Climate Change Effects on High-Elevation Hydropower System in California

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Abstract

The high-elevation hydropower system in California, composed of more than 150 hydropower plants and regulated by the Federal Energy Regulatory Commission (FERC), supplies 74 percent of in-state hydropower. The system has modest reservoir capacities and has been designed to take advantage of snowpack. The expected shift of runoff peak from spring to winter as a result of climate warming, resulting in snowpack reduction and earlier snowmelt, might have important effects on hydropower operations. Estimation of climate warming effects on such a large system by conventional simulation or optimization methods would be tedious and expensive. This dissertation presents a novel approach for modeling large hydropower systems. Conservation of energy and energy flows are used as the basis for modeling high-elevation high-head hydropower systems in California. The unusual energy basis for reservoir modeling allows for development of hydropower operations models 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 and release capacity, penstock head, and efficiency information. An Energy-Based Hydropower Optimization Model (EBHOM) is developed to facilitate a practical climate change study based on the historical generation data high-elevation hydropower plants in California. Employing recent historical hourly energy prices, energy generation in California is explored for three climate warming scenarios (dry warming, wet warming, and warming-only) over 14 years, representing a range of hydrologic conditions. Currently, the high-elevation hydropower plants in California have to renew their FERC licenses. A method based on cooperative game theory is developed to explore FERC relicensing process, in which dam owners negotiate over the available instream water with other interest groups downstream. It is discussed how the lack of incentive for cooperation results in long delay in FERC relicensing in practice and argued how climate change may provide an incentive for cooperation among the parties to hasten the relicensing. An "adaptive FERC license" framework is proposed, to improve the performance and adaptability of the system to future changes with no cost to the FERC, in face of uncertainty about future hydrological and ecological conditions.

Keywords

Hydropower, Climate Change, Energy-Based Optimization Model (EBHOM), No-Spill Method (NSM), Optimization, Modeling, Cooperative Game Theory, Conflict Resolution, Decision Support System (DSS), FERC, Licensing, California.

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" وداع مادرانه "

در دیار غربت و تنهایی ام
برتصاویر جوانی بنگرم

ترک خاک میهن و بغض عزیزان در وطن
اضطراب و درد وجدان وفغان خویشتن

لحظه های تلخ و غمگین وداع
ضجهٔ خاموش بابا در فضا

وانگهی یادآورم آن نکته ها
مادرم آموخت در آن لحظه ها :

" کای پسر غمگین نباشی لحظه ای !
کن جدا از آن دلت هر غصه ای !

من رضایت می دهم برترک تو
چون روی تا درس گیری ، پند تو

روزگاری می رسد با یکدگر
دست دردست تو و دست پدر

من منیژه ، آن رضای نازنین
باتوکاوه ، زادهٔ ایران زمین

پرغرورو افتخاریم، شادمانی می کنیم
با همه نامردمان، ما مهربانی می کنیم

پس تو هم بشتاب سوی قله ها
یادت آور هر چه گفتم ، بعدها

درامان باش ای پسر از چشم بد!
چشم بر راهت نشستم تا ابد ! "

چون گذشتند از سرم آن یادها
اشک هایم راببردند بادها

می روم تا من بسازم روزگار
بربگردم در پناه کردگار

بهر میعاد دوباره ، جشن و مهمانی کنیم
دردها و غصه هامان از جهان خالی کنیم

کاوه

دوشنبه، دهم بهمن ماه یکهزار وسیصدوهشتادوچهار

۱/۳۰ بامداد ، دیویس

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Chapter 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. 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). Hydropower facilities in the U.S. are diverse and 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).

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 (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). These reservoirs which are mostly privately-owned, 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 head downstream (lower elevations).

Much of California has cool, wet winters and warm, dry summers, and a resulting water supply that is poorly distributed in both time and space (Zhu et al. 2005). On average, 75 percent of the annual precipitation occurs between November and March, while urban and agricultural demands are highest during the summer and lowest during the winter. Currently, California's large winter snowpack melts in the spring and early summer, replenishing water supplies during these drier months.

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). Temperature variations due to climate change can affect the amount and timing of runoff. Climate warming is expected to reduce accumulated snowpack by melting it sooner and shift some precipitation from snow to rain. Therefore, a shift in the peak flows from late spring and early summer to late winter and early spring is anticipated. 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.

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 adaptability of California’s high-elevation hydropower system to hydrologic changes and the global warming effects on statewide hydroelectricity generation by high-elevation facilities.

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 climate change. Optimization models are common for studying the performance of hydropower systems under different conditions and for guiding reservoir operations. Conventional simulation and optimization methods used for hydropower systems (Grygier and Stedinger, 1985; Arnold et al, 1994; Jacobs et al., 1995; Vicuna et al., 2008) are quite useful but their application to extensive hydropower systems is intensive and costly. Studying climate change effects on hydropower generation 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. This dissertation introduces a new method and develops a new model for studying optimal operation of high-elevation systems. The developed model is then used for estimating the effects of climate change on the high-elevation hydropower system in California under three different climate warming scenarios (Dry, Warm, and Warming-Only).

The nonfederal dams in the United States which are used for hydroelectric generation are under the regulatory authority of Federal Energy Regulatory Commission (FERC), which issues operation licenses, for terms of 50 years or less to balance hydropower production against environmental awareness and implications of hydropower generation (Kosnik, 2005). Hydropower generation creates significant bioregional impact on the health of aquatic and riparian ecosystems and the periodic relicensing of hydropower facilities regulated by FERC is the only formal opportunity to reduce these impacts through new license conditions and settlement agreements that better reflect the range of modern societal goals. (Kosnik, 2005)

To legally continue operation, the dam owner should file for a new license at the end of the initial license period. The official reliceinsing process is expected to average five years to completion. However, statistics show that 27 percent of the licenses issued by FERC between 1982 and 1988 took longer to issue than the expected 5 years with the longest taking 21 years to complete (Kosnik, 2005). The most variability in the processing time is associated with stage 3 of the relicensing process in which the parties should agree upon and bargain over the available instream water below the reservoir throughout the year.

With more than 150 projects facing re-licensing in California by 2020, FERC relicensing will be complicated, lengthy and resource-intensive. This problem can be exacerbated by expected climate change which may significantly affect various environmental resources and ecosystems, as well as hydropower production and operations across California. Although changes in operation rules may help being adapted to new climatic conditions and minimize revenue losses to some extent, environmental constraints, imposed on operations by FERC as a result of pressure by the interest groups, might limit the flexibility of the system to respond to climate change.

It is important to interest groups and environmental advocates that long-term licenses and agreements can address changes and reduce the likelihood that operations will produce irreversible ecosystem impacts before subsequent license renewals. Thus, they take as much effort as possible in stage 3 to secure their rights. Generally, environmental interest groups are expected to seek to hasten the process (independent of final relicensing outcome) to save endangered riverine resources while the dam owners and hydropower investors are mostly seeking to slow the process to postpone financially constraining environmental mitigation requirements. However, climate change may change this trend as environmental and revenue losses may provide an incentive for cooperation to speed license renewal in the next decades.

Cooperative game theory is applied in this dissertation for understanding the causes of the delay in the stage 3 of FERC relicensing and exploring why fixed terms of a FERC license might disprove the performance of the hydropower system and its environment under climate change. The suggested method can support ongoing bargaining and negotiations of the interested parties and may be used to investigate if climate change provides an incentive for cooperation and speeding the relicensing procedure.

This dissertation includes four chapters.

Summary of Next Chapters

- Chapter 2 presents a novel approach for modeling 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 135 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 and release capacity, penstock head, and efficiency 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. An extensive comparison of the EBHOM with a traditional hydropower optimization model used in California and the reliability of EBHOM's predictions are discussed in this chapter.

- In Chapter 3 EBHOM is applied to facilitate practical climate change and other low-resolution system-wide hydropower studies, based on the historical generation data of 137 high-elevation hydropower plants for which the data were complete for 14 years. Employing recent historic hourly energy prices, the model explores energy generation in California for three climate warming scenarios (dry warming, wet warming, and warming-only) over 14 years, representing a range of hydrologic conditions.

- In Chapter 4 a method based on the Nash and Nash-Harsanyi bargaining solutions is developed to explore the FERC relicensing process, in which the owners of nonfederal dams in the United States have to negotiate over available instream water, with different interest groups (mainly environmentalists) downstream. Linkage of games to expand the feasible solution set and the "strategic loss" concept are discussed. The FERC relicensing bargaining model is developed for studying the third stage of the FERC relicensing process. Based on the suggested solution method, it is discussed how the lack of incentive for cooperation can cause long delays in the relicensing process. Further, the potential effects of climate change on the FERC relicensing process are presented and it is argued how in the future climate change may provide an incentive for cooperation among the parties to hasten the relicensing process. Given uncertainty about the future hydrological and ecological conditions, an "adaptive FERC license" framework is proposed, based on cooperative game theory, to improve the performance and adaptability of the system in response to future changes with no cost to the FERC.

- In the final chapter the major contributions, findings, and limitations of this research are discussed and the related future research areas are suggested.

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Chapter 2: Modeling California's High-Elevation Hydropower Systems in Energy Units

This chapter presents a novel approach for modeling 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 135 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 and release capacity, penstock head, and efficiency 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. An extensive comparison of the EBHOM with a traditional hydropower optimization model used in California produced similar results and indicated good reliability of EBHOM's predictions.

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) with some secondary benefits such as flood control. These reservoirs which are mostly privately-owned, 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 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 a 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 is typical 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 guiding reservoir operations. 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. This chapter introduces 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 historical generation in an average hydrologic year at a particular facility in California. 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 14 year period. The chapter 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.

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 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 used 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:

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

Subject to:

$S_1 = 0$ (initial condition) *(2)*

$S_i \leq Scap$ (storage capacity), $\forall i$ *(3)*

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

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

$G_i \leq Gcap$ (generation capacity constraint), $\forall i$ *(6)*

$G_i\ ,\ S_i\ ,\ R_i \geq 0$ (non-negativity), $\forall i$ *(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.

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 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*$_i$) by 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):

$$StorCapPercent = \sum_i(runPercent_i - genPercent_i) \tag{12}$$

or:

$$StorCapPercent = \sum_j(genPercent_j - runoffPercent_j) \tag{13}$$

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) directly used for hydropower generation.

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

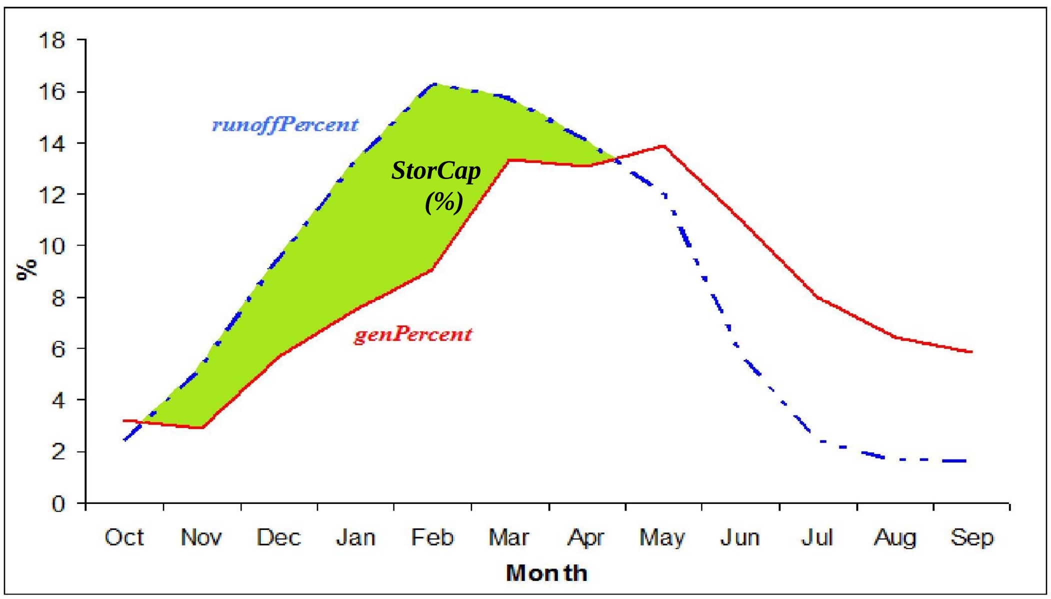


Figure 1. Calculation of operational storage capacity belonging to (above) White Rock hydropower plant based on NSM. The shaded area between the two curves stands for the storage capacity of the reservoir in percentage terms.

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).

Figure 1 shows how the active storage capacity above (belonging to) White Rock hydropower plant, with generation capacity of 165 GWh per month and Average Annual Generation of 537 GWh in California was estimated using NSM. Monthly generation data were available for the years 1985 to 1998. Monthly runoff (inflow) data were 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 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 (22.5 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 121 GWh based on Equation 14.

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 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 more complicated, 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 a limitation of such coarse less-detailed modeling. Incorporating such effects would require much greater modeling effort, which we needed to avoid here.

