spill Change with Respect to the Base Case (%)		- 46.0	+ 283.9	+ 58.8
Revenue (Million $/yr)	1,449	1,271	1,483	1,435
Revenue Change with Respect to the Base Case (%)		- 12.3	+ 2.3	- 0.9

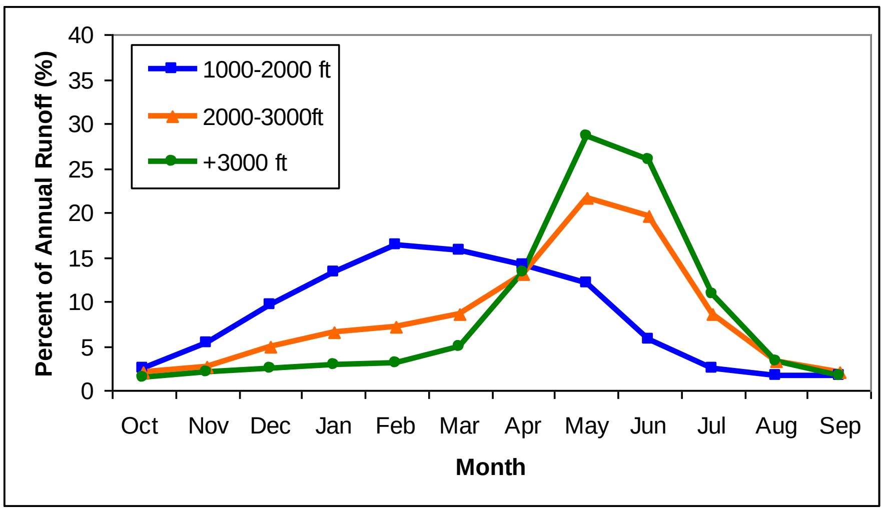
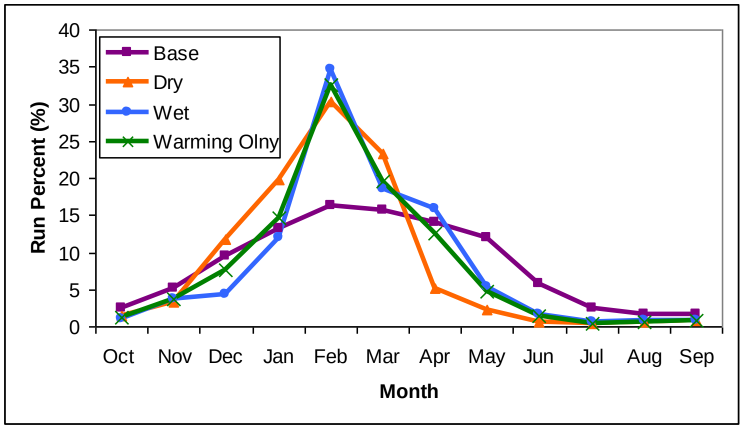
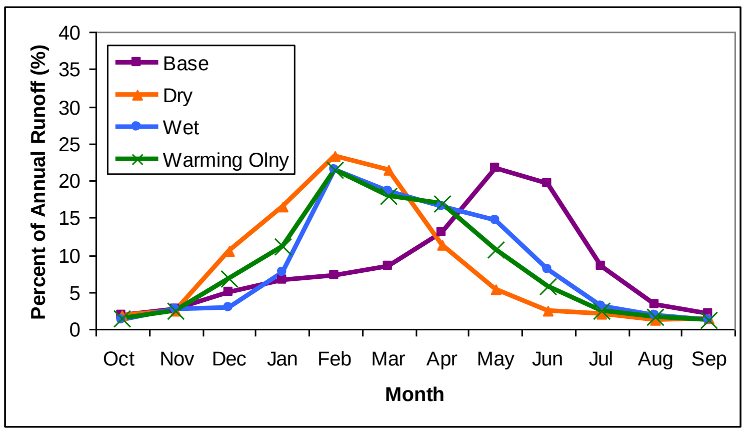


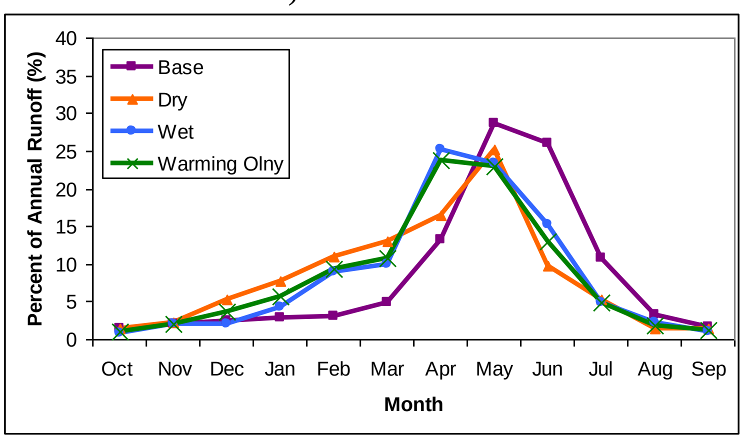
Figure 1. Monthly runoff distributions at different elevation ranges



a) 1000-2000 ft



b) 2000-3000 ft



c) + 3000 ft

Figure 2- Monthly runoff distributions for different climate change scenarios and elevation ranges

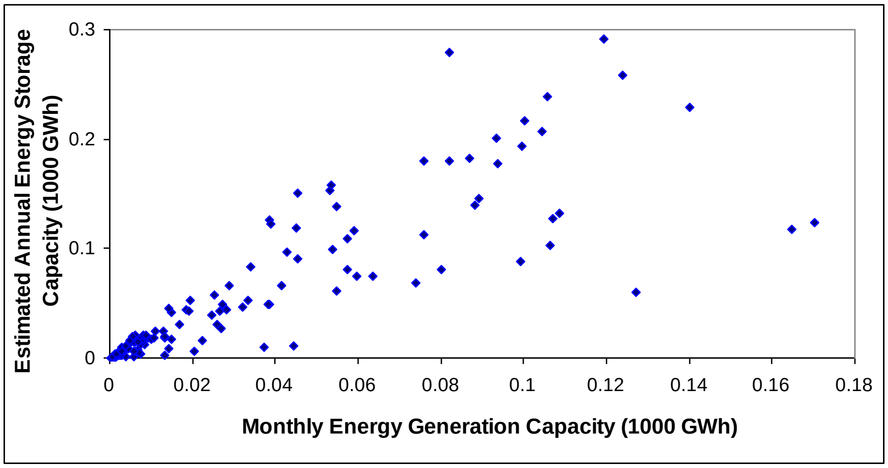


Figure 3. Range of the estimated energy storage and generation capacities of the 137 studied high-elevation hydropower plants in California

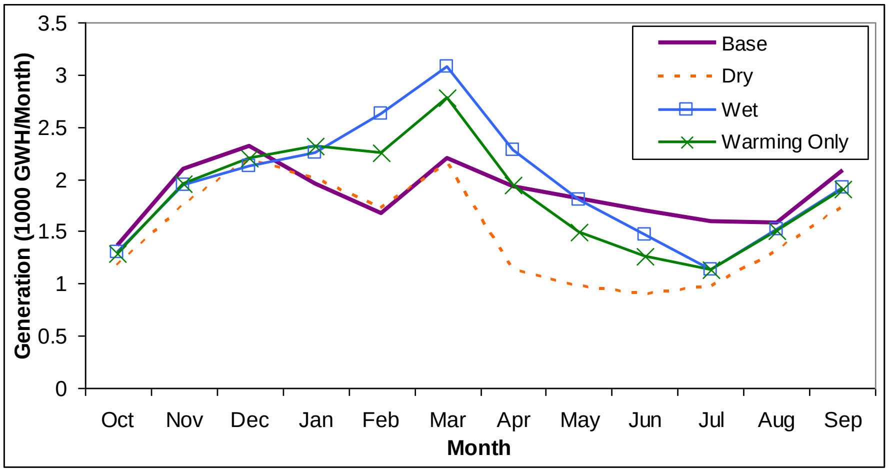


Figure 4. Average monthly generation (1984-1998) under different climate scenarios

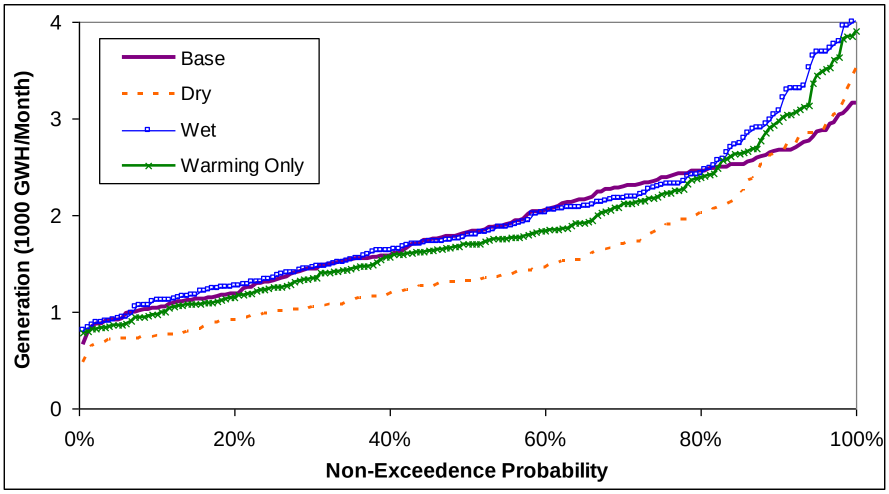


Figure 5. Frequency of optimized monthly generation (1984-1998) under various climate scenarios (all months, all years, all units)