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 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 (one month is 730 hours in average). 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:

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

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 (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 revenue from each hydropower plant is a function of the proportion of used monthly generation capacity:

$$z_i(h_i) = z_i(g_i) \qquad (17)$$

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

$$g_i = \frac{G_i}{Gcap} \qquad (18)$$

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

$$z_i(g_i) = Gcap.\int_0^{g_i} P_i(g_i)dg_i \qquad (19)$$

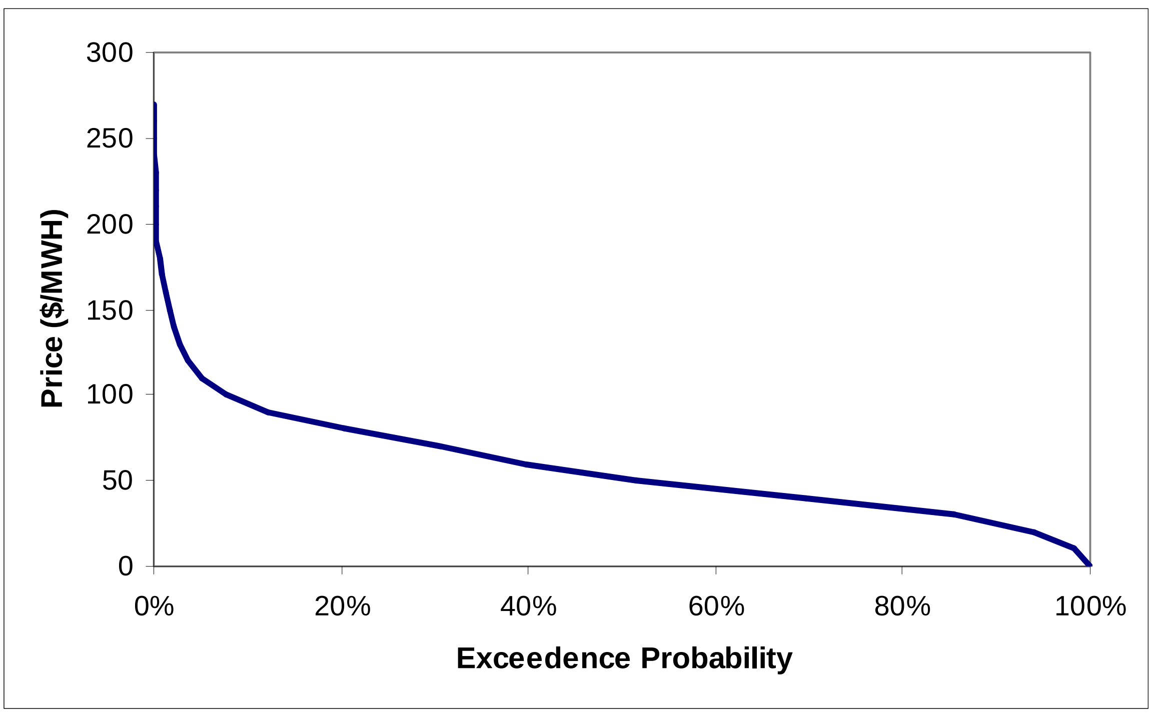


Figure 2. Frequency of California's hourly hydroelectricity price in October 2005 (California ISO OASIS, 2007).

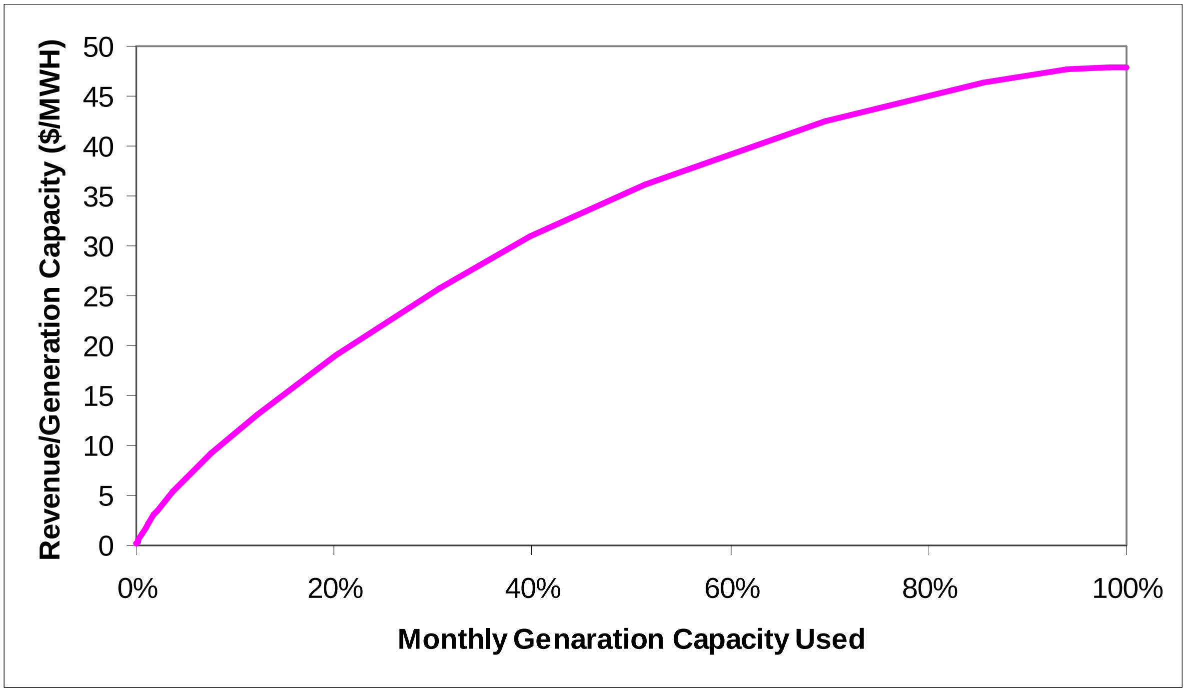


Figure 3. Revenue-generation correlation in October 2005 (California ISO OASIS, 2007). Vertical axis shows the average revenue (in $) per unit of plant generation capacity (in MWh).

Using Equation 19, 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):

$$Maximize\ Z = \sum_{i=1}^{12} z_i(g_i) \qquad (20)$$

This formulation reflects the on-peak on off-peak pricing. These energy market 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.

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:

$$S_1 = big \text{ (initial condition)} \qquad (21)$$

$$S_{min} \leq S_i, \ \forall i \qquad (22)$$

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

$$S_{max} - S_{min} \leq Scap \text{ (storage capacity constraint)} \qquad (24)$$

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 22 and 23), and then constraining the difference (Equation 24), 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.

Comparison for White Rock Power Plant

Figure 4 compares the average historical (recorded) hydropower generation (period 1985-1998) and the EBHOM's estimation of average optimal monthly hydropower generation in the same period at White Rock 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, the 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.

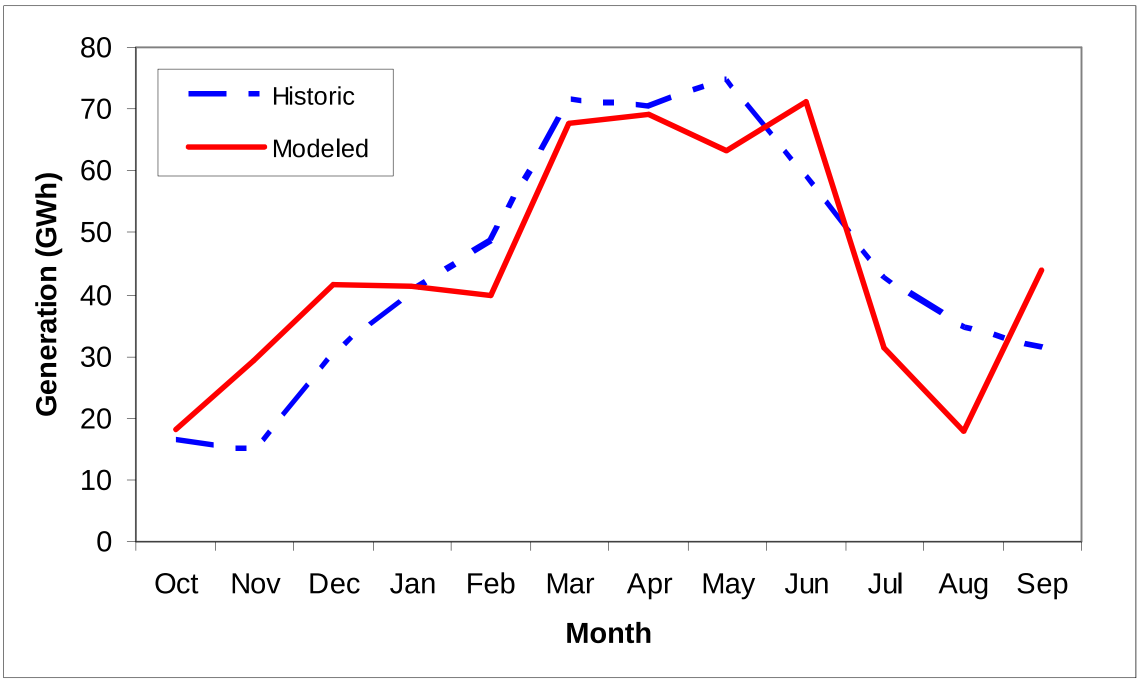


Figure 4. Comparison of average historical monthly electricity generation and optimal monthly electricity generation (found by EBHOM) at White Rock Hydropower Plant in California

Generally, the difference of historical 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 1985 to 1998. 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.

Reliability

To examine the reliability, advantages, and limitations of the proposed method, EBHOM had to be tested against an existing hydropower optimization model on California. Therefore, in a collaborative-comparative study, Madani et al. (2008) studied the climate change effects on hydropower generation of Sacramento Municipal Utility District's (SMUD) hydropower facilities in California through two different approaches. The studied high-elevation hydropower system, known as the Upper American River Project (UARP), is in El Dorado and Sacramento counties within the Rubicon River, Silver Creek, and the South Fork American River drainages, on the west slope of the Sierra Nevada Mountains in California. The UARP has 11 reservoirs which can hold over 524 million cubic meters (425 thousand acre-feet) of water, 8 powerhouses which can generate up to 688 MW of power, and about 45 kilometers (28 miles) of power tunnels/penstocks (Madani et al., 2008).

In the first approach, the energy storage capacities, corresponding to each hydropower facility, were estimated through the NSM. Then EBHOM was developed for the each hydropower facility. In the second approach, a traditional hydropower optimization model (Vicuna et al., 2008) was developed for the whole system. This physically-based model used the conventional volumetric units and restricted the operations to physical constraints (i.e. turbine and reservoir capacity) and operational constraints (e.g. minimum instream requirements). This model assumed no head-storage effect (storage does not significantly affect hydropower head in high head units) which made the model formulation linear when off-peak and on-peak pricing were not considered. To incorporate the on-peak and off-peak pricing, the formulation of the model was modified based on the introduced energy price representation method (Equations 17-20) which made the model non-linear (similar to EBHOM). While EBHOM had a perfect foresight into future hydrologic conditions and used a monthly time step, the second model used a moving horizon approach (Hooper et al., 1991) with variable time steps (daily to monthly) which gave the model a partial foresight at different temporal resolutions into future inflow conditions (for more information regarding the model formulation see Vicuna et al. (2008)).

The two models where solved through piecewise linearization to estimate the monthly hydropower generation revenues between October 1984 and September 1998 under four climate change scenarios as well as the historic scenario. The climate change scenarios used were the outputs from the variable infiltration capacity (VIC) model, a macroscale, distributed, physically based hydrologic model (Liang et al., 1994). The climate scenarios considered in the analysis corresponded to the projections of the NCAR PCM and GFDL CM2 climate models run under the greenhouse gas emission scenarios SRES A2 and SRES B1 (Cayan et al., 2006). Generally, a decline in spring and summer streamflows and an increase in streamflows in winter would be expected under these climate warming scenarios. In terms of extreme daily conditions, higher flood events during winter time and lower flood events in spring and early summer months were projected. Table 1 shows the results of the two models for different climate scenarios. Although the two methods predicted different values for generation and revenue under different climate scenarios, they predicted the same change in generation and revenue under different climate change scenarios with respect to the historic case. The annual generation predicted by EBHOM exactly equaled the historical annual generation, as EBHOM had used the historical annual generation as an annual energy inflow to the system. The conventional method overestimated the annual generation and revenues, however, its predicted generation reduction under climate warming scenarios matched the results of EBHOM.

Table 1. Summary of results of the two methods (EBHOM and the traditional hydropower optimization of Vicuna et al. (2008)) used to study the SMUD system (Madani et al., 2008).

Result	**Method**	***Scenario*** *Historic*	*GFDLA2*	*GFDLB1*	*PCMA2*	*PCMB1*
Annual runoff change with respect to the Historic Case	N/A	N/A	- 52 %	- 37 %	- 12 %	- 3 %
Annual Generation (GWh)	EBHOM	1,672	793	1,055	1,428	1,605
	Traditional	2,647	1,217	1,655	2,246	2,546
Annual generation change with respect to the Historic Case	EBHOM	N/A	- 53 %	- 37 %	- 15 %	- 4 %
	Traditional	N/A	- 54 %	- 37 %	- 15 %	- 4 %
Annual Revenue (Million $)	EBHOM	118	71	87	105	115
	Traditional	167	98	122	150	163
Annual revenue change with respect to the Historic Case	EBHOM	N/A	- 40 %	- 26%	- 11 %	- 3 %
	Traditional	N/A	- 41 %	- 27%	- 10 %	- 2 %

Figure 5 shows the recorded average monthly generation and the predicted average monthly generation from both methods for historical inflows. One reason for the mismatch between the modeled and recorded generations is the use of hydropower prices in 2005 for the whole modeling period (1985-1998) due the unavailability of earlier price data.

Although there was a difference between the actual and simulated generations, both models suggested a comparable monthly generation pattern, similar to the average monthly hydropower price pattern in 2005. Both models overestimated generation in the September-January period and underestimated generation in other months.