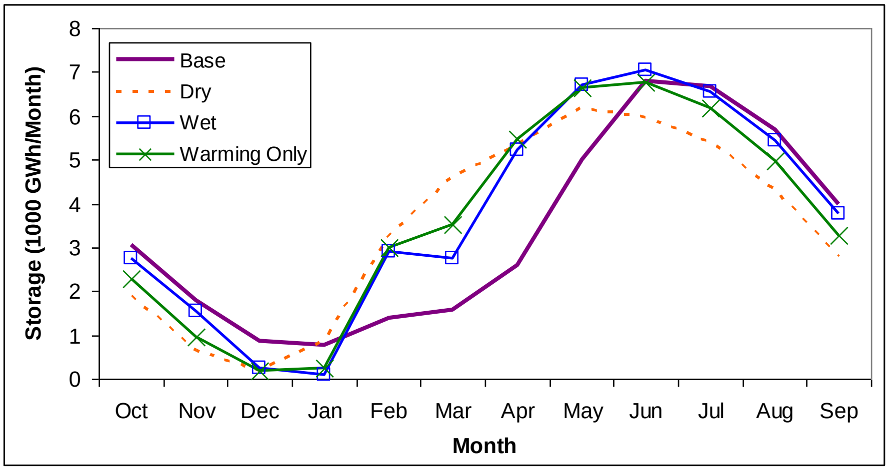


Figure 6. Average total end-of-month energy storage (1984-1998) under different climate scenarios

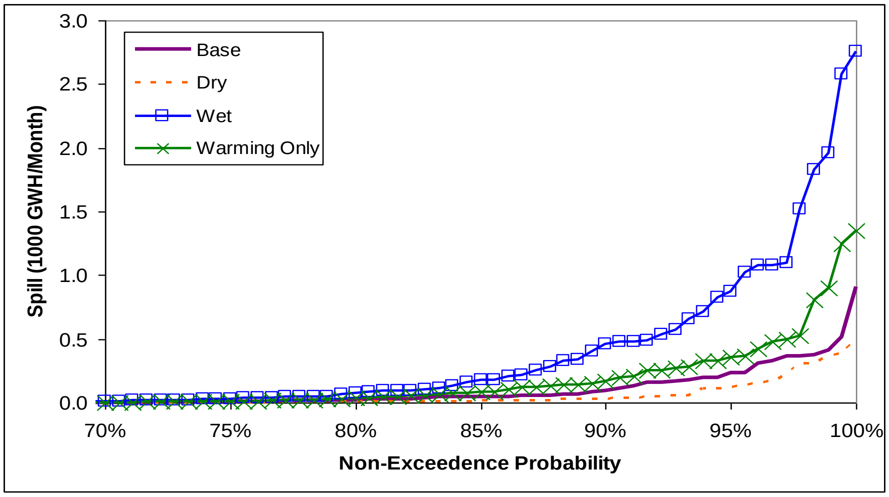


Figure 7. Frequency of total monthly energy spill (1984-1998) under different climate scenarios (all months, all years, all units)

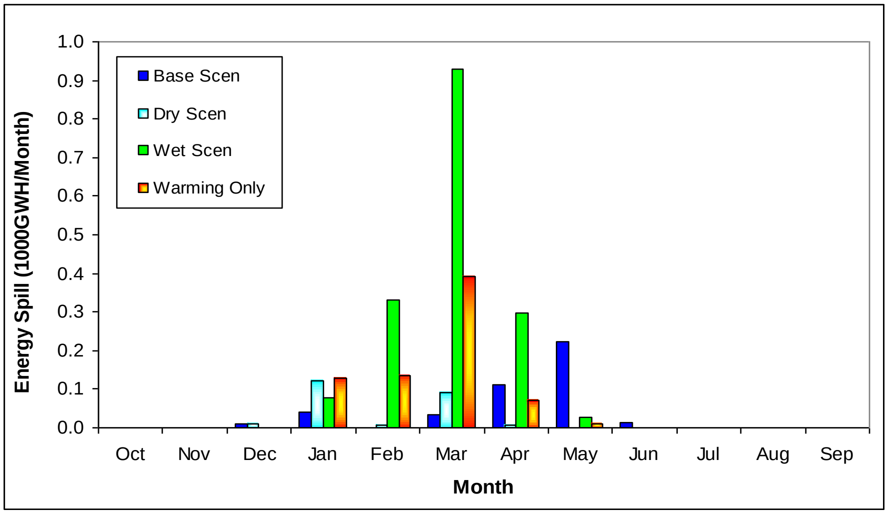


Figure 8. Average monthly total energy spill (1984-1998) under different climate scenarios

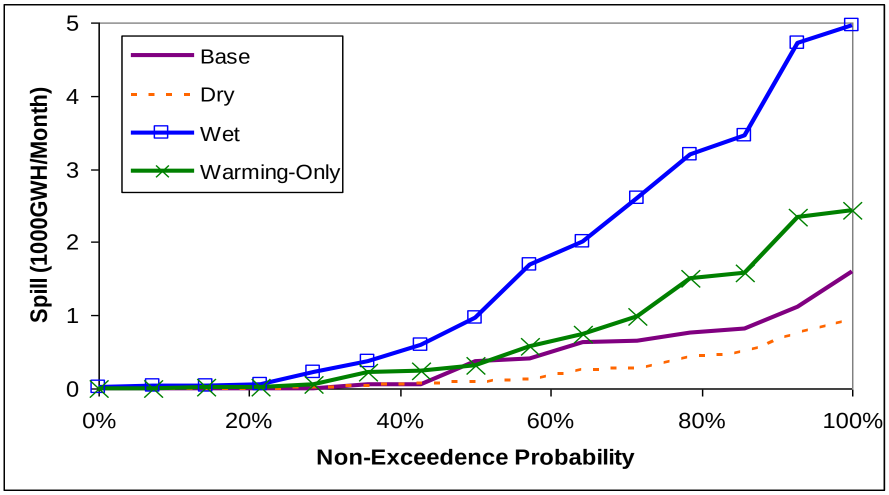


Figure 9. Frequency of total annual energy spill (1984-1998) under different climate scenarios (all years, all units)

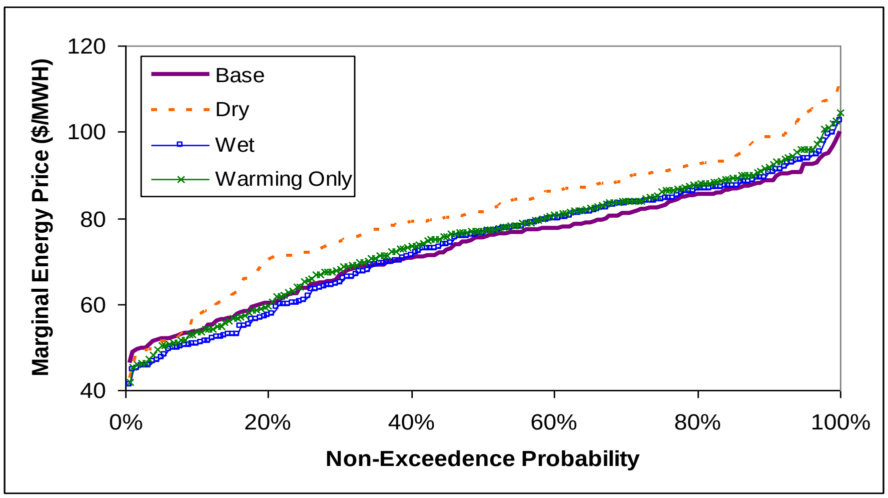


Figure 10. Frequency of monthly energy price (1984-1998) under different climate warming scenarios (all months, all years, all units)

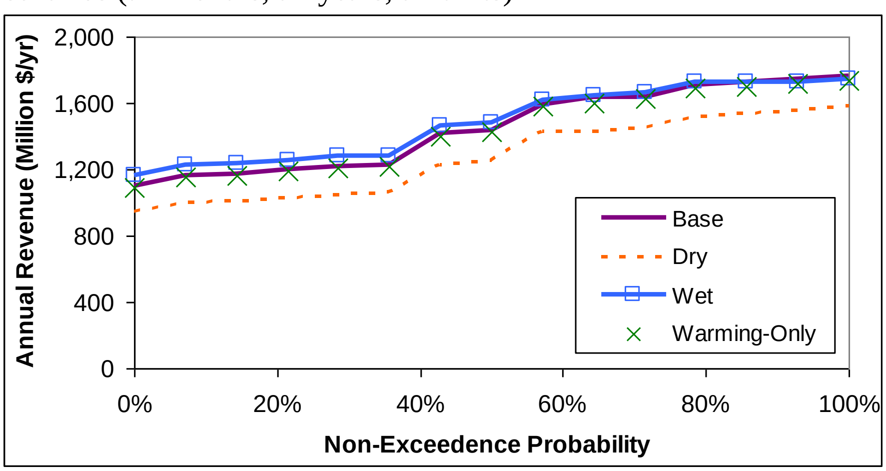


Figure 11. Frequency of total annual revenue (1984-1998) under different climate scenarios (all years, all units)

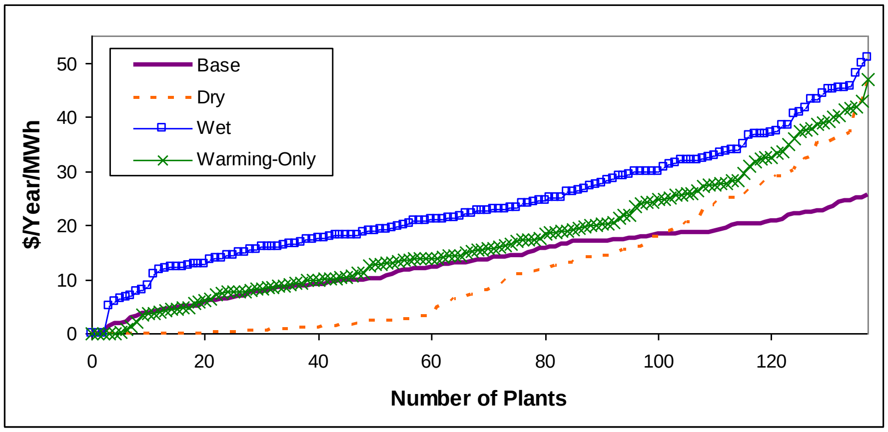


Figure 12. Average shadow price of energy storage capacity of 137 hydropower units in California in the 1984-1998 period under different climate scenarios

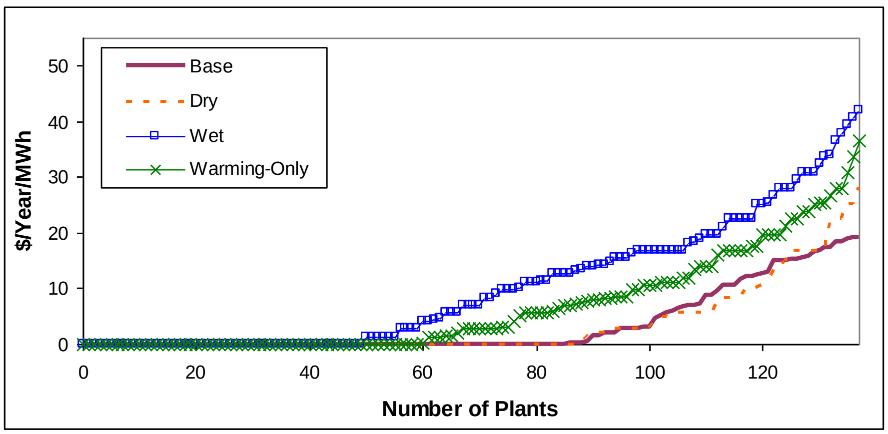


Figure 13. Average shadow price of energy generation capacity of 137 hydropower units in California in the 1984-1998 period under different climate scenarios

Modeling California's High-Elevation Hydropower Systems in Energy Units

Kaveh Madani[1] and Jay R. Lund[2]

Department of Civil and Environmental Engineering

University of California, Davis, CA 95616, USA

Phone: 530-752-5671 Fax: 530-752-7872

Email: [1]kmadani@ucdavis.edu / [2]jrlund@ucdavis.edu

Abstract

This paper presents a novel approach for modeling of high-elevation hydropower systems. Conservation of energy and energy flows (rather than water volume or mass flows) are used as the basis for modeling more than 130 high-elevation high-head hydropower sites throughout California. The unusual energy basis for reservoir modeling allows for development of hydropower operations models for a large number of plants to estimate large-scale system behavior without the expense and time needed to develop traditional streamflow and reservoir volume-based models in absence of storage capacity, penstock head, and efficacy information. Potential applications of the developed Energy-Based Hydropower Optimization Model (EBHOM) include examination of the effects of climate change and energy prices on system-wide generation and hydropower revenues.

Keywords: hydropower, high-elevation, electricity, optimization, reservoir operation, climate change, California.

1. Introduction

Hydroelectric power's low cost, near-zero pollution emissions, and ability to quickly respond to peak loads make it a valuable renewable energy source. In the mid-1990s, hydropower was about 19 percent of world's total electricity generation (Lehner et al., 2005). Worldwide hydroelectric generation from 1990 to 2020 could grow at an annual rate between 2.3 to 3.6 percent (European Commission, 2000; Lehner et al., 2005).

Depending on hydrologic conditions, hydropower provides 5 to 10 percent of the electricity used in the United States (National Energy Education Development Project, 2007) and almost 75 percent of the nation's electricity from all renewable sources (EIA, 2005; Wilbanks et al., 2007). No electricity generation source is cheaper than hydropower. While it costs almost 4 cents and 2 cents to generate one kilowatt-hour (kWh) of electricity at coal plants and nuclear plants, respectively, hydropower generation typically costs only about 1 cent per kWh (National Energy Education Development Project, 2007).

About 75,000 megawatts of hydropower generation capacity exist in the U.S., equivalent capacity to 70 large nuclear power plants (National Energy Education Development Project, 2007). More than half of U.S. hydroelectric capacity is in the western states of Washington, California and Oregon, with approximately 27 percent in Washington (EIA, 2007). Hydropower facilities in the U.S. are diverse. Facilities range from multi-purpose dams with large reservoirs to small run-of-river dams with little or no active water storage (National Energy Education Development Project, 2007). Plant elevations also vary. In California multi-purpose dams are usually at lower elevations than plants served by reservoirs operating primarily for hydropower.

California relies on hydropower for 9 to 30 percent of the electricity used in the state, depending on hydrologic conditions (Aspen Environmental Group and M. Cubed 2005). California's high-elevation hydropower system is composed of more than 150 power plants, above 305 meters (1,000 feet) elevation. This system, which mostly relies on snowpack, supplies roughly 74 percent of California's in-state hydropower, although only about 30 percent of in-state usable reservoir capacity is at high elevations, above 305 meters (Aspen Environmental Group and M. Cubed 2005). The high-elevation reservoirs are predominantly single-purpose reservoirs for generating hydropower (Aspen Environmental and M-Cubed, 2005, Vicuna et al., 2008) whith some secondary benefits such as flood control. These reservoirs which are mostly privately-owned are regulated by U.S. Federal Energy Regulatory Commission (FERC) and operated for hydropower revenues only. The high-elevation hydropower plants are generally located below small (within-year storage) reservoirs with high turbine heads compared with much larger multi-purpose reservoirs with low-turbine head downstream (lower elevations).

California's Mediterranean climate has one wet season and a long dry season. On average, 75 percent of the annual precipitation occurs between November and March. These single-purpose reservoirs (except for few such as Lake Almanor) are always emptied by the end of the hydrologic year (September) to capture fall and winter precipitation and spring snowmelt. Since electricity prices are high in summer, it is reasonable to generate and sell hydropower instead of risking energy spill in the wet season when energy prices are lower. Therefore, only one major drawdown-refill cycle per year typically occurs for hydropower and water supply operations in California.

Hydropower generation varies greatly from year to year with varying inflows, as well as competing water uses, such as flood control, water supply, recreation, and in-stream flow requirements (for water rights, navigation, and protection of fish and wildlife) (National Energy Education Development Project, 2007). Given hydropower's economic value and its role in complex water systems, it is reasonable to seek optimal operation of hydropower generation and adaptation to changing conditions. Optimization models are common for studying the performance of hydropower systems under different conditions and for deriving reservoir operating policies. Conventional simulation and optimization methods used for hydropower systems (Grygier and Stedinger, 1985; Arnold et al, 1994; Vicuna et al., 2008) are quite useful but their application to extensive hydropower systems is intensive and costly. For instance, there are 2,388 hydropower plants in the U.S., of which 411 plants are located in California (Hall and Reeves, 2006). Studying climate change effects on hydropower generation in the U.S. or even in California through conventional detailed modeling of each system requires large investments of time and money, especially when basic information such as stream flows, turbine capacities, storage operating capacities, and energy storage capacity are not readily available for each plant. Given the proprietary nature of most existing hydropower models and data, there is value for a less-detailed method of modeling extensive hydropower systems lacking detailed information. The objective of this paper is to introduce a new method for studying optimal operation of high-elevation systems, which operate predominantly for hydropower, with high head and negligible over-year storage, in absence of detailed information about the system, Energy-based modeling of single-purpose hydropower systems is presented, along with application to 137 hydropower plants throughout California. We begin with the general model formulation, followed by novel methods for estimating the energy storage capacity of hydropower units and representing hourly-varying prices in reservoir models at larger time scales. A small change in the formulation is introduced for cyclic seasonal operations. Comparison of model generation estimates is made with the historic generation in an average hydrologic year at a particular facility in California (Loon Lake). Discussion of the general estimation of parameters for 156 hydropower plants in California is made. Then the model is applied to estimate optimal monthly energy generation at 137 hydropower plants in California for a 15 year period. The paper concludes with a discussion of potential applications, limitations, and conclusions. The primary advantage of this approach is to develop policy and operational insights for large numbers of hydropower plants where traditional reservoir model development and estimation would be prohibitively costly and time consuming.

2. Energy-Based Hydropower Optimization Model (EBHOM)

Unlike conventional models, where calculations are in volumetric units, the Energy-Based Hydropower Optimization Model (EBHOM), introduced here, is a monthly-step model which does all storage, release, and flow calculations in energy units. EBHOM is developed to investigate the performance of the system under different conditions and can contribute to studies in which the active storage capacity data and penstock head information are unavailable. In such studies, energy storage capacity for each unit can be calculated based on differences in seasonal water inflow distribution and energy generation data. EBHOM can then be applied to explore the optimal operation of the system for different scenarios.

Most high-elevation hydropower plants operate for net revenue maximization (Jacobs et al., 1995). Lower elevation plants tend to operate for a greater variety of purposes. Since hydropower operating costs are essentially fixed (at monthly scale), an operational surrogate for net revenue maximization is revenue maximization. EBHOM's simple general mathematical formulation (in energy units) is:

$$\text{Maximize } Z = \sum_{i=1}^{12} P_i \times G_i \qquad (1)$$

Subject to:

$$S_1 = 0 \text{ (initial condition)} \qquad (2)$$

$$S_i \leq Scap \text{ (storage capacity)}, \forall i \qquad (3)$$

$$S_i = e_{i-1} + S_{i-1} - R_{i-1} \text{ (conservation of energy)}, \forall i \qquad (4)$$

$$G_i \leq R_i, \forall i \qquad (5)$$

$$G_i \leq Gcap \text{ (generation capacity constraint)}, \forall i \qquad (6)$$

$$G_i, S_i, R_i \geq 0 \text{ (non-negativity)}, \forall i \qquad (7)$$

$$(i = 1, 2, 3, \ldots, 12)$$

where Z = revenue; G_i = hydropower generation in month i (MWh/month); P_i = price of electricity in month i (\$/MWh); S_i = energy storage at the beginning of month i (MWh); $Scap$ = energy storage capacity (MWh); e_i = energy runoff in month i (MWh); R_i = energy release from the reservoir in month i (MWh/month) (decision variable); $Gcap$ = generation capacity

(MWh/month); and $i = 1$ corresponds to the first month of the refill cycle with energy storage at the beginning of this month set equal to zero (Equation 2).