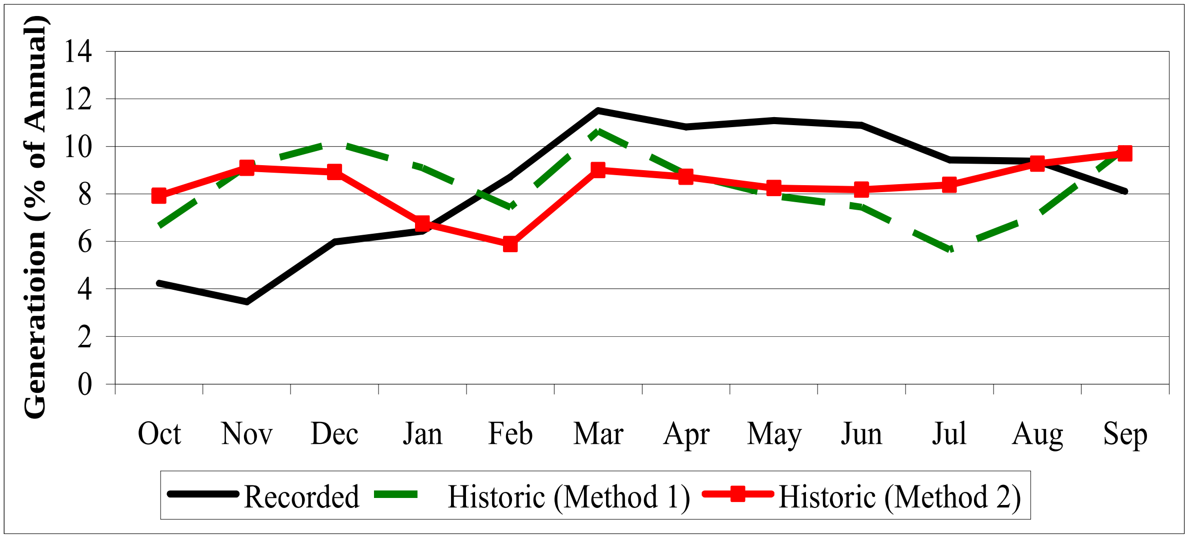
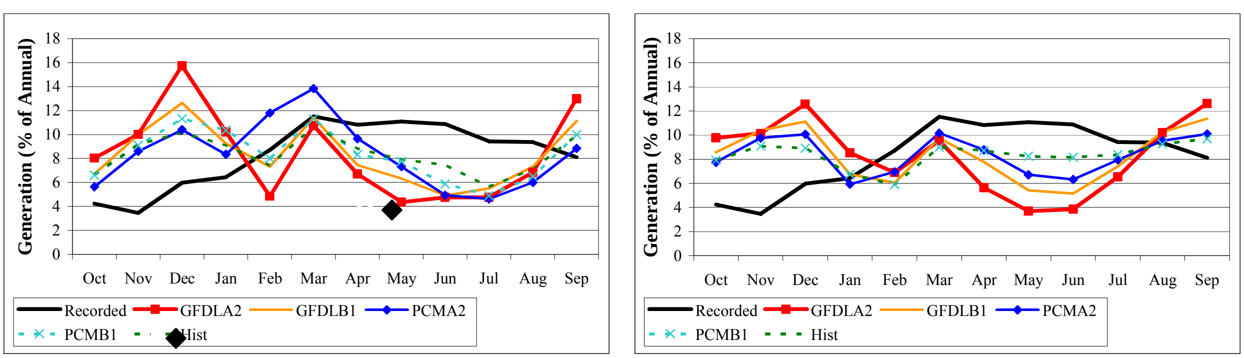


Figure 5. Recorded and modeled monthly hydropower generation of the SMUD system (Methods 1 and 2 correspond to EBHOM and the traditional hydropower optimization model of Vicuna et al. (2008), respectively) (Madani et al., 2008)

Figures 6a and 6b show the predicted average monthly hydropower generation distribution (Equation 9) through both methods under different climate change scenarios as well as the recorded average monthly hydropower generation distribution during the study period. Both models predicted similar monthly generation patterns under different climate scenarios.

Figures 7a and b show the estimated end of month used storage capacity from both methods for different climate scenarios. These figures indicate what percentage of storage capacity (energy storage capacity in Figure 7a and volumetric storage capacity in Figure 7b) used at the end of each month. Although the units are different, both methods predicted the same pattern of changes under different climate scenarios. Although, spills are expected with climate change, Figures 7a and b may imply that the storage never reaches the maximum capacity and there is no spill. However, what is shown here is the maximum capacity of the whole system. Thus, while one reservoir spills, other reservoirs might not be full. Based on the results, not all reservoirs fill at the same time. Thus, the used storage capacity never reaches a hundred percent of the systemwide storage capacity. A comparison between Figures 7a and b implies that in general, more systemwide is used with EBHOM. This is due to two reasons. First, the NSM underestimates the storage capacity of the system. Second, the NSM considers energy storage capacity as that portion of the total capacity which has been actually used for energy generation. Thus, it ignores that portion of the actual capacity which might be used for other purposes. NSM also does not allow carryover storage; thus active energy storage reaches zero during the year (Figure 7a). However, the traditional model allows for carryover storage, and with a foresight of future inflow conditions might use carryover storage to supply generation under critically dry hydrologic conditions in future years. Therefore, based on the second method, average used storage capacity never reaches zero.

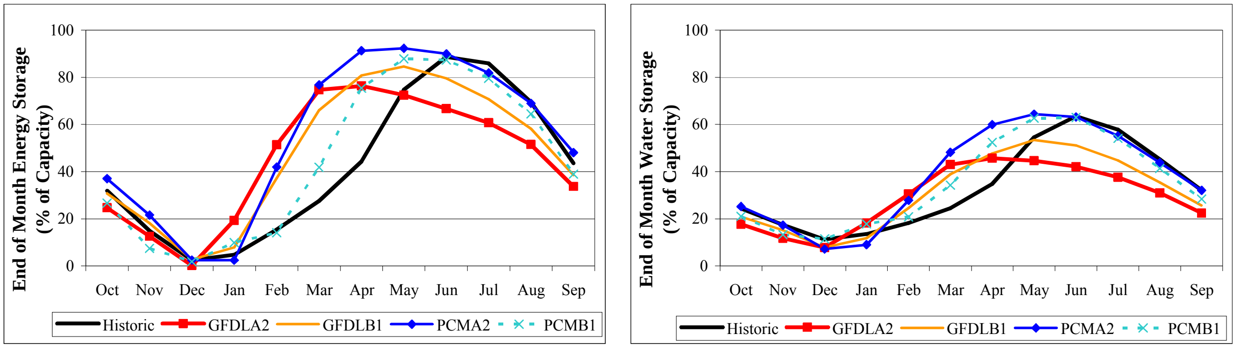
Since NSM underestimates storage capacities, the first method underestimated the adaptability of the studied system to climate change. EBHOM optimizes monthly hydropower generation based on its perfect foresight into future hydrological pattern. This kind of management is impossible in practice as there is always some risk associated with reservoir operations decisions because of inability to forecast the future hydrologic conditions perfectly. Despite these drawbacks, EBHOM's results were very similar to those of a traditional optimization model used for modeling hydropower operations in California. Both methods predicted almost the same changes in annual generation and revenues under climate warming scenarios and predicted the same trend of monthly generation and monthly water (energy) storage. EBHOM's simplicity and the amount of detailed information required for modeling a given hydropower system are the advantages of this method over traditional volumetric based models. Since modeling large high-elevation hydropower systems like that in California with more than 150 hydropower plants through traditional methods would be tedious and costly, EBHOM can be used in preliminary studies of the high-elevation hydropower systems in California. On the other hand, a detailed traditional optimization model can provide information on some key variables for understanding future system operations including water storage in the reservoirs, spills in different months of the year, and minimum downstream flows. Therefore, EBHOM is useful for studying large hydropower systems when there is less interest in details of the system and the traditional method is preferable when more detail is needed for particular systems.



a- EBHOM's results

b- Traditional hydropower optimization model's results

Figure 6. Hydropower generation of SMUD system under different climate scenarios (Madani et al., 2008).



a- EBHOM's results

b- Traditional hydropower optimization model's results

Figure 7. End of month used storage in the SMUD system (Madani et al., 2008).

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 1985 to 1998 was used to estimate the average monthly hydropower energy generation 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 from 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 historical 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 1985-1998. 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 8 shows the range of the estimated energy storage and generation capacities of the studied high-elevation hydropower plants. The annual energy storage capacities of almost half of the studied power plants are at least 1.5 times larger than their monthly generation capacity, which provides some flexibility in operations. For more than 100 studied power plants, energy storage capacity exceeds one month of generation capacity.

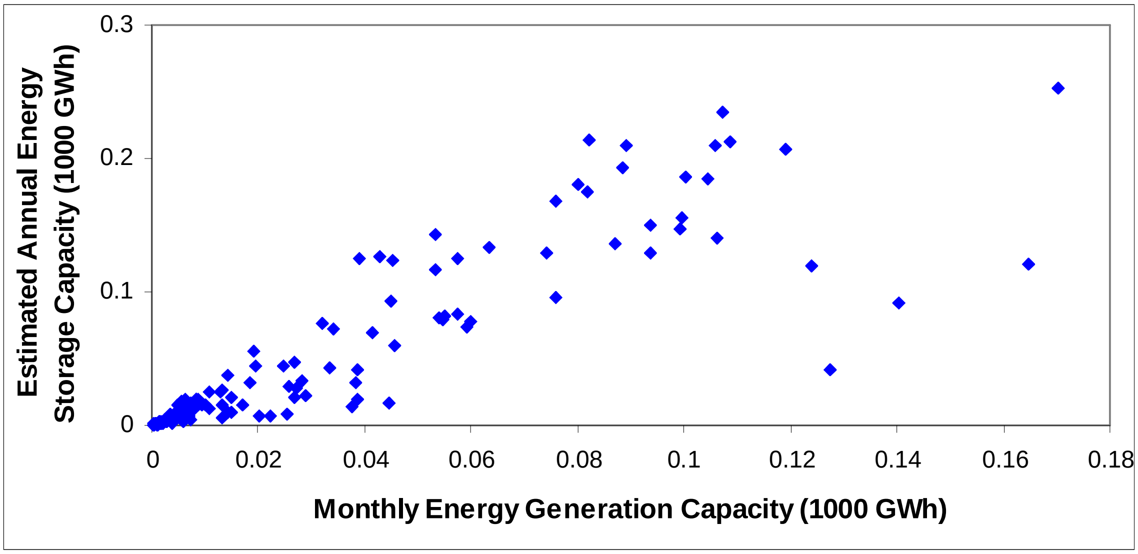


Figure 8. Range of the estimated energy storage and generation capacities of the 137 studied high-elevation hydropower plants in California

Figure 9 shows the historical and modeled average energy generation of 137 hydropower plants for the period 1985 to 1998. (The analysis has not been done for an average year but for 14 years of hydrologic (energy inflow) annual variability, spanning dry, wet, and average years. The results are reported as averages over the 14 year period for which 14 model runs were required). The optimized generation for the historical climate differs from historical observations (the dashed curve in Figure 9). 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. Generation results are price driven and follow the California ISO energy price trends in 2005.

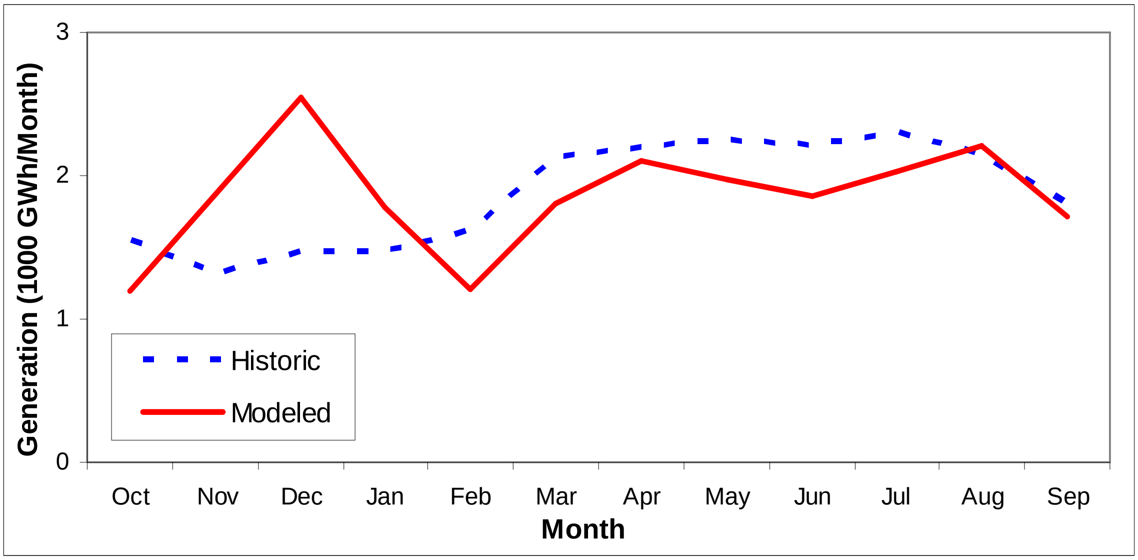


Figure 9. Comparison of historical average monthly electricity generation and optimal average monthly electricity generation (found by EBHOM) of 137 hydropower units in California in the 1985-1998 period.

Figure 10 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 December 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. Thus, under historical conditions, refill starts in January and drawdown starts in July.

Figure 11 indicates the average shadow prices of annual energy storage and generation capacities (the average increase in annual revenue per unit of annual capacity expansion) for all 137 reservoirs for the study period. This figure shows the average increase in annual revenue (y-axis) per MWh annual energy storage/generation capacity expansion for corresponding number of power plants (x-axis). For instance, increase in annual revenue is less than \$10 annual revenue per MWh energy storage capacity expansion for 18 of the studied power plants. For most of the studied power plants, one unit of annual storage capacity expansion is more beneficial than one unit of annual generation capacity expansion as water can be stored in the reservoir in low-value months to be released in summer when energy prices are higher. Although expansion of storage and generation capacities is always beneficial, 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.

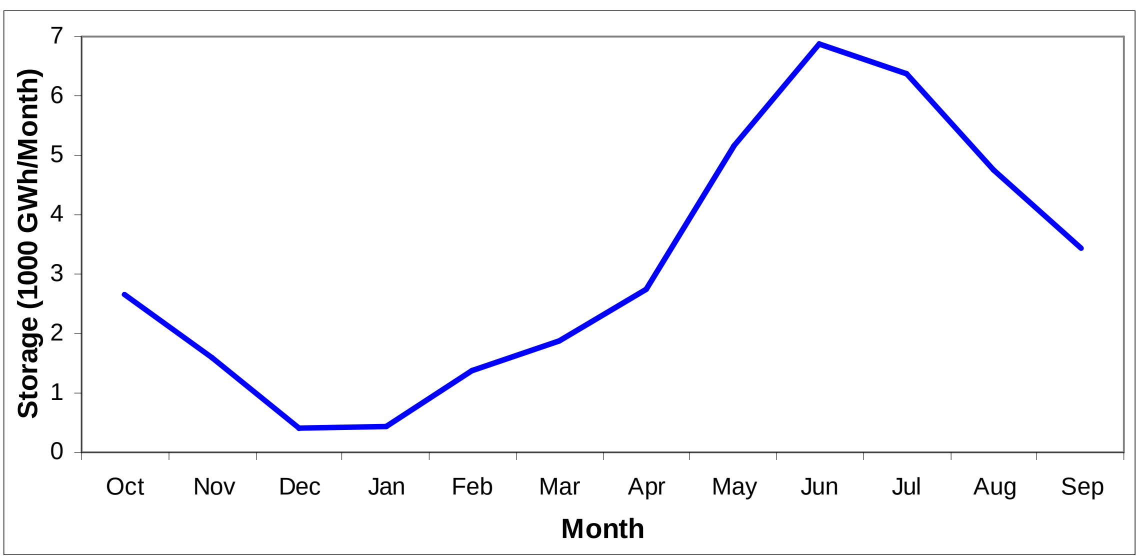


Figure 10. Average modeled total end-of-month energy storage (found by EBHOM) of 137 hydropower units in California in the 1985-1998 period.