This formulation is valid when the reservoir is used only for hydropower generation, and primarily for seasonal (as opposed to over-year) storage. The formulation also requires a "high-head" condition where storage does not significantly affect hydropower head.

3. Estimating Seasonal Energy Storage Capacity

Normal estimation of a reservoir's energy storage capacity involves integrating the potential energy content over all reservoir elevations, presuming detailed knowledge of penstocks, reservoir geometries, and bank storage. Obtaining storage capacity data and penstock head information for many individual reservoirs is a big obstacle in large-scale hydropower systems modeling, especially if they belong to private owners with proprietary interests in information. Even if volumetric storage capacities were available, conventional estimation of energy storage capacities (that portion of the capacity storing water for electricity generation) would have been tedious and probably unreliable. To estimate the energy storage capacity of each power plant, it is assumed that the existing storage and release capacities of a high-elevation hydropower reservoir are sufficient to operationally accommodate the historical runoff in an average water year without water spilling from the reservoir.

The proposed No Spill Method (NSM) estimates seasonal energy storage capacity under the following conditions:

1. The reservoir does not spill energy in the average year, and all releases are made through the turbines. Energy spill results from runoff lost from the system because it can be neither stored nor sent through the turbines due to limited storage and turbine capacities. Energy spill is the equivalent energy value of the available runoff which cannot contribute to energy production at a site. For California, this lack of spill in an average year was confirmed in conversations with the private hydropower operators of most high-elevation plants in California. This condition sets a lower bound for storage capacity estimation. Actual reservoir capacity will exceed this lower bound if the reservoir does not fill in an average year. However, for calculation purposes it is assumed that the reservoir fills in an average year. This makes the approach pessimistic.

2. The power plant is a high-head facility, where the effect of reservoir storage level on turbine head is small. Generally, turbine head in high-elevation hydropower facilities is mostly from large penstock drops, rather than additional elevation within the reservoir. This allows a linear relationship between the amount of water stored in the reservoir and energy stored, and seems common for many proprietary models for this system.

3. The seasonal distribution of inflow is known. Average seasonal flow distributions from nearby gages are used here to reflect seasonal runoff and snowmelt conditions.

4. There is only one major drawdown-refill cycle per year. Hydropower reservoirs typically fill once each year in California.

High-elevation hydropower facilities usually have a within-year storage pool and mostly have watersheds above 305 meters 1,000 feet. In California, many of these systems rely on snowpack to increase the seasonal storage of the system.

The NSM estimates seasonal storage capacity in energy units by finding the area between the monthly runoff and monthly generation curves when both are expressed as monthly percentages of the annual average quantity. In month *i*, the runoff percentage (*runoffPercent*$_i$) and generation percentage (*genPercent*$_i$) can be calculated by dividing the average monthly runoff in month i (*average runoff*$_i$) and the average monthly generation in month *i* (*average generation*$_i$) to the average annual runoff (*average annual runoff*) and the average annual generation (*average annual runoff*), respectively.

$$runoffPercent_i = \frac{average\ runoff_i}{average\ annual\ runoff} \tag{8}$$

$$genPercent(i) = \frac{average\ generation(i)}{average\ annual\ generation} \tag{9}$$

In percentage terms, the sum of differences between the two curves for a year (12 months) should be zero.

$$\sum_{i=1}^{12}(runoffPercent_i - genPercent_i) = 0 \tag{10}$$

In the 12 month period there are months *i* when the runoff percentage exceeds the generation percentage value (when some runoff is stored in the reservoir) and months *j* when the generation percentage exceeds the runoff percentage (when some hydropower is generated by releasing stored water).

$$\sum_i(runoffPercent_i - genPercent_i) - \sum_j(genPercent_j - runoffPercent_j) = 0 \tag{11}$$

So, if there is only one refill-drawdown cycle per year, little over-year storage, and the reservoir is on the verge of spilling at its fullest, the seasonal storage capacity (*StorCapPercent*) as a percent of total inflow is (Figure 1):

$$StorCapPercent = \sum_i (runPercent_i - genPercent_i) \qquad (12)$$

or:

$$StorCapPercent = \sum_j (genPercent_j - runoffPercent_j) \qquad (13)$$

Multiplying the storage capacity percentage (*StorCapPercent*) by the average annual generation gives the active (operational) energy storage capacity (*Scap*).

$$Scap = StorCapPercent \times average\ annual\ generation \qquad (14)$$

Multiplying the storage capacity percentage by the average annual runoff gives the volumetric active (operational) water storage capacity (WScap) which is directly used for hydropower generation.

$$WScap = StorCapPercent \times average\ annual\ runoff \qquad (15)$$

Significantly, this method produces a lower bound estimate of energy storage capacity, as many reservoirs will not spill or fill in wetter than average years. The NSM also assumes reservoirs have negligible over-year storage, which is true for high-elevation hydropower reservoirs in California with a few exceptions (such as Lake Almanor in California).

Figure 1 shows how the active storage capacity of the Buck Island (also known as Rubicon or Loon Lake) Reservoir, with the storage capacity of 96 million cubic meters (mcm) (or 78 Thousand Acre-Feet (TAF)), located above Loon Lake Hydropower Plant with generation capacity of 38 GWh per month and Average Annual Generation of 104 GWh in California was estimated using NSM. Monthly generation data was available for the years 1984 to 1998. Monthly runoff (inflow) data was obtained for the same period from U.S. Geological Survey (USGS) gauges. The mean monthly and mean annual runoffs were estimated for the study period. Mean monthly runoff and mean monthly generation values were then normalized into percent of mean annual runoff (Equation 8) and mean annual generation (Equation 9), respectively, as shown in Figure 1. Based on Equation 12 or 13, the shaded area between the two curves (29 percent) represents the storage capacity as a percentage of total generation or flow (*StorCapPercent*). Active storage capacity of this reservoir (the portion of actual energy storage capacity used for storing water for hydropower) was found to be 31 GWh based on Equation 14 and 13.6 mcm (11 TAF) based on Equation 15.

At a monthly time scale, several stair-stepped power houses (in series) might benefit from water storage in one upstream reservoir. When one powerplant draws water from several upstream reservoirs (in parallel or series) the energy storage calculated for the powerplant will reflect the total effective energy storage upstream of the plant. For instance for 2 reservoirs in series, the effective storage capacity belonging to the power station located below the second (lower) reservoir is determined based on the difference between the undisturbed (natural) runoff to the first reservoir and the energy outflow from the second powerplant. In that case, the calculated storage capacity is equal to the effective storage capacity of the lower reservoir plus the portion effective storage capacity of the upper reservoir used for regulating the inflow to the lower reservoir. Indeed, in this case the difference between the runoff and generation curves could be smaller if there was no up-stream reservoir. However, when an upstream reservoir exists, energy is stored in the upper reservoir for some period, so the total effective storage capacity is higher than the effective storage capacity of the lower reservoir. This can become a more complicated issue, as inflows for downstream powerplants might be dominated by releases from upstream plants, not the assumed monthly inflow distribution for the powerplant. Ultimately, this is one of the limitations of such coarse less-detailed modeling. Incorporating such effects would require much greater modeling effort, which we needed to avoid here.

4. Energy Price Representation

If fixed monthly energy prices are used in Equation 1, EBHOM is linear as done in studies by Vicuna et al. (2008), and Madani and Lund (2007). However, if fixed monthly energy prices are used, while maximizing revenue, the model suggests no generation in months with low energy prices to allow more generation in months with higher average prices, within storage capacity limits (Madani and Lund, 2007). In real electricity markets, prices fluctuate hourly and marginal revenues of generation decrease with increased hours of generation. Linear EBHOM (monthly basis model) does not capture the varying nature of energy prices and the considerable effects of on-peak and off-peak pricing on the revenues. Considering on-peak and off-peak monthly prices in the linear model (Vicuna et al., 2008) captures some effects of non-constant energy prices. It is possible to capture the varying nature of energy prices by linear EBHOM if it is formulated on an hourly basis. However, such a model takes much more time as it requires 730 times more decision variables (with 730 hours in average month). To decrease calculation time and effort, EBHOM can be formulated on a monthly basis as a concave non-linear problem to represent on-peak and off-peak price variability, with a revised objective function (Equation 1) as follows:

$$\text{Maximize } Z = \sum_{i=1}^{12} P_i(h_i) \times G_i \qquad (16)$$

where average monthly energy price $P(h_i)$ is a function of total hours of generation in month i. The variation in price with generation is not a result of price effects from an individual power plant's generation. Instead, this price variation represents the hourly variability in energy prices of the overall energy market responding mostly to on-peak and off-peak variability in energy demands. Price for an individual plant's operation varies with the number of hours it operates. Since these plants are run to maximize power revenues, they are assumed to be operated in hours when the energy market offers higher prices.