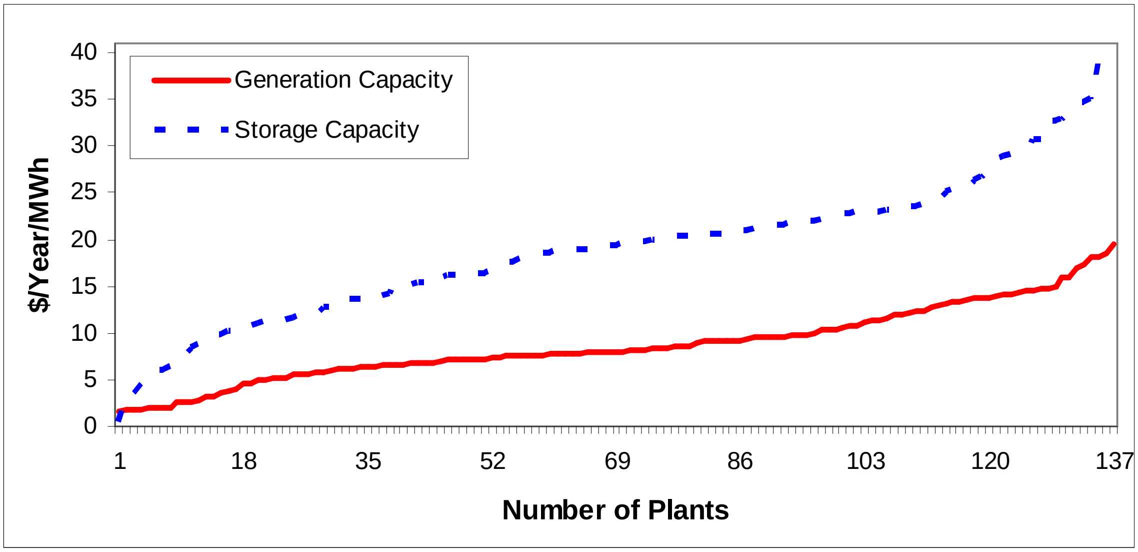


Figure 11. Average shadow prices of monthly energy generation and energy storage capacities (found by EBHOM) of 137 hydropower units for California in the 1985-1998 period

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 for 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 use and prices (for heating) and increase use and prices in summer (for cooling). Energy prices also might change from changes in supply. For instance, more energy generation from earlier snowmelt might reduce energy prices in early spring. 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 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.

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 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 improve 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.

Conclusions

This study introduced an innovative simplified 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 based on seasonal shifts of energy inflows to generation, energy inflows are based on seasonal inflow distributions, and generation capacity 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 computation. This approach is used to represent 137 high-elevation (high-head) units in California. Although the developed method required some simplifying assumptions, EBHOM was found reliable when tested against an existing hydropower optimization model in a collaborative-comparative study of climate change effects on hydropower generation of Sacramento Municipal Utility District's (SMUD) hydropower facilities in California. 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. EBHOM's simplicity and the amount of detailed information it requires for modeling a given hydropower system are the advantages of this method over traditional volumetric based models which make EBHOM a useful method for studying large hydropower systems when there is less interest in details of the system.

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 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.

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Chapter 3: Estimated Impacts of Climate Warming on California's High-Elevation Hydropower

California's hydropower system is composed high and low elevation power plants. There are more than 150 high-elevation power plants, at elevations above 1,000 feet (300 meters). Most have modest reservoir storage capacities, but supply roughly 74 percent of California's in-state hydropower. The expected shift of runoff peak from spring to winter due to climate warming, resulting in snowpack reduction and increased snowmelt, might have important effects on power generation and revenues in California. The large storage capacities at low-elevation power plants provide flexibility to operations of these units under climate warming. However, with climate warming, the adaptability of the high-elevation hydropower system is in question as this system was designed to take advantage of snowpack, a natural reservoir. With so many high-elevation 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) was developed to facilitate practical climate change and other low-resolution system-wide hydropower studies, based on the historical generation data of 137 high-elevation hydropower plants for which the data were complete for 14 years. Employing recent historical 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 14 years, representing a range of hydrologic conditions. The system is sensitive to the quantity and timing of inflows. While dry warming and warming-only climate changes reduce average hydropower revenues, wet warming could increase revenue. Re-operation of 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, although such expansions might not be cost-effective.

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 that 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, agricultural, and electricity demands are highest during summer and lowest during winter. Spatially, more than 70 percent of California’s 88 billion cubic meters (bcm) average annual runoff occurs in the northern part of the state (CDWR 1998). 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, and other purposes.

California relies on hydropower for 9 to 30 percent of 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. Temperature changes due to climate change can affect the amount and timing of runoff. Climate warming is expected to reduce accumulated snowpack by melting it sooner and shift some precipitation from snow to rain. Therefore, a shift in the peak flows from late spring and early summer to late winter and early spring is anticipated. Such a shift might hamper California's ability to store water and generate electricity for the spring and summer if available storage capacity is insufficient. 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 in the reservoir is limited by the available 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.

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), or a few individual hydropower systems (Vicuna et al. 2008 and 2009). There is still a lack of knowledge about the adaptability of California's high-elevation hydropower system to hydrologic changes and global warming effects on statewide hydroelectricity generation by largely single-purpose high-elevation hydropower facilities.

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 in multipurpose reservoirs, while most in-state hydroelectric 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, but it also produces 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 at higher-elevations (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 a change in runoff volume and timing, as a result of more precipitation in form of rain instead of snow, reduced snowpack, and increased snowmelt in late winter and early spring. 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 (in press) for California's high-elevation hydropower system.

Method

One hundred thirty-seven high-elevation hydropower plants (defined as units located above 1,000 feet(300 meters)) in California were identified in this study for which historical monthly generation data were complete for the 14 year 1985 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, in press), which is based on energy flows and storage instead of water volume balances. EBHOM is a monthly-based optimization model that 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 with details having lesser importance. Madani el al. (2008) found EBHOM reliable for climate change studies by comparing EBHOM against a traditional hydropower optimization model of the Sacramento Municipal Utility District (SMUD) reservoir system (Vicuna et al., 2008). Both models produced similar results when operations of SMUD were modeled under four climate scenarios.

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 Maury Roos, the former California Department of Water Resources (DWR) chief hydrologist. Monthly runoff distributions were found for each elevation range (Figure 12). This figure shows the value of snowpack to the system. Runoff peaks later at higher elevations where snowpack is larger and lasts longer. Average historical monthly generation data were perturbed using monthly runoff perturbation ratios of three climate change scenarios, a Dry Warm Scenario (GFDL A2-39), a Wet Warm Scenario (PCM A2-39) (described by Vicuña et al., 2005), and a Warming-Only Scenario. A perturbation ratio is the ratio of flow volume or energy (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 (historical) 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 13 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.

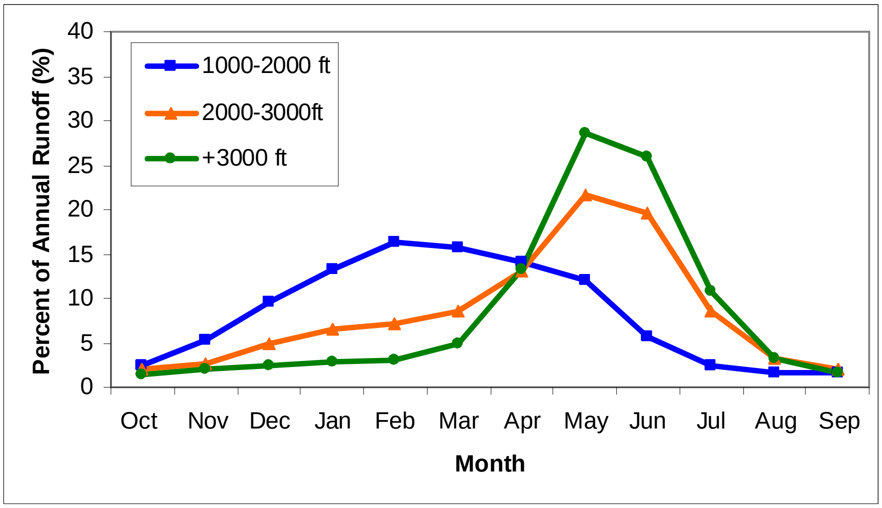
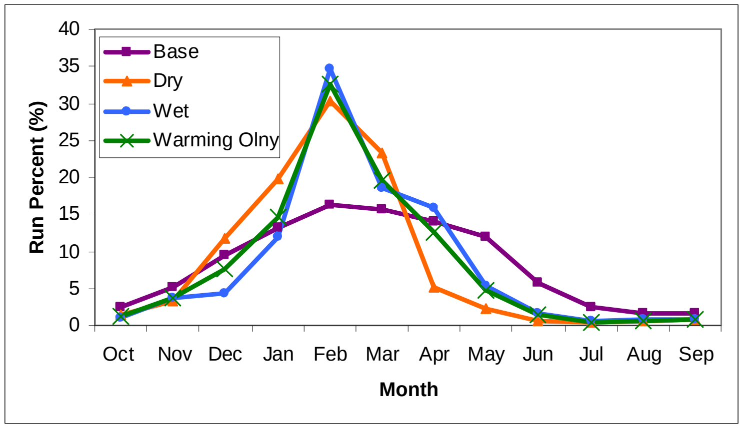


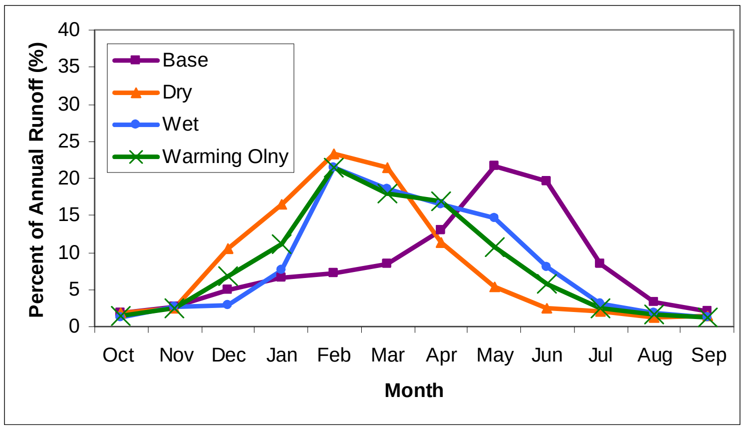
Figure 12. Monthly runoff distributions at different elevation ranges.

The available energy storage capacity at each power plant was estimated based on the No Spill Method (NSM) as explained in Madani and Lund (in press) and tested in Madani et al. (2008). EBHOM was designed for net revenue maximization. In California, most hydropower plants are operated predominantly 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 or non-linear. The non-linear EBHOM is solved by linear programming through piecewise linearization of the concave revenue function (Madani and Lund, in press). Linear EBHOM does not capture the effects of off-peak and on-peak energy prices on operations well. The non-linear EBHOM was used here with off-peak and on-peak energy prices captured using a method that considers the non-linear relationship between monthly generation and monthly revenue based on recorded hourly prices (Madani and Lund, in press). Real time hourly hydroelectricity prices for 2005-2008 (California ISO OASIS, 2009) were used in this study, as such data were only available for this period at the time of this study. Real time hourly data are useful for incorporating on-peak and off-peak hydropower prices. Therefore, using the real time data set which does not match the modeling period was preferred to application of average monthly prices which result in failure to capture the effects of on-peak and off-peak pricing.

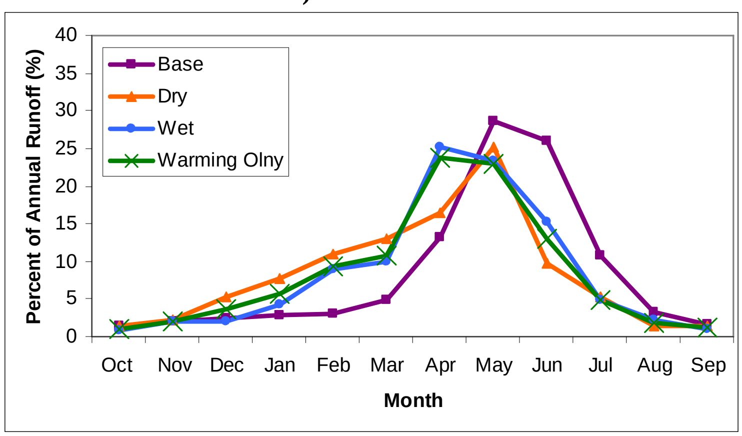
EBHOM is a deterministic optimization model. Therefore instead of using rule curves for reservoir operations, as done in simulation models, EBHOM finds operations which yield the highest possible revenue for the known inflows in a given year, subject to energy storage and capacity constraints which are constant over the modeling period. EBHOM uses a unique method for reflecting the non-linear relationship between the average monthly hydropower price and the hours of turbine usage in that month, based on the historical real-time hourly price set incorporated in the model (here, the 2005-2008 prices were used). The average hydropower price in each month is determined based on the proportion of generation capacity used in that month while marginal benefit of used generation capacity decreases with increase in the used proportion of turbine capacity. Therefore, prices can vary from month to month and also between the same months in different years, based on the proportion of generation capacity used. (Madani and Lund, in press)



a) 1000-2000 ft



b) 2000-3000 ft



c) + 3000 ft

Figure 13. Monthly runoff distributions for different climate change scenarios and elevation ranges.

For each year from 1985 to 1988, EBHOM was run to estimate optimal monthly reservoir storage and energy generation decisions for each of the 137 power plants. The model was run for four climate scenarios, including the base case (Historical) hydrology and three climate change hydrologies (Dry Warming, Wet Warming, and Warming-Only). Since the model optimizes decisions one year at a time, 14 years of results were used to model variations in performance over the 1985 to 1998 period. Assuming no over-year storage, release decisions in each year are independent. Figure 14 (from Madani and Lund (in press)) indicates the range of estimated energy storage and generation capacities of the 137 studied high-elevation hydropower plants. The annual energy storage capacities of most of the studied high-elevation hydropower plants are at least 1.5 times larger than their monthly generation capacity, providing some operational flexibility. For more than 100 of these power plants, active storage capacity exceeds one month of generation capacity (Madani and Lund, in press).

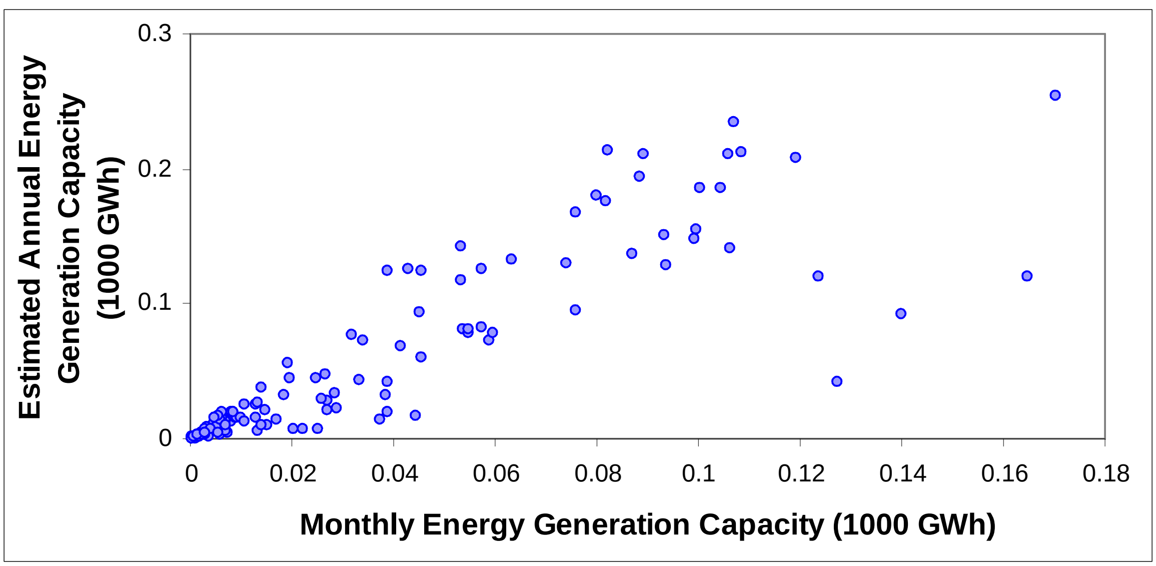


Figure 14. Range of the estimated energy storage and generation capacities of the 137 studied high-elevation hydropower plants in California (adopted from Madani and Lund (in press)).

Results

Table 2 indicates how energy generation, energy spill and annual revenue change with climate scenarios. Revenue is greatest for the Wet-warm scenario and least for the Dry-warm 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 pattern. Although generation is almost 6 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.

Table 2. EBHOM's results (average of results over 1985-1988 period) for different climate scenarios

	Base	***Dry***	***Wet***	***Warming-Only***
Generation (1000 GWH/yr)	22.3	17.9	23.6	22.0
Generation Change with Respect to the Base Case (%)		- 19.7	+ 5.8	- 1.3
Spill (MWH/yr)	130	96	1,112	735
Spill Change with Respect to the Base Case (%)		- 26	+ 755	+ 255
Revenue (Million $/yr)	1,791	1,536	1,822	1,754
Revenue Change with Respect to the Base Case (%)		- 14.2	+ 1.7	- 2.1

While total annual inflow does not change for the Warming-Only scenario (shifting only runoff timing), total revenue is reduced by 2 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, affect generation patterns, total generation, and power values. When reservoir 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 more than 14 percent even though energy generation reduction under this scenario exceeds 19 percent. Energy spills under this scenario increase relative to the Base case during peak runoff months, causing some off-peak generation losses.

Generation Changes with Climate Warming

Figure 15 shows average monthly energy generation for 1985 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 keep the reservoir storage higher for generation in later months with higher energy prices. Summer generation is less than the Base case for all three climate warming scenarios. Generation under the climate warming scenarios can be higher than the Base case during the January-April period due to increased runoff peaks and limited capacity to store this shift in peak runoff. In the rest of the year, generation under climate change is always less than the base generation, but with almost the same trend which mostly follows the energy price pattern. 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).

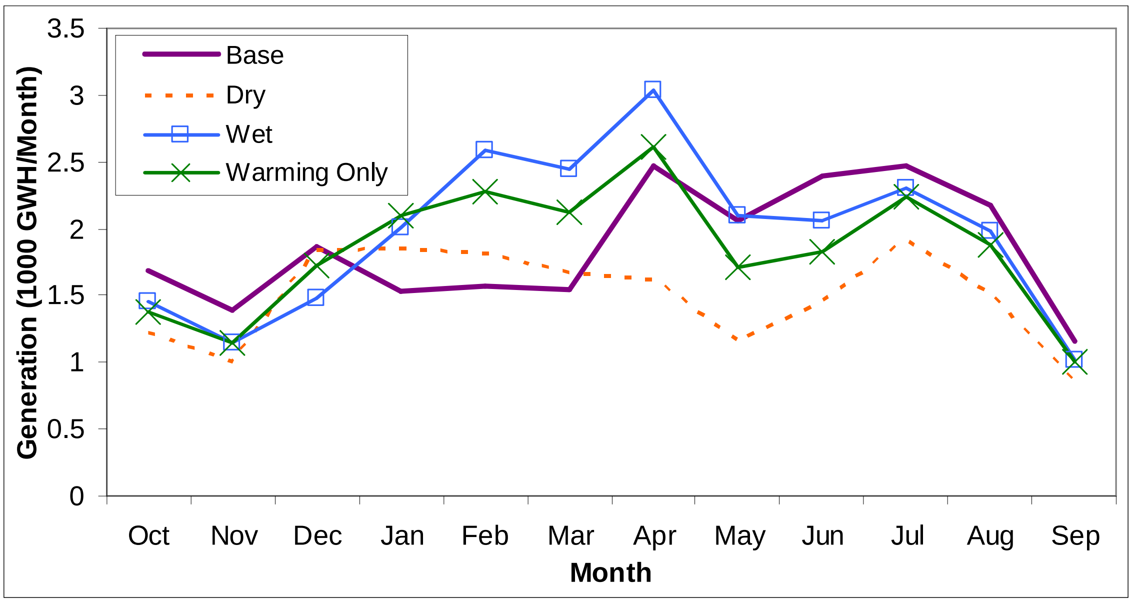


Figure 15. Average monthly generation (1985-1998) under different climate scenarios.

Figure 16 shows the frequency of optimized monthly generation for each month over the 14 year period (1985-1998) summed for all units, for the different climates. Dry climate warming always has considerably less generation than Base generation over the 14 year period. Under the Wet climate generation exceeds the base case 85 percent of the time. However, in 65 percent of months, the difference is small. Generation with the Warming-Only scenario is less than the base case in 60 percent of months. It differs only slightly from the base generation in 65 percent of months. Generation is considerably less than the base generation in 25 percent of months (summer months), and higher in 10 percent of months (late winter-early spring months). 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 when storage capacity cannot store more 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.

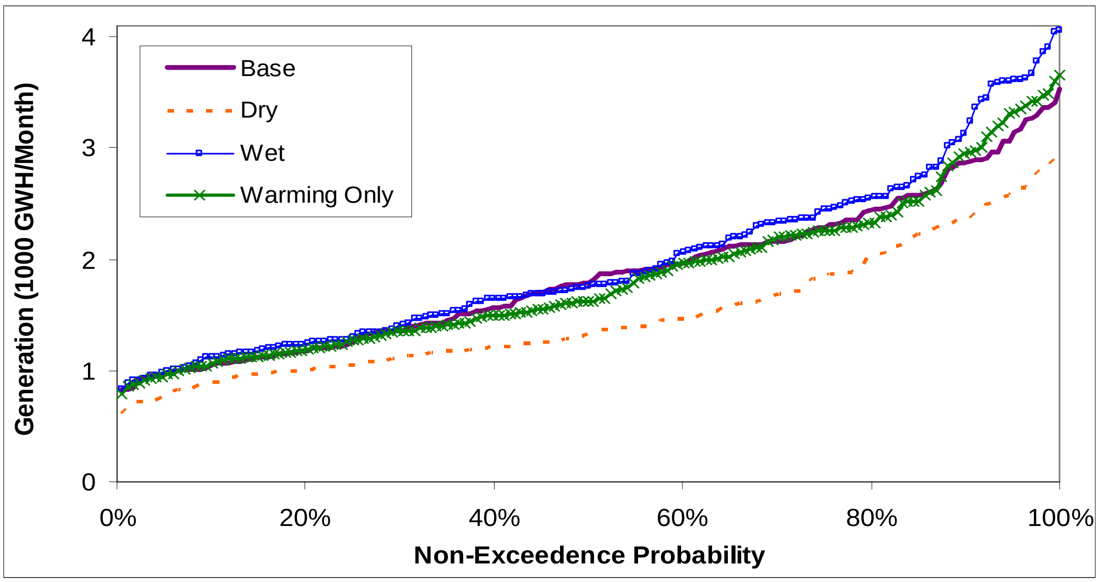


Figure 16. Frequency of optimized monthly generation (1985-1998) under various climate scenarios (all months, all years, all units).

Reservoir Storage Changes with Climate Warming

Figure 17 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 by the end of December to prepare to capture expected inflow from winter precipitation and later spring snowmelt. On average, reservoirs fill by June and gradually empty 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 the start of the refill season, energy storage peaks earlier and drawdown begins a month earlier due to earlier snowmelt. Climate change generally increases average reservoir storage (stored energy) between February and May due to snowpack loss.

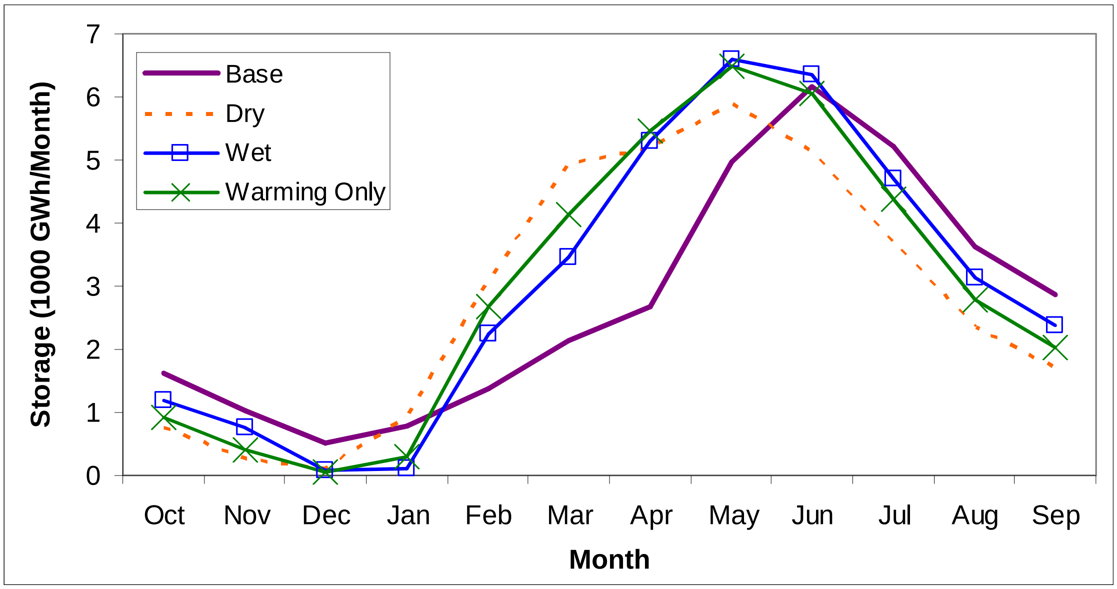


Figure 17. Average total end-of-month energy storage (1985-1998) under different climate scenarios.

Energy Spills with Climate Warming

Figure 18 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 35 and 30 percent of months under the Wet and Warming-Only scenario, respectively. Energy spill does not occur more than 20 percent of the time, under the Base and Dry scenarios. The magnitude of spills also increases for Wet and Warming-Only scenarios. With the Dry scenario, the magnitude of spill decreases in 14 percent of the months. 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.

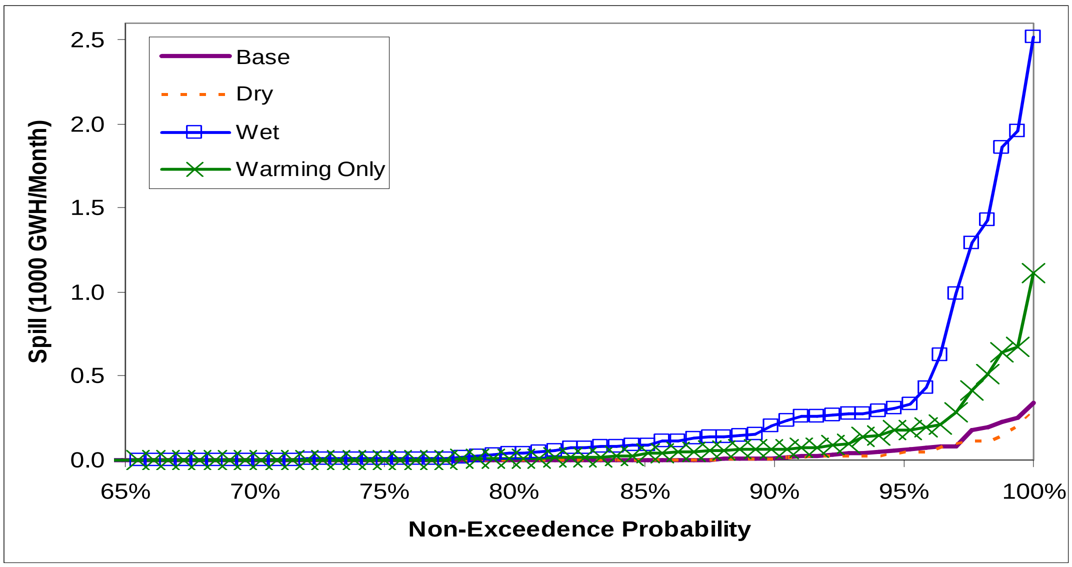


Figure 18. Frequency of total monthly energy spill (1985-1998) under different climate scenarios (all months, all years, all units).

What is calculated as energy spill in this study is the increased historical energy spill, because annual historical generation (actual recorded output of the system) in each year during 1985 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 historical scenario is only 0.6 percent of total generation in average.