If a plant operation is solely for hydropower, then the frequency distribution of hourly hydropower prices (Figure 2) can be integrated into an average revenue function of turbine release as a percent of monthly turbine capacity (Figure 3). If operating only for hydropower, a utility will release first at high-valued times and only release at lower-valued times as water becomes more abundant. The resulting benefit function allows approximate representation of hourly pricing within a monthly model. Hourly price frequencies from 2005 are used to develop revenue functions for each month (the 2005 prices were used only because of unavailability of price data for earlier years). Figure 2 shows the frequency of real-time market hourly energy prices in October 2005 in California, spanning on-peak and off-peak prices. For optimal hydropower operations, average energy price declines as hours of generation increase, so small releases are targeted for the maximum energy price and lowest average price occurs when release equals generation capacity. Since monthly generation increases by increasing the hours of turbine-run, it is assumed that the revenue from each hydropower plant is a function of the portion of used monthly generation capacity:

$$z_i(h_i) = z_i(g_i) \qquad (18)$$

where: g_i is the portion of monthly generation capacity used.

$$g_i = \frac{G_i}{Gcap} \qquad (19)$$

Integration over the price curve in a given month (Figure 2) gives that month's revenue (z_i) as follows:

$$z_i(g_i) = Gcap.\int_0^{g_i} P_i(g_i)dg_i \qquad (20)$$

Using Equation 20, concave revenue curves for each month (October in this example) can be derived, as shown in Figure 3. In this figure, the horizontal axis shows g_i (October), and the vertical axis shows the corresponding average revenue per unit of plant generation capacity $(\frac{z_i(g_i)}{Gcap})$. From Figure 3, if the power plant generates at its full capacity in October, revenue at that power plant is 48 $/MWh times its generation capacity. Revenue curves for any given fixed-head Californian hydropower plant in each month can be derived by multiplying both axes of Figure 3 by generation capacity of that power plant. Such curves can then be piece-wise linearized or included non-linearly, and summed over the months for the objective function of EBHOM (Equation 16 as follows):

$$Maximize\ Z = \sum_{i=1}^{12} z_i(g_i) \qquad (21)$$

This formulation reflects the on-peak on off-peak pricing. The prices occur for the same hours of the day, across all plants. The price does not decrease because of the quantity of energy generated, but because of the hours of the day generated.

5. Reformulation for Cyclical Operations

The EBHOM, as defined earlier, can be sensitive to the initial storage condition (Equation 2). Each reservoir has a specific refill and drawdown cycle. To find the best initial condition (refill month) for a single reservoir, the EBHOM should be run 12 times for the 12 different possible refill months, saving the decision values from the best performing refill month.

Although simple and comprehensible, running the model 12 times for each reservoir requires excessive computation time for large systems. To decrease the calculation time the formulation is revised by replacing the first two constraints (Equations 2 and 3) with the following four constraints:

$$S_1 = big \text{ (initial condition)} \qquad (22)$$

$$S_{min} \leq S_i, \ \forall i \qquad (23)$$

$$S_i \leq S_{max}, \ \forall i \qquad (24)$$

$$S_{max} - S_{min} \leq Scap \text{ (storage capacity constraint)} \qquad (25)$$

where big = an arbitrary large number greater than or equal to *Scap*; S_{min} = minimum monthly energy storage during the year (12 months period) (a decision variable); and S_{max} = maximum monthly energy storage during the year (a decision variable).

This formulation sets initial storage equal to a large nominal level (*big*). Storage changes are then made conventionally around this nominal level, with storage constrained to return to this initial level. The storage capacity constraint is enforced by defining the minimum and maximum storages from all months (Equations 23 and 24), and then constraining the difference (Equation 25), which is the amplitude of the annual drawdown-refill cycle. This limits real storage within the real storage capacity. Since the nominal initial storage exceeds the reservoir's capacity, nominal storage cannot be negative in any month.

6. Comparison for Loon Lake Power Plant

Figure 4 compares the average historic (recorded) hydropower generation (period 1982-2002) and the EBHOM's estimation of optimal monthly hydropower generation in an average hydrologic year of the same period at Loon Lake Hydropower Plant, which belongs to the Sacramento Municipal Utility District (SMUD) reservoir system. Assuming a fixed energy head, un-regulated water runoff is linearly related to available energy runoff. Based on the No-Spill assumption, total annual energy generation for a given hydropower plant (from observed energy generation data) in a given year equals the annual available energy runoff at its location in that year, and only the seasonal distributions differ. Accordingly, monthly distribution of energy runoff in each year of the study period was assumed to be exactly the same as the distribution of mean monthly runoff for the period 1928 to 1949. Monthly energy runoff was computed (for use in Equation 4) based on the monthly runoff distribution given by the hydrologic record where annual energy runoff equals the annual hydropower generation. Monthly revenue curves were based on information from California Independent System Operator Open Access Same-Time Information System Web Site for the year 2005 (California ISO OASIS, 2007). The non-linear optimization problem was solved by linear programming through piecewise linearization of the concave revenue function.

Generally, the difference of historic and modeled values is due to the mismatching runoff, hydropower generation, and price data sets used, and non-energy hydropower operations such as maintaining spinning reserves. The summer generation peak found by the model (in September) is due to the high price of energy in September in the data set, which might not be true for the period 1982 to 2002. Often hydropower generators pre-sell their power through long-term contracts with fixed prices and control only that portion of hydropower generation not already sold. A more extensive comparison of the EBHOM with a traditional hydropower optimization model of the Sacramento Municipal Utility District (SMUD) reservoir system produced similar results and showed good reliability of EBHOM predictions (Madani et al., 2008).

8. Estimation for 137 Plants in California

EBHOM was applied for modeling the high-elevation hydropower system in California. One hundred fifty-six (156) high-elevation (above 305 meters or 1,000 feet) hydropower plants in California were identified. Monthly hydropower energy generation information from U.S. Energy Information Administration Databases for the period 1982 to 2002 was used to estimate the average monthly hydropower energy generation and the generation capacity of each power plant. Instead of using the name-plant capacity of each hydropower plant in this study, the maximum actual monthly generation over the 1982-2002 period was used as the monthly generation capacity. For estimating energy storage capacity available for each hydropower unit, mean monthly generation and mean annual generation were estimated. Mean monthly values were then normalized into percent of mean annual generation (Equation 9) to characterize the average seasonal distribution of energy generation at each unit. Since runoff patterns vary by elevation, three elevation ranges are considered (305-710 meters or 1,000-2000 feet, 710-915 meters or 2000-3000 feet, and above 915 meters or 3000 feet). Monthly runoff data for the study period were obtained for several USGS gauges representing these elevation ranges, selected in consultation with the former California Department of Water Resources (DWR) chief hydrologist. For each elevation range, mean monthly and mean annual runoffs were estimated. Mean monthly values were then normalized into percent of mean annual runoff (Equation 8) to characterize the average seasonal distribution of available water runoff for each elevation range. Energy storage capacity of each unit was then estimated using the NSM. Real time hourly hydroelectricity prices were obtained from the California ISO OASIS for the year 2005 (California ISO OASIS, 2007) and used to derive convex monthly revenue curves.

EBHOM was used to estimate the optimal historic monthly generation. The EBHOM for each plant was solved in Microsoft Excel (through piecewise linearization) with "What'sBest", a commercial solver package for Microsoft Excel. With the cyclic EBHOM formulation, each run for one reservoir for each year under a given hydrology takes 3 to 4 seconds. Historical generation data was complete for 137 high-elevation plants for the period of 1984-1998. The piecewise-linear optimization model was run for each year to find revenue-maximizing monthly reservoir storage and energy generation for these 137 power plants. The model was run with the historical hydrology. Assuming no over-year storage, release decisions in each year are independent. Figure 5 shows the range of the estimated energy storage and generation capacities of the studied high-elevation hydropower plants. The annual energy storage capacities of most of the studied power plants are at least 1.3 times larger than their monthly generation capacity, which provides some flexibility in operations. For most power plants, energy storage capacity exceeds one month of generation capacity.

Figure 6 shows the historical and modeled average energy generation of 137 hydropower plants for the period 1984 to 1998. (The analysis has not been done for an average year but for 15 years of hydrologic (energy inflow) annual variability, spanning dry, wet, and average years. The results are reported as average over the 15 year period for which 15 model runs were required). The optimized generation for the historic climate differs from historic observations (the dashed curve in Figure 6). Differences arise from a variety of factors, including non-hydropower operating factors, differences in hydropower prices from the recorded years, non-energy hydropower operations such as spinning reserves, and the foresight of the model regarding incoming flows during the year. Another reason for divergence between the EBHOM's results and the observed generation is application of a representative annual hydrograph for each elevation band rather than locally measured inflows for each year. The generation results are highly price driven and follow the California ISO energy price trends in 2005.

Figure 7 shows the average end-of-month energy storage in all reservoirs combined in the study period for operations optimized for hydropower. EBHOM suggests that reservoirs reach their minimum storage level by the end of January in preparation to capture inflow from winter precipitation and spring snowmelt. On average, reservoirs are full by June and gradually empty for energy generation over summer when energy prices are higher and there is little natural inflow. Under historical conditions, refill starts in February and drawdown starts in July.

Figure 8 indicates the average shadow prices of energy storage and generation capacities (the average increase in annual revenue per unit of capacity expansion) for all 137 reservoirs for the study period. This figure shows the average increase in annual revenue (y-axis) per MWh energy storage/generation capacity expansion for corresponding number of power plants (x-axis). For instance, increase in annual revenue is less than $10 revenue per MWh energy storage capacity expansion for 50 of the studied power plants. Generally, storage capacity expansion is more beneficial than generation capacity expansion. Water can be stored in the reservoir in low-value months to be released in summer when energy prices are higher. Thus, shadow price of energy storage capacity always exceeds the shadow price of generation capacity for all the reservoirs. Generation capacity expansion does not increase average revenue of about 90 hydropower plants while energy storage capacity expansion always increases annual revenues. Although expansion of storage and generation capacities can increase average annual revenues, expansions might not be justified due to expansion costs. In some cases, where hydropower plants are in series and draw on the same upstream reservoir, the value of expanding that reservoir would be the sum of storage expansion values for all downstream plants. Since the NSM (No-Spill Method) tends to underestimate energy storage capacities, the values for storage capacity expansion are probably high estimates.

9. EBHOM Applications

Generally, an EBHOM can be applied in any hydropower system operation study where there is relatively little effect of storage on head and there is an interest in the big picture of the system and details are of lesser importance (e.g. large-scale policy, preliminary planning, and adaptation studies). Some potential applications are discussed below.

Climate warming is a hydropower concern in regions with significant snowmelt runoff, such as California. High-elevation hydropower systems in California rely on snowpack for seasonal storage of precipitation, which makes those systems more vulnerable to climate warming (Vicuna et al., 2008; Madani and Lund, 2007). EBHOM is convenient for studying climate change effects on large-scale hydropower systems. Monthly runoff (energy inflow) can be perturbed for various climate change scenarios. The effects of several climate scenarios can be calculated quickly to allow quick, broad system-scale studies to accompany narrower conventional hydropower optimization studies (Vicuna et al., 2008).

Effects of energy demand/pricing changes on hydropower generation and resulting downstream flows also can be studied using EBHOM. Greater energy demand increases energy prices. Currently, electricity is more expensive in summer and winter months from cooling and heating. Energy demand can change for various climatic, economic, technologic, policy, or market reasons. Climate warming also can reduce winter energy demand and prices (for heating) and increase demand and prices in summer (for cooling). Energy prices also might change from changes in supply. For instance, more energy generation in early spring from earlier snowmelt might reduce energy prices in that period. Energy prices also can change with long-term changes in energy-use technologies (e.g. for heating and cooling), economic growth, energy market conditions (availability of non-hydropower energy supplies), energy conservation, or energy regulatory policies. The effects of changes in energy prices on hydropower generation can be studied conveniently by developing representative revenue curves (similar to Figure 3) for conditions of interest.

In some parts of the world, large-scale expansions of hydropower storage and generation are being contemplated. EBHOM formulations can be used to preliminary explore and identify promising types and locations of power plant expansions, employing the Lagrange multiplier (shadow price) results for energy storage and generation capacity constraints.

A final application of this type of coarse model might be for seasonal energy production and market studies and forecasts. A coarse EBHOM can quickly give seasonal energy planners and schedulers insights into when and how much hydropower is likely to be produced over a coarse seasonal horizon, although operators are likely to have access to more detailed proprietary models.

5. Limitations

The No-Spill Method (NSM) for estimating energy storage capacity should be applied to the systems where there is little or no spill in many years and there is little over-year storage. Nevertheless, the NSM will tend to under-estimate storage capacities and therefore also underestimate the adaptability of the hydropower system to hydrologic and economic conditions. More detailed studies could provide better estimates of energy storage capacities.

For this application to California, we assume that inflow distributions adhere to a fixed seasonal pattern, which seem reasonable for California's Mediterranean climate. This EBHOM is formulated without considering environmental flows. Environmental constraints sometimes restrict the flexibility of operations and introduce trade-offs between hydropower generation revenues and ecosystem conservation benefits. These tend to be less for high-elevation reservoirs, but will probably increase with time. Environmental constraints could be incorporated in the model as minimum releases or as changes in the objective function or the frequency distribution of prices.

EBHOM is a deterministic model and optimizes generation based on perfect foresight for seasonal inflows and the frequency distribution of prices. Such management is impossible in practice, because of imperfectability of forecasts of hydrologic and price conditions. Long-term generation contracts also will affect operations.

6. Conclusions

This study introduced an innovative approach for exploring the performance of high-elevation hydropower systems without detailed information on volumetric storage capacity, inflow, or geometric configuration. Estimation of energy storage capacity is made based on seasonal shifts of energy inflows to generation, energy inflows are based on seasonal inflow distributions, and generation capacity is estimated from maximum observed generation rates.

The goal of this study was to explore an approach for studying extensive multi-facility high-head hydropower systems with minimal available information and efficient. This approach is used to represent 137 high-elevation (high-head) units in California. The method required some simplifying assumptions. EBHOM can be applied in high-elevation hydropower operation studies examining climate change effects and adaptations for hydropower generation, the effects of electricity demand and pricing changes on hydropower generation, early planning for extensive capacity expansions, and seasonal energy forecast and scheduling studies.

The contributions of this work are:

1. An energy-unit based model (Energy-Based Hydropower Optimization Model or EBHOM) of single-purpose hydropower generation systems, requiring little model development effort for low-detailed modeling.
2. The No-Spill Method (NSM) for estimating energy storage capacity.
3. A price-frequency method of better representing hourly energy prices in models with larger time steps.
4. A cyclic storage formulation to decrease the calculation time and cost.
5. A simple approach for developing a good representation of an extensive system with little time or resources for policy and adaptation studies for various purposes.

Acknowledgements

The authors thank Omid Rouhani from University of California, Davis for his help in EBHOM development, Marcelo Olivares from University of California, Davis for hourly energy price data, Sebastian Vicuna from University of California, Berkeley for the historical runoff data and other information for the Loon Lake Hydropower Plant, Maury Roos from California Department of Water Recourses for the names of reliable high-elevation gauges in California, Jery Stedinger from Cornell University for his early feed-back on the work, and Rolf Larsson from Lund University and the anonymous reviewers for their constructive comments. This work was funded by the California Energy Commission's Public Interest Energy Research (PIER) program and the Resources Legacy Fund Foundation.

References

Arnold E., P. Tatjewski, and P. Wolochowicz (1994) Two methods for large-scale nonlinear optimization and their comparison on a case study of hydropower optimization, *J. of Optimiz. Theory App*, 81 (2), 221-248.

California ISO OASIS (2007) Hourly Average Energy Prices, California Independent System Operator (ISO) Open Access Same-Time Information System (OASIS) web site, http://oasis.caiso.com/ (May 2007).

EIA (2005) Renewable Energy Trends 2004, Table 18, Renewable Electric Power Sector Net Generation by Energy Source and State, 2003, Energy Information Administration, Washington, DC.

Energy Information Administration (2007) Energy Kid's Page available at: http://www.eia.doe.gov/kids/energyfacts/sources/renewable/water.html, November 6, 2007

European Commission (2000) 1999 annual energy review, *Energy in Europe special issue—January 2000*, Directorate-General for Energy, Brussels, ISBN 92-828-7448-6.

Grygier, J.C. and J.R. Stedinger (1985) Algorithms for Optimizing Hydropower System Operation, *Water Resour. Res.*, *21*, 1-10.

Hall D. G. and K. Reeves (2006) A Study of United States Hydroelectric Plant Ownership, *Report prepared for the National Renewable Energy Laboratory*, Idaho National Laboratory, INL/EXT-06-11519.

Jacobs J., Freeman G., Grygier J., Morton D., Schultz G., Staschus K., and Stedinger J. (1995) SOCRATES: A system for scheduling hydroelectric generation under uncertainty, *Annals of Operations Research*, 59 (1), 99-133.

Lehner B., G. Czischb, and S. Vassolo (2005) The impact of global change on the hydropower potential of Europe: a model-based analysis, *Energ. Policy (33)*, 839–855.

Madani K. and J. R, Lund (2007) High-Elevation Hydropower and Climate Warming in California, *Proceeding of the 2007 World Environmental and Water Resources Congress, Tampa, Florida*, (Ed) Kabbes K. C., ASCE.

Madani K., S. Vicuna, J. Lund, J. Dracup, and L. Dale (2008) Different Approaches to Study the Adaptability of High-Elevation Hydropower Systems to Climate Change: The Case of SMUD's Upper American River Project", *Proceeding of the 2008 World Environmental and Water Resources Congress, Honolulu, Hawaii*, (Ed) Babcock R. W. and Walton R., ASCE.

National Energy Education and Development Project (2007) Hydropower, *Secondary Info Book*, pp. 24-27.

Vicuna S., R. Leonardson, M. W. Hanemann, L. L. Dale, and J. A. Dracup (2008) Climate change impacts on high elevation hydropower generation in California's Sierra Nevada: a case study in the Upper American River, *Climatic Change*, 28 (Supplement 1), 123-137.

Wilbanks T. J., T. Bhatt, D. E. Bilello, S. R. Bull, J. Ekmann, W. C. Horak, Y. J. Huang, M. D. Levine, M. J. Sale, D. K. Schmalzer, and M. J. Scott (2007) Effects of Climate Change on Energy Production and Use in the United States, *Synthesis and Assessment Product 4.5, Report by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research*, October 2007.

Figure Captions

Figure 1- Calculation of operational storage capacity of Loon Lake Reservoir based on NSM. The shaded area between the two curves stands for the storage capacity of the reservoir in percentage terms.