Figure 19 shows the distribution of total average monthly energy spill for different climates. Under the historical climate, energy spills occur from January to May when inflow to the system peaks. Monthly energy spill peaks in May under this scenario and can be as high as 100 GWh on average. Climate warming generally increases spills above the base case in months with low hydropower prices. Energy spills are expected from January to May under climate warming. Most energy spills occur in January with the Dry climate and in February with the Wet and Warming-Only climates. The average monthly energy spill can be as high as 60 GW for the Dry scenario and 800 and 300 GWh under the Wet and Warming-Only scenarios, respectively. The changes in the magnitude and timing of spills under different climate warming scenarios indicate the relative importance of runoff inflow timing and magnitude to the performance of this system.

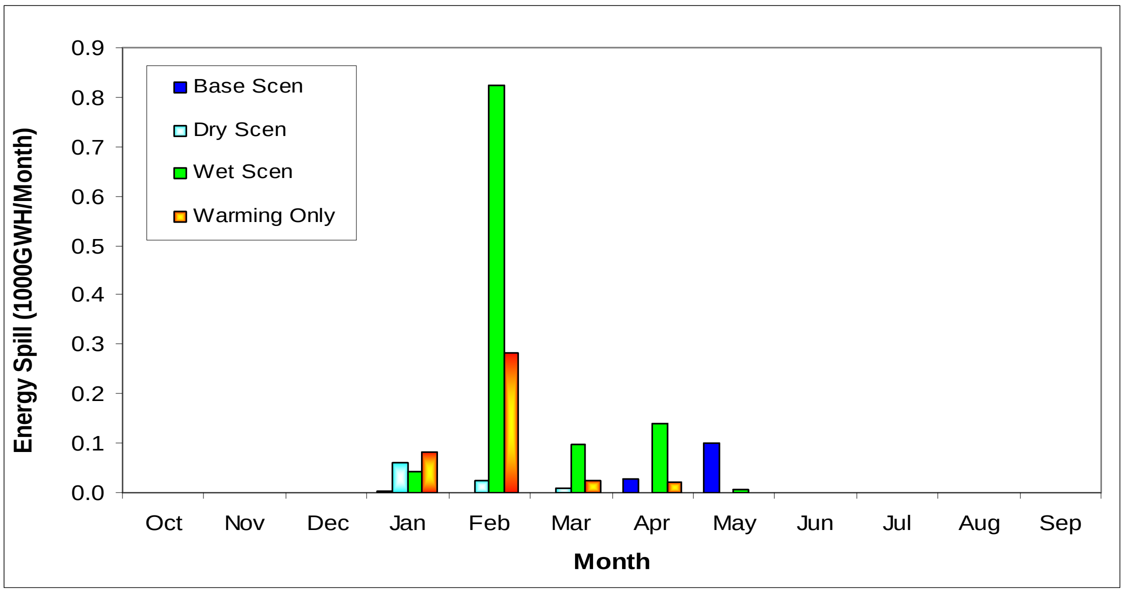


Figure 19. Average monthly total energy spill (1985-1998) under different climate scenarios.

Figure 20 plots the frequency curve of total annual spill from the system for the study period. Energy spill under the Base scenario is not substantial for 60 percent of the years. Annual energy spill frequency and magnitude both increase with Wet and Warming-Only scenarios and decrease with Dry warming. Most energy spill occurs with the Wet scenario, in more than 80 percent of years. Under the Warming-Only and Dry scenarios, energy spills are significant in more than 60 and 30 percent of years, respectively.

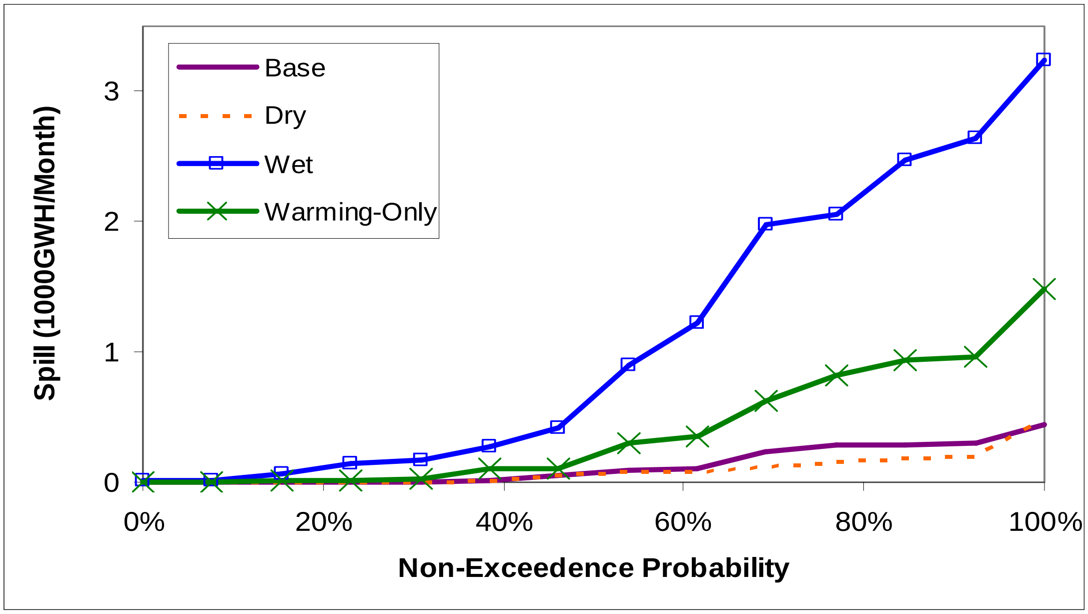


Figure 20. Frequency of total annual energy spill (1985-1998) under different climate scenarios (all years, all units).

Revenue and Energy Price Patterns under Climate Warming

Figure 21 indicates climate warming effects on monthly average price received for generated energy. Climate warming generally increases average hydropower prices at least in more than 70 percent of months, as generation with climate warming is less than base generation in most of the year, especially in high-value months. Energy prices under the wet scenario are the same as the base case prices in almost half of months. As expected, the rise in prices received 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 95 percent of the time. Average received energy price frequency curves for Wet and Warming-Only scenarios show similar behavior, with higher prices under the Warming-Only scenario, highlighting the importance of runoff timing over quantity for optimal system operations.

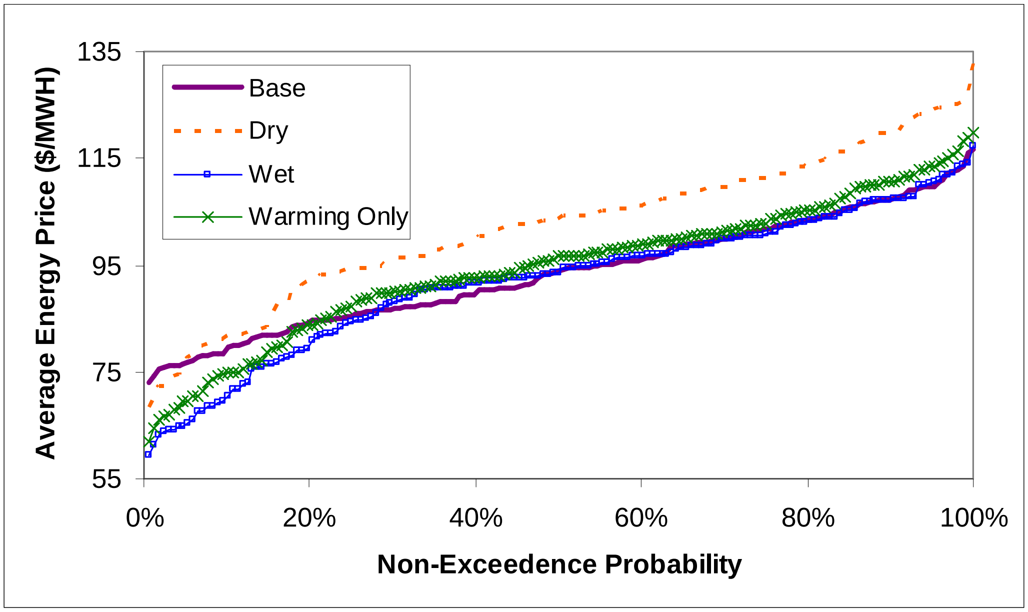


Figure 21. Frequency of monthly energy price (1985-1998) under different climate warming scenarios (all months, all years, all units).

Figure 22 shows the effects of climate warming on the frequency of total annual revenues from all 137 hydropower plants studied for the period 1985 to 1998. Although monthly average prices received for generated energy were higher under the Dry scenario, the increase in average prices received does not compensate for the Dry scenario reduction in energy generation. On average, annual revenues are $250 million lower than the base case for the Dry scenario. Annual revenue under the Wet scenario exceeds Base scenario revenue in 70 percent of years due to increased annual generation. However, the maximum annual revenue is obtained under the Base scenario, highlighting the importance of timing of inflows rather than just their quantity. For the same reason (changed timing of inflows), annual revenue for the Warming-Only scenario is always less than the Base case. Nevertheless, the difference is insignificant in 40 percent of years.

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, in press).

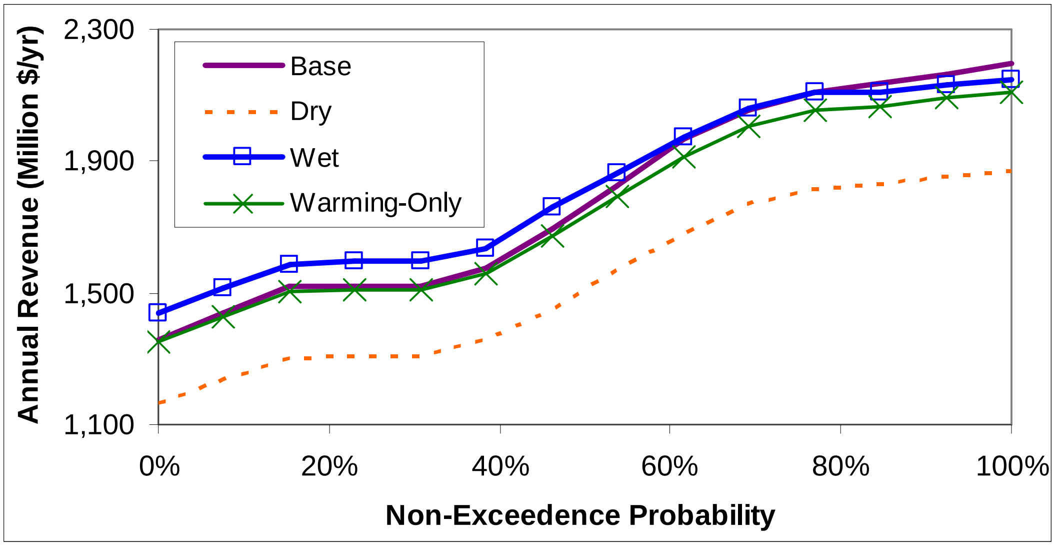


Figure 22. Frequency of total annual revenue (1985-1998) under different climate scenarios (all years, all units).

Benefits of expanding energy storage and generation capacity

Figure 23 shows, on average, how energy storage capacity expansion changes hydropower generation revenues for different climate scenarios over the study period (14 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 \$35, \$47, \$54, and \$55 for all the studied power plants (137 units) under the Base, Dry, Wet, and Warming-Only scenarios. 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 (except for 8 power plants under the Dry scenario), altough such expansion might not be justified due to expansion costs. As expected, benefits of capacity expansion are greater for Wet and Warming-Only scenarios when the additional capacity can be more frequently used. The annual marginal benefit of storage capacity expansion is greatest for 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 shifting generation to higher price times.

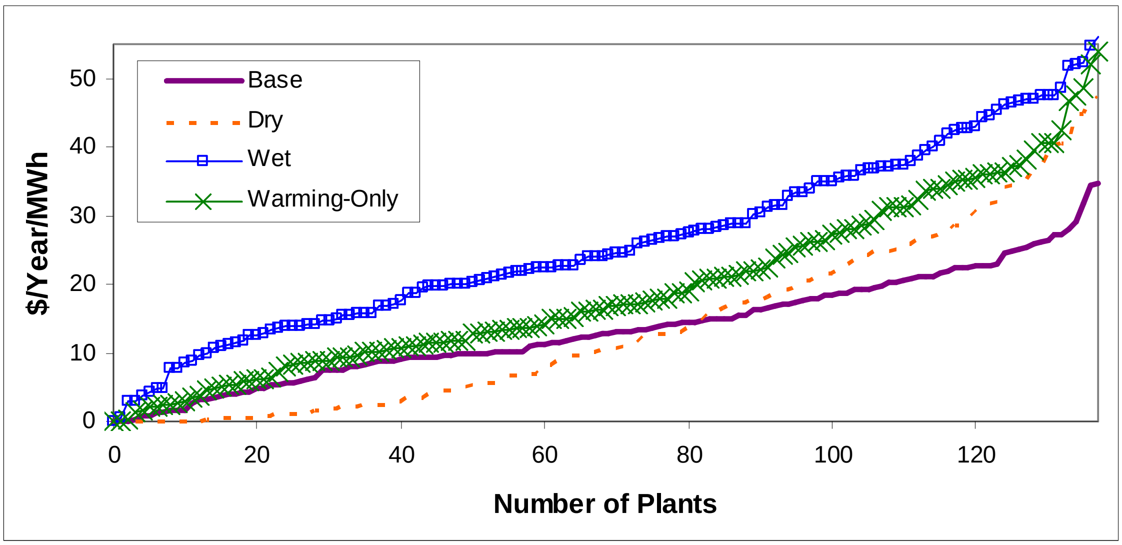


Figure 23. Average shadow price of energy storage capacity of 137 hydropower units in California in the 1985-1998 period under different climate scenarios.

Figure 24 indicates the average shadow price of energy generation (turbine) capacity (increase in annual revenue per 1 MWh of annual energy generation capacity expansion) for all 137 plants under different climate scenarios. Similar to storage capacity expansion, energy capacity expansion can increase average annual revenues for all hydropower plants under all climate scenarios. Although generation capacity expansion does not provide substantial flexibility in operations, it can reduce energy spill. Energy generation capacity is most valuable for Wet climate warming when energy spills are highest and least valuable under Dry climate warming when energy spills are least. Under a Warming-Only climate, energy generation capacity expansion value is slightly more than the base case. Even though generation capacity expansion produces benefits, expansion costs might be prohibitive.

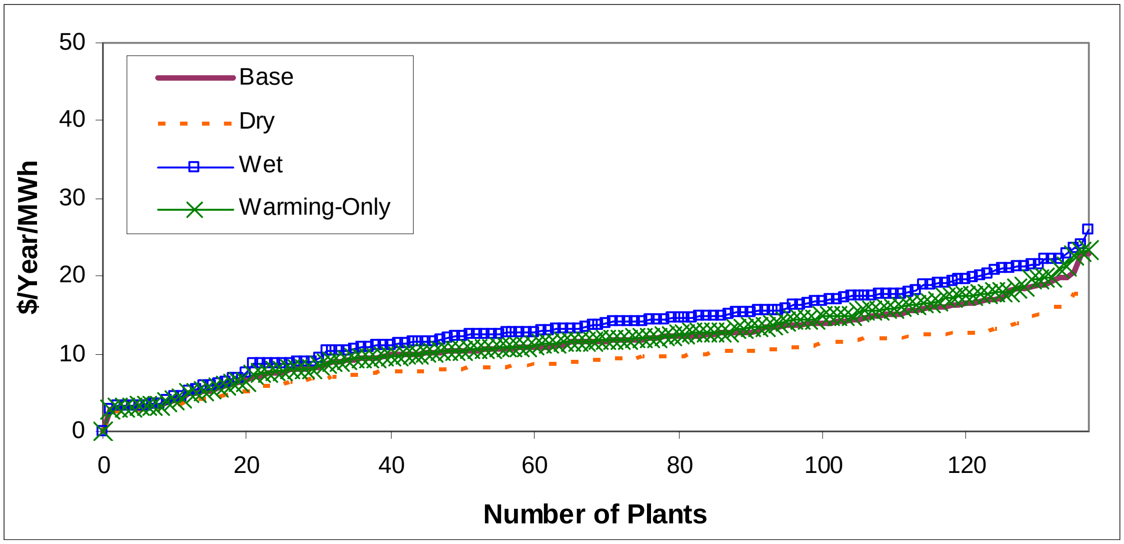
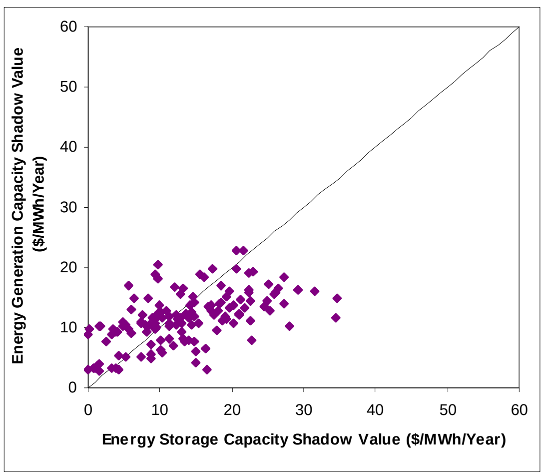


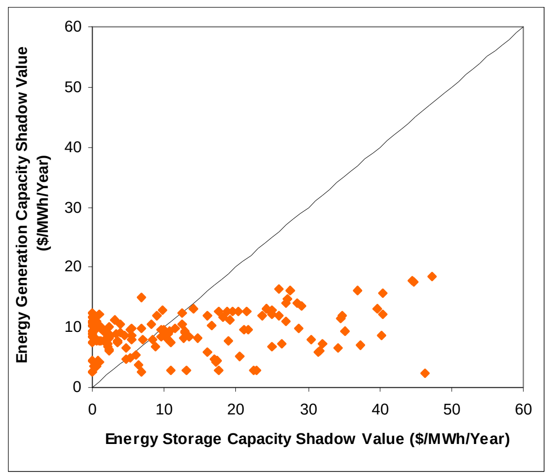
Figure 24. Average shadow price of energy generation capacity of 137 hydropower units in California in the 1985-1998 period under different climate scenarios.

Comparison of Figures 23 and 24 shows that energy storage capacity expansion is typically more beneficial than energy generation capacity expansion if the expansion costs are the same. Figure 25 clarifies that by indicating how the marginal benefits of energy storage and generation capacity expansion of power plants vary with climate. This figure also indicates the relative importance of extra energy generation and storage capacity for each unit and how that may vary with climate warming. Each point in the figure represents a powerplant. The coordinates of each point are the energy generation and storage capacity shadow prices. For the base scenario 78 power plants benefit more from energy storage capacity expansion than energy generation expansion. On average, the marginal benefit of energy storage capacity expansion is 1.20 times larger than the benefit of energy generation capacity expansion for all power plants under this scenario. Although, energy storage capacity expansion is not beneficial for 8 power plants under the Dry scenario, 79 power plants benefit more from storage than energy generation capacity expansion. Comparison of Figure 25a with Figures 25b-d shows how storage capacity becomes more valuable under climate warming as the scatter in the figures expands to the right, highlighting the higher benefit from energy storage capacity expansion than generation capacity expansion. Energy storage capacity shadow price is 1.72, 2.07, and 1.74 times higher than the energy generation shadow price for all power plants under the Dry, Wet, and Warming-Only scenarios. The number of power plants benefiting more from storage capacity expansion than generation capacity expansion reaches 122 and 101 under the Wet and Warming-Only scenarios. Under climate change, while the marginal benefit of energy generation capacity expansion almost never exceeds $25 under climate change, marginal benefit of energy storage capacity expansion can exceed $55.

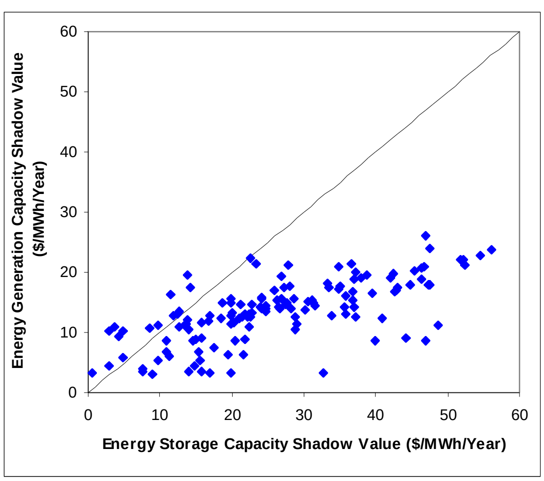
Figure 26 shows the changes of marginal benefit of energy storage and generation (turbine) capacities relative to the base (Figure 25a) case with different climate warming scenarios. Under the Dry scenario, marginal benefits of energy generation capacity of all units are lower than the base case. There is less inflow, so the existing storage and generation capacities are more often sufficient to avoid spills. For about 62 (45 percent) of plants, the value of expanding energy storage under drier conditions is more than with the base case, allowing more winter inflows to be shifted to high-value summer power generation (the maximum difference can be as high as $30). For the Wet scenario almost all units benefit from energy storage and generation capacity expansions, resulting in more generation in high-energy value months and less spills. For most units, expanding energy storage capacities is more valuable than increasing energy generation capacities with this scenario. With the Warming-Only climate, 76 units (55 percent of all units) benefit more from expanding both energy storage and generation capacities than in the base case, highlighting the importance of inflow timing for the existing system with limited storage and generation capacities.



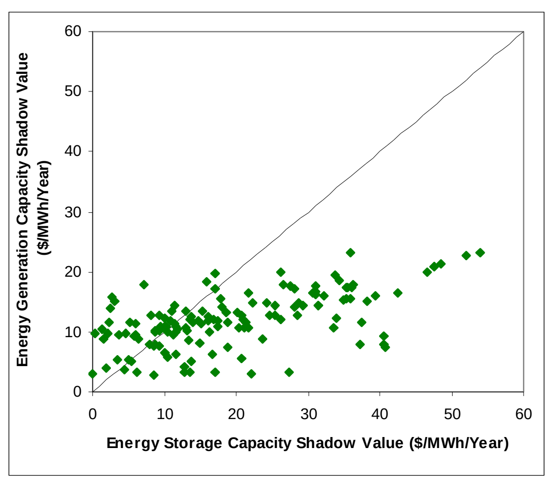
a) Base



b) Dry

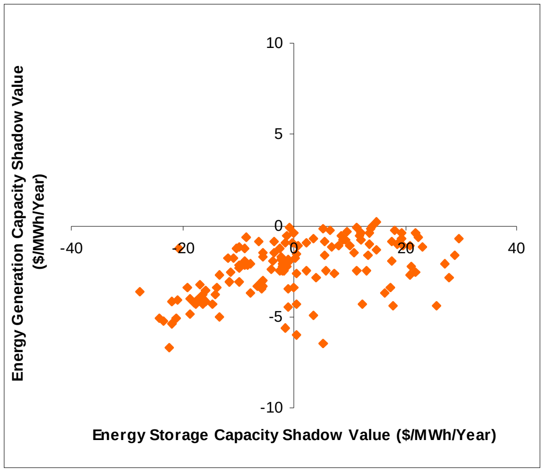


c) Wet

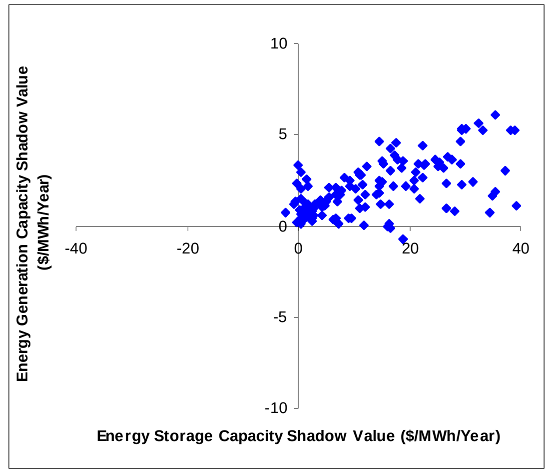


d) Warming-Only

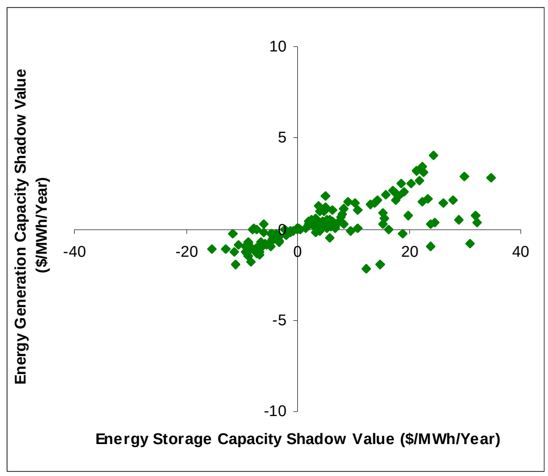
Figure 25. Average shadow values of energy storage and generation capacity of 137 hydropower units in California in the 1985-1998 period under different climate scenarios.



a) Dry



b) Wet



c) Warming-Only

Figure 26. Average change of energy storage and generation capacity shadow values from the base case with different climate scenarios (for 137 hydropower units in California in the 1985-1998 period).

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 results. However, simulation and optimization models are useful in studying resource management problems. Here, 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, in press) is likely to underestimate energy storage capacities and therefore also underestimate adaptability of the system to climate changes. 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 1,000 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 3,000-4,000 feet elevation range, it might be worthwhile to study this range separately. More gauges also 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 peak flows earlier and generate more in earlier months while higher plants generate more later in 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 energy demands and prices are likely to increase in warmer months from higher temperatures. 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 1985 to 1998. This might cause some inaccuracies in EBHOM's estimation of revenues and energy prices. However, this limitation might not affect other results (generation, spill, and storage) much as the energy price trends are similar between years. Application of longer-period price data sets 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.

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 that has functioned historically as a seasonal reservoir to delay runoff, but considerable energy storage and generation capacities remain available. The EBHOM's results show that most extra runoff in winter 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) and operating rules should change with climate warming to adapt to changes in hydrology (Medellin et al. 2008).

Generally, climate warming alone, without changes in total runoff, reduces high-elevation hydropower generation and revenue, due solely to changes in seasonal runoff timing which increase energy spill from the system due to limited energy storage and generation capacities. 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 change. 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 14 percent through optimally re-operating storage and generation facilities within existing capacities. Thus, current storage and generation capacities can compensate for some snowpack loss.

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 6 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 and almost 2 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.

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Chapter 4: FERC Relicensing and Climate Change: Insights from Game Theory

Cooperative game theory solutions can provide useful insights into how parties may use water and environmental resources and share any benefits of cooperation. Here, a method based on Nash and Nash-Harsanyi bargaining solutions is developed to explore the Federal Energy Regulatory Commission (FERC) relicensing process, in which owners of the nonfederal dams in the United States have to negotiate over the available instream water, with other interest groups (mainly environmental) downstream. Linkage of games to expand the feasible solution range and the "strategic loss" concept are discussed and a FERC relicensing barraging model is developed for studying the third stage of the relicensing process. Based on the suggested solution method, it is discussed how the lack of incentive for cooperation results in long delay in FERC relicensing in practice. Further, potential effects of climate change on the FERC relicensing are presented and it is discussed how climate change may provide an incentive for cooperation among the parties to hasten the relicensing. An "adaptive FERC license" framework is proposed, based on cooperative game theory, to improve the performance and adaptability of the system to future changes with no cost to the FERC, in face of uncertainty about future hydrological and ecological conditions.

Introduction

Nonfederal dams in the United States which generate hydroelectric power are under the regulatory authority of Federal Energy Regulatory Commission (FERC), which since 1935 has issued thousands of operation licenses (Kosnik, 2005). FERC licenses are usually valid for 30 to 50 years (FERC, 2004). To legally continue operation, the dam owner should file for a new license at the end of the initial license period. A license is a regulatory document which permits the dam owner to use public waters for hydropower generation and specifies conditions for construction, operation, and maintenance of the project (Hydropower Reform Coalition, 2009).