Figure 2. Frequency of California's hourly hydroelectricity price in October 2005 (California ISO OASIS, 2007)

Figure 3. Revenue-generation correlation in October 2005 (California ISO OASIS, 2007)

Figure 4- Comparison of average historic monthly electricity generation and optimal monthly electricity generation (found by EBHOM) at Loon Lake Hydropower Plant in California

Figure 5. Comparison of historic average monthly electricity generation and optimal average monthly electricity generation (found by EBHOM) of 137 hydropower units in California in the 1984-1998 period

Figure 6. Comparison of historic average monthly electricity generation and optimal average monthly electricity generation (found by EBHOM) of 137 hydropower units in California in the 1984-1998 period

Figure 7. Average modeled total end-of-month energy storage (found by EBHOM) of 137 hydropower units in California in the 1984-1998 period

Figure 8. Average shadow prices of monthly energy generation and energy storage capacities (found by EBHOM) of 137 hydropower units for California in the 1984-1998 period

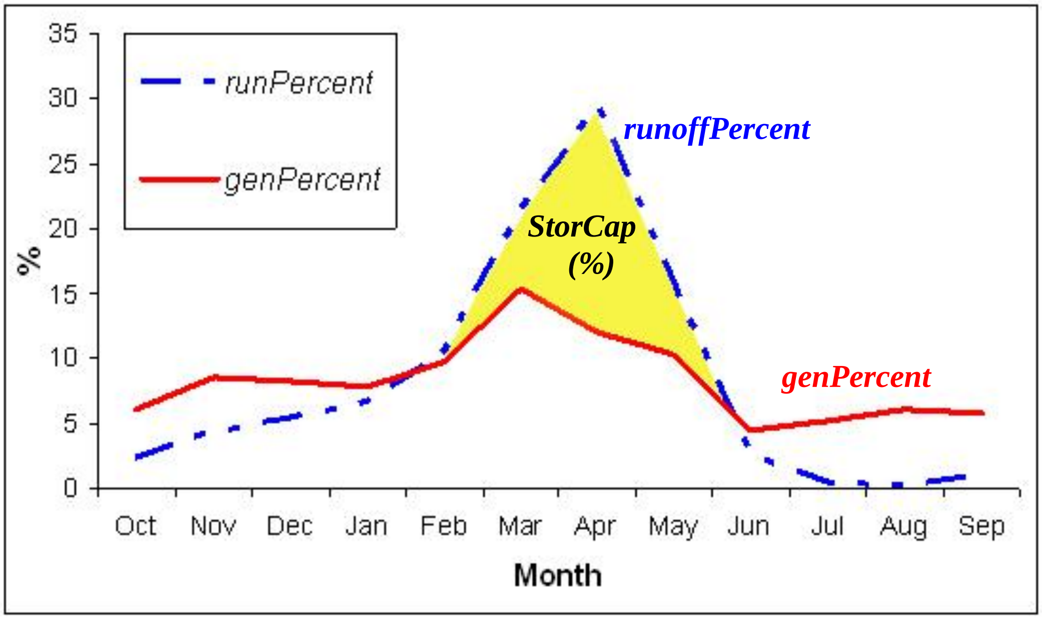


Figure 1- Calculation of operational storage capacity of Loon Lake Reservoir based on NSM. The shaded area between the two curves stands for the storage capacity of the reservoir in percentage terms.

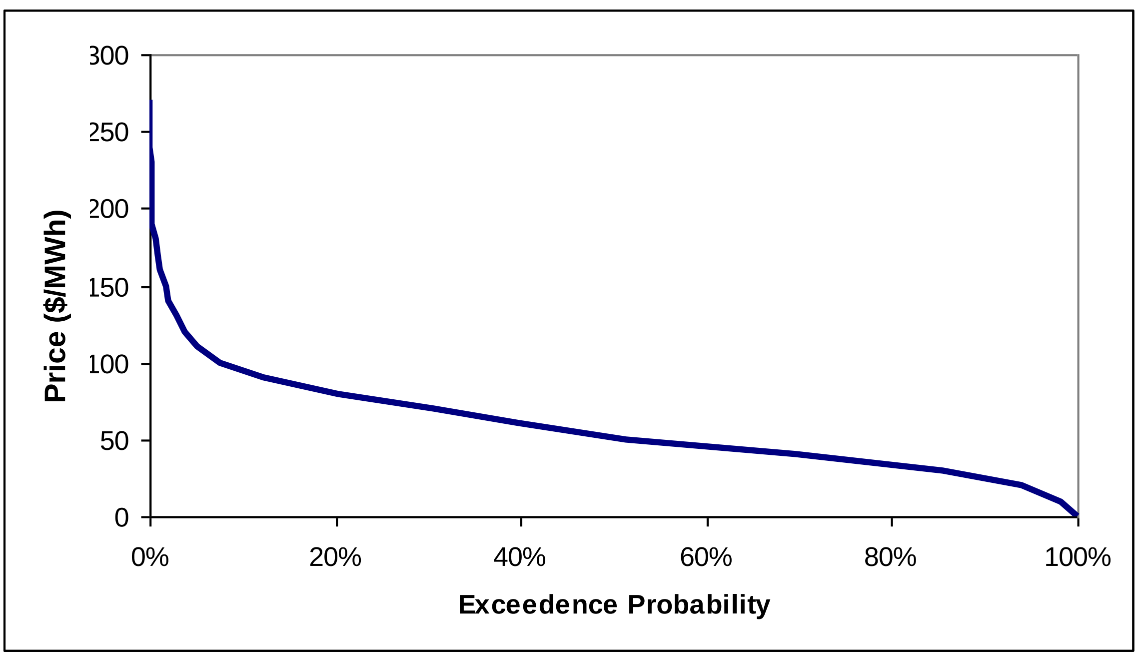


Figure 2. Frequency of California's hourly hydroelectricity price in October 2005 (California ISO OASIS, 2007)

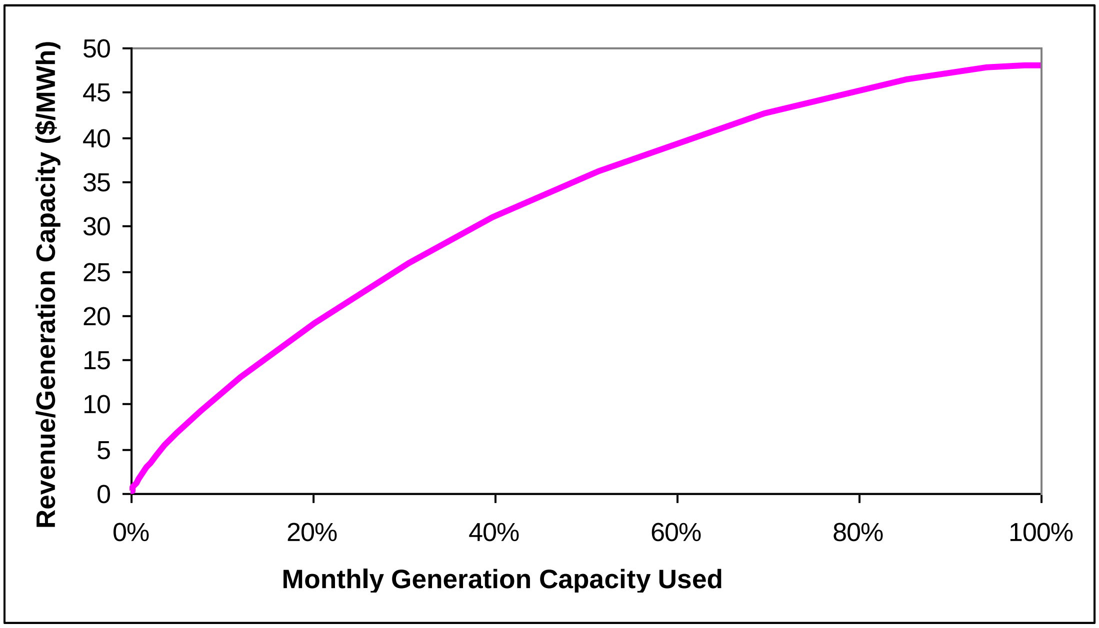


Figure 3. Revenue-generation correlation in October 2005 (California ISO OASIS, 2007). Vertical axis shows the average revenue (in $) per unit of plant generation capacity (in MWh).

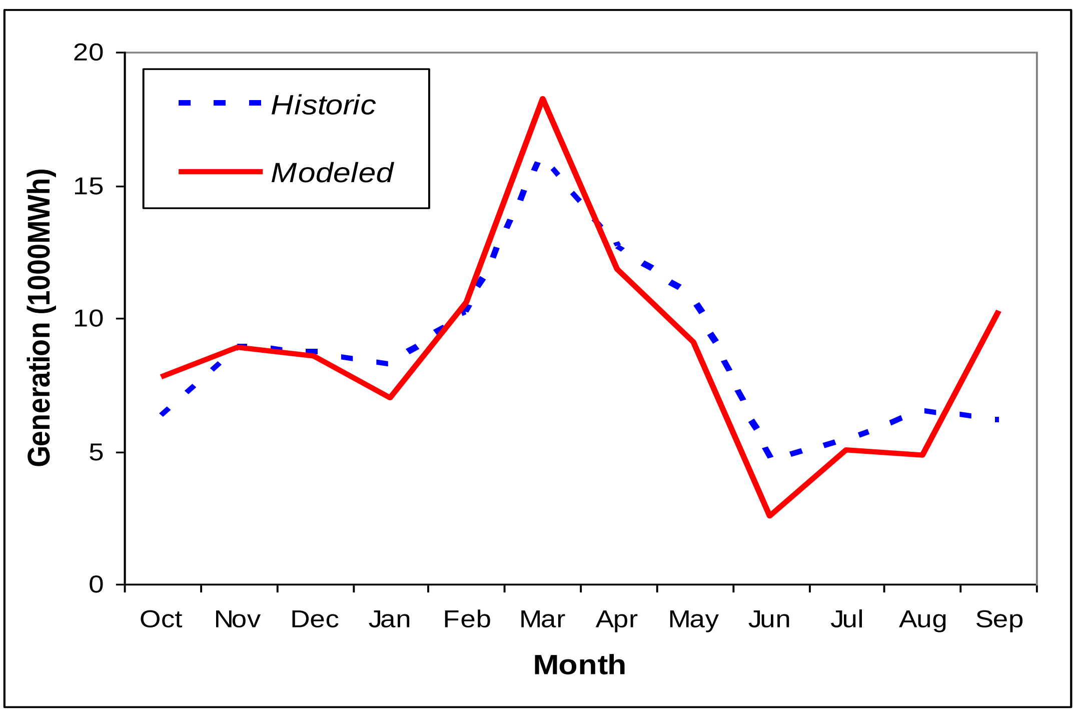


Figure 4 - Comparison of average historic monthly electricity generation and optimal monthly electricity generation (found by EBHOM) at Loon Lake Hydropower Plant in California

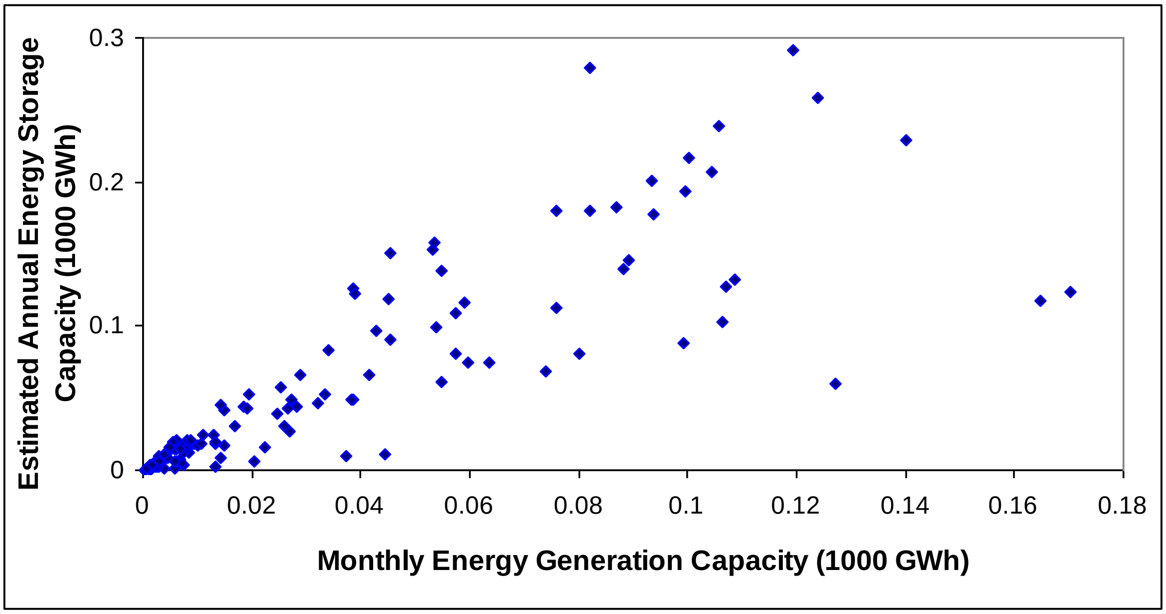


Figure 5. Range of the estimated energy storage and generation capacities of the 137 studied high-elevation hydropower plants in California

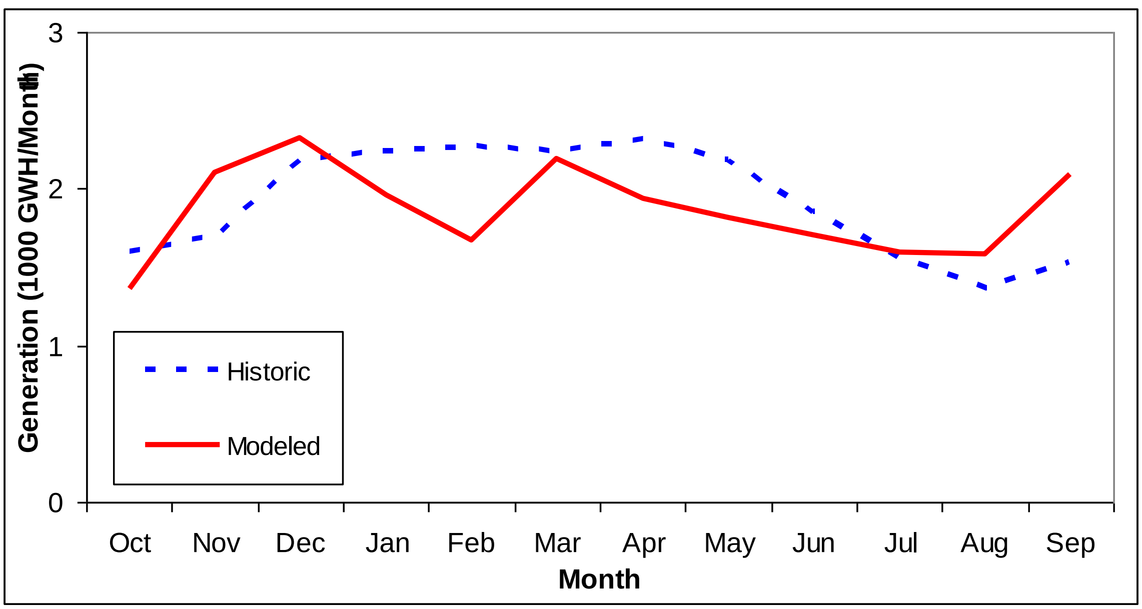


Figure 6. Comparison of historic average monthly electricity generation and optimal average monthly electricity generation (found by EBHOM) of 137 hydropower units in California in the 1984-1998 period

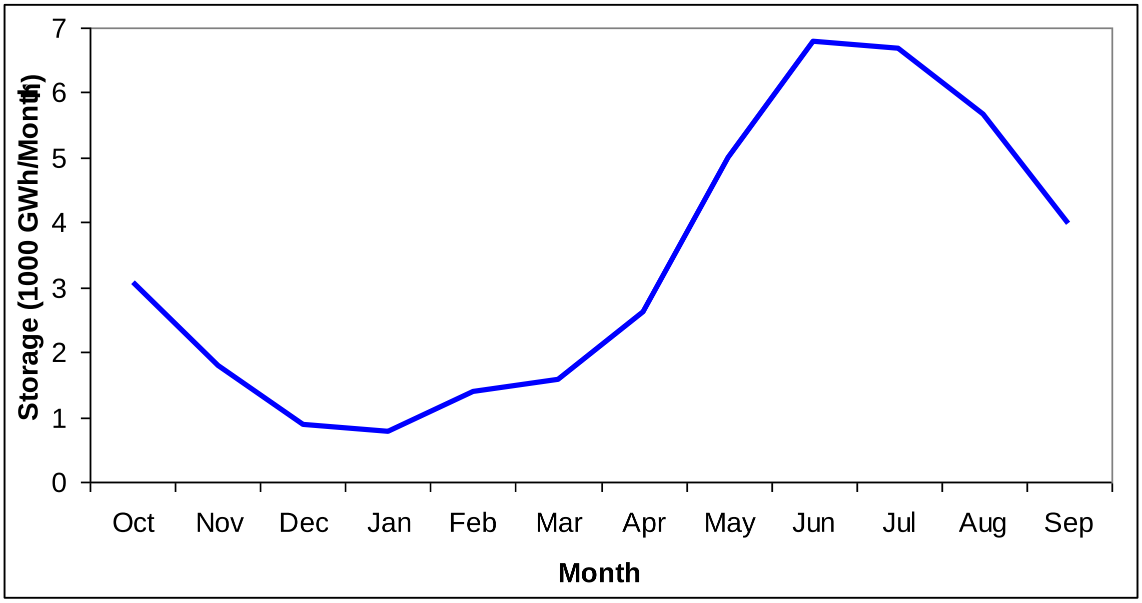


Figure 7. Average modeled total end-of-month energy storage (found by EBHOM) of 137 hydropower units in California in the 1984-1998 period

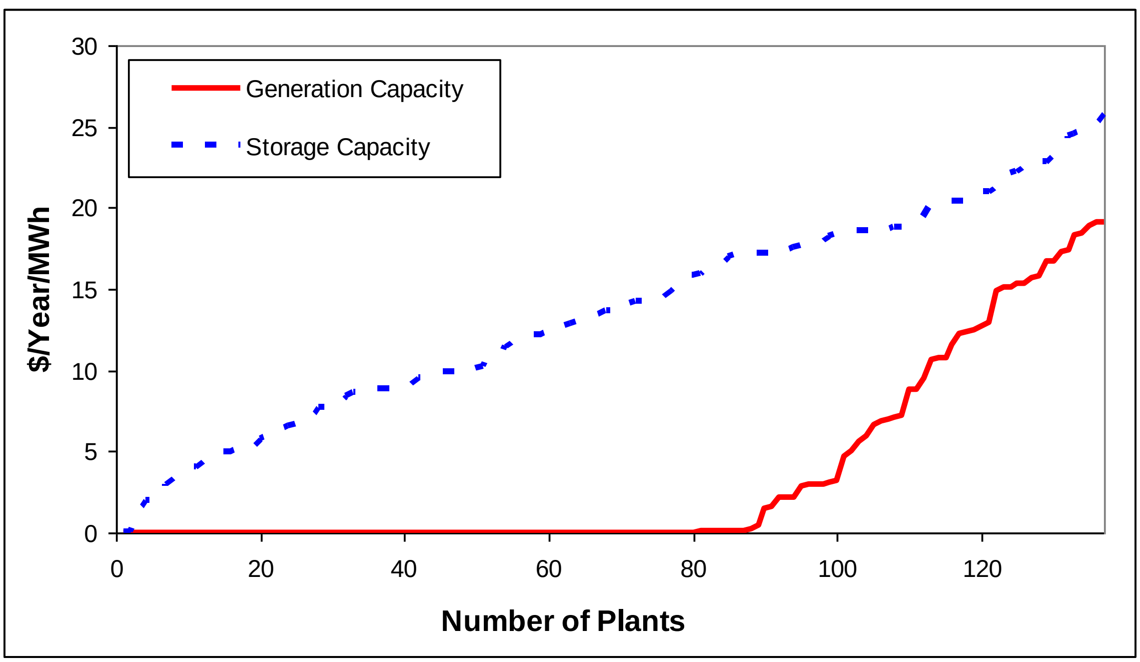


Figure 8. Average shadow prices of monthly energy generation and energy storage capacities (found by EBHOM) of 137 hydropower units for California in the 1984-1998 period