FERC's official statutory objective is the development of hydropower production. However, this objective should be balanced against environmental and other basin interests and implications of hydropower generation (Kosnik, 2005). Thus, FERC is forced to involve basin stakeholders and interest groups, which has strengthened the role of other interests in balancing the power benefits against the environmental effects of hydroelectric generation. Hydropower generation creates significant bioregional effects on the health of aquatic and riparian ecosystems and the periodic relicensing of hydropower facilities regulated by FERC is the only formal opportunity to reduce these impacts through new license conditions and settlement agreements that better reflect the range of modern societal goals. (Kosnik, 2005)

Table 3 presents a brief summary of the FERC relicensing process. At least five years, but not more than five and half years before the expiration of the current license, the licensee files a Notice of Intent for application for a new license (stage 1). At least a year before the expiration of the current license, licensee files a relicense application. After reviewing the application and seeking additional information or studies, upon approval, FERC formalizes it with a notice of Federal Register (stage 2). During the next stage (stage 3) a wide range of interest groups submit comments, protests, and requests for information or further studies from the licensee or FERC. This stage is the only opportunity of the concerned individuals and interest groups to affect operation of the dam through the formal regulatory process. In the final step (stage 4) FERC holds a hearing regarding the relicense application and makes its final decision. FERC decisions at this stage are important to all the stakeholders. Instead of relicensing the project, at this stage, FERC can recommend a federal takeover of the project with compensation to the current licensee or even issue a non-power license for conversion of the project to a non-hydropower use.

Table 3. Different stages of the FERC relicensing process.

Stage	***Involved Parties***	***Description***
1	Hydropower generator	The licensee files a Notice of Intent to apply for a new license (*5 to 5.5 years before expiration of the current license*).
2	FERC	FERC formalizes the relicense application with a notice of Federal Register (*1 year before expiration of the current license*)
3	Hydropower generator Environmental interest groups	Range of interests groups submit comments, protests, and requests for information or further studies from the licensee or FERC. This stage is the only opportunity for concerned individuals and groups to affect operations of the dam through the formal regulatory process. Interested parties can come up with compromise plans through bargaining (expected to be completed by 5 years)
4	FERC Hydropower generator Environmental interest groups	FERC holds a hearing regarding the relicense application and makes its final decision.

The official relicensing process is expected to average five years to completion. However, 27 percent of licenses issued by FERC between 1982 and 1988 took the expected 5 years, with the longest requiring 21 years to complete (Kosnik, 2005). In recent years applications tend to languish longer. Most variability in processing time is associated with stage 3 of relicensing. The final decision is up to FERC, but agreements among stakeholders at stage 3 can accelerate the process significantly (Kosnik, 2005).

With many projects facing re-licensing in the United States by 2020 (more than 150 projects in California), FERC relicensing will be complicated, lengthy and resource-intensive. This problem can be exacerbated by expected climate changes with significant implications for various environmental resources and ecosystems, as well as hydropower production. Although changes in operation may help adaptation to new climatic conditions and minimize revenue losses to some extent, environmental constraints, imposed on operations by FERC as a result of pressure by the interest groups might limit flexibility.

It is important to interest groups and environmental advocates that long-term licenses and agreements can address changes and reduce the likelihood that operations will produce irreversible ecosystem impacts before subsequent license renewals. Thus, they take as much effort as possible in stage 3. Generally, environmental interest groups are expected to seek to hasten the process (independent of final relicensing outcome) to save endangered riverine resources while dam owners and hydropower investors are mostly seeking to slow down process to postpone financially constraining environmental mitigation requirements. However, climate change may reverse this trend as environmental and revenue losses may provide an incentive for cooperation to speed license renewal in coming decades.

Cooperative game theory is applied in this study as a useful method for understanding causes of delay in stage 3 of FERC relicensing in general and exploring why fixed terms of a FERC license might deteriorate the performance of the hydropower system and its environment under climate change. Cooperative game theory has been previously used in studying water and environmental resources conflicts (Gately, 1974; Straffin and Heaney, 1981; Young et al., 1981; Szidarovszky et al., 1984; Kilgour et al., 1988; Dinar et al., 1992; Dinar and Wolf, 1994; Lejano and Davos, 1995; Dinar and Howitt, 1997; Lippai and Heaney, 2000; Kucukmehmetoglu and Guldmann, 2004; Wu and Whittington, 2006; Salazar et al., 2007; and Wang et al, 2008). Cooperative game theory solutions or stability definitions including Core (Gillies, 1953), Nash bargaining solution (Nash, 1953), Shapley value (Shapley, 1953), Nash-Harsanyi solution (Harsanyi, 1953 and 1963), Nucleolus (Schmeidler, 1969), Kalai-Smorodinski solution (Kalai and Smorodinsky, 1975), and τ - value (Tijs, 1981) can provide useful insights into how interests plan their use of water and environmental resources and find a method for sharing gains from cooperation.

This chapter suggests a cooperative game theoretic method based on Nash and Nash-Harsanyi bargaining solutions for gaining insights and finding the conditions under which parties to a FERC license are willing to cooperate to issue a new license. The strategic loss concept is discussed and a revision to the Nash and Nash-Harsanyi stability definitions is suggested to make them applicable to a linked game upon which a FERC relicensing bargaining model is developed. The method suggested here can provide insights into stage 3 of FERC relicensing - the most complicated stage. The FERC relicensing bargaining model can support ongoing bargaining and negotiations of the interested parties and may be used to investigate if climate change can be an incentive for cooperation and speeding the relicensing. Further, the paper suggests a bargaining framework to be added to FERC licenses to provide more flexibility and adaptability to climate change.

Revising the Nash Bargaining Solution for Connected Games

Nash (1953) found Ω as a unique solution to the 2-player bargaining game under certain axioms:

$$\Omega = \max(x_1 - d_1)(x_2 - d_2) \qquad (1)$$

subject to:

$$\sum_{i=1}^{2} x_i \le S \qquad (2)$$

$$x_i \ge d_i \qquad (3)$$

$$x_i\,,\ d_i \ge 0 \qquad (4)$$

where for player $i=1, 2$:

x_i= share of player i under cooperation; d_i= share of player i when acting individually (non-cooperation case); and S= total available resource. Setting $d_i=0$, x_i will be the gain of player i from coalition.

Harsanyi (1959 and 1963) generalized Nash solution for 2-players bargaining game to an n-players game:

$$\Omega = \max \prod_{i=1}^{n} (x_i - d_i) \qquad (5)$$

subject to:

$$\sum_{i=1}^{n} x_i \le S \qquad (6)$$

$$x_i \geq d_i \qquad (7)$$

$$x_i\,,\, d_i \geq 0 \qquad (8)$$

Just and Netanyahu (2004) showed how the feasible set can be expanded through connecting isolated games, even otherwise irrelevant non-cooperative games. Since bargaining over one issue might not always result in a cooperative resolution (when Ω=0) it might benefit negotiators to bargain over several issues at the same time. The feasible set is expanded in this case because outcomes that are not desired in isolated games due to individual rationality constraints may become desired when compensated by offsetting gains from connected issues. Interconnection is only beneficial when each party is stronger than the other in one of the sub-games. In such cases, one party is willing to lose in one game to gain in the other. A Nash solution for a 2 player bargaining game can be written for *k* linked 2-player games as:

$$\Omega = \max\left(\sum_{j=1}^{k} x_{1,j} - d_{1,j}\right)\left(\sum_{j=1}^{k} x_{2,j} - d_{2,j}\right) \qquad (9)$$

subject to:

$$\sum_{i=1}^{2} x_{i,j} \leq S_j \qquad (10)$$

$$\sum_{j=1}^{k} x_{i,j} \geq \sum_{j=1}^{k} d_{i,j} \qquad (11)$$

$$x_{i,j}\,,\, d_{i,j} \geq 0 \qquad (12)$$

where for player *i=1,2:*

$x_{i,j}$= share of player i in the j[th] sub-game (j= $1,2,\ \ldots,\ k$) when parties cooperate in the linked game ; $d_{i,j}$= share of player i when acting individually (non-cooperation case) in the j[th] sub-game ; and S_j= total available resource in sub-game j. Setting $d_{i,j}=0$ ($\sum_{j=1}^{k} d_{i,j}=0$), $\sum_{j=1}^{k} x_{i,j}$ will be the gain of player i from cooperation.

Similarly, the Nash- Harsanyi solution for for k linked n-player games becomes:

$$\Omega = \max \prod_{i=1}^{n} \left(\sum_{j=1}^{k} x_{i,j} - d_{i,j}\right) \qquad (13)$$

subject to:

$$\sum_{i=1}^{n} x_{i,j} \le S_j \qquad (14)$$

$$\sum_{j=1}^{k} x_{i,j} \ge \sum_{j=1}^{k} d_{i,j} \qquad (15)$$

$$x_{i,j}\ ,\ d_{i,j} \ge 0 \qquad (16)$$

for player $i=1,2,\ \ldots,\ n$.

If $\Omega>0$ and there exists a j for which $x_{i,j} < d_{i,j}$, player i is a "strategic loser" in game j. This player is willing to lose in game j when he knows his loss in game j keeps him in the coalition and his gain from cooperation in the larger game (composed of k interconnected games) exceeds his overall gain from k isolated games. Player i gains less when he plays each game independently and is not willing to lose in any game to gain in others. Strategic loss for one may exist to players of the larger (interconnected) game when each player is stronger than the others at least in one of the sub-games. Willingness for "strategic loss in cooperation" expands the feasible solution set to the bargaining game where if k separated games are played by player *i*, there will be no strategic loss, and the final solution will be inferior to a solution to the linked game.

FERC Relicensing Bargaining Game

At stage 3 of re-licensing, environmental groups and hydropower generators, respectively, are expected to hasten and slow the process. However, empirical results show that in practice both groups of interveners are significantly effective at slowing the process (Kosnik, 2005). With help from the Nash solution for this game it is possible to find why the parties might lack incentive to cooperate, resulting in delay in stage 3.

The third stage of FERC relicensing can be modeled as a bargaining game where two players- the hydropower generator and a coalition of environmental interest groups at a given site- bargain to increase their benefit from the available water. $d_{env,\ j}$ and $d_{hp,\ j}$, respectively, are the gains of environmentalists and the hydropower generator in time *j* from their shares based on the current license (the parties have regulated shares at any period *j* based on the current operations and environmental constraints imposed by the existing license). In this game, a hydropower generator wants to operate the dam to maximize his revenue, while environmentalists want the dam to be operated to maximize their utility (sportfishing, boating, historical, endangered species, water quality, and recreation).

In the third stage of FERC relicensing, the two players do not bargain over their shares in a given time step in isolation from other time periods as they know without interconnection of the k independent games, it is impossible to find any superior solution. Thus, the parties always consider a larger (e.g. annual) game and do not bargain over their share only in time j (e.g. hour, day, week, month, or season) without considering their shares in other periods. The Nash Bargaining Solution for the third stage of the FERC relicensing game should be written as:

$$\Omega = \max\left(\sum_{j=1}^{k} U_j(x_{env,j}) - U_j(d_{env,j})\right)\left(\sum_{j=1}^{k} R_j(x_{hyd,j}) - R_j(d_{hyd,j})\right) \quad (17)$$

subject to individual rationality and resources availability constraints, where for player *i=Environmentalists, Hydropower Operator* and time step $j=1,2,\ \ldots,\ k$:

$U(x_{env,j})$ = utility of the environmentalists in cooperative case at time j from their share $x_{env,j}$; $U(d_{env,j})$ = utility of the environmentalists in non-cooperative case at time j from their regulated share $d_{env,j}$; $R(x_{hyd,j})$ = revenue of the hydropower generator in cooperative case at time j from its share $x_{hyd,j}$; $R(d_{hyd,j})$ = revenue of the hydropower generator in non-cooperative case at time j from its regulated share $d_{hyd,j}$.

For a dam like the one in Figure 27 with turbines below the dam and no diversion tunnel, $x_{env,j} = x_{hyd,j}$ and $d_{env,j} = d_{hyd,j}$, because the amount of water through the turbine flows in the stream.

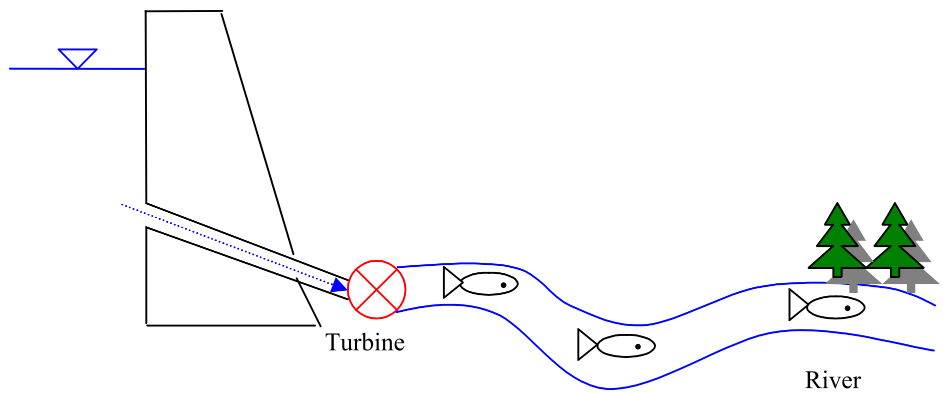

Figure 27. Hydropower generation site without a diversion unit.

Modeling stage 3 of the FERC relicensing game using cooperative game theory enables us to find if cooperation between the parties is possible and if so, what flow values bring collaboration between the conflicting parties. If $\Omega > 0$ then there exists a j for which one of the payers is a strategic loser ($U(x_{env,j}) < U(d_{env,j})$ or $R(x_{hp,j}) < R(d_{hp,j})$) and is willing to lose in period j to increase its gain in the overall interconnected game. However, If $\Omega = 0$ is the only solution to equation 17, the parties are not willing to cooperate because they cannot come up with any compromise solution. In bargaining games like this, a player does not cooperate and the conflict has no cooperative resolution if he does not receive at least as much as he can get in the non-cooperative game. This can cause a long a delay in FERC relicensing. In such cases, cooperation is not the parties' dominant strategy and is not beneficial to the players. Thus, when unsuccessful in bargaining based on Equation 17, the hydroelectricity generator tries to delay the process to preserve its current generation pattern and capacity and avoid costly environmental mitigation requirements (as long as the new license is not issued and FERC has not made its decision, operations will be based on the current license). On the other hand, the environmental interest groups who are unsuccessful in making the generators cooperate, seek to delay the process to ensure their interests are finally implemented through methods other than bargaining such as asking for assistance from the congress or FERC through formal regulatory and legal processes.

When $\Omega = 0$, delaying is the dominant strategy, and when $\Omega > 0$, parties tend to cooperate. One benefit of using cooperative game theory for studying FERC relicensing is the ability of finding flow values for each time step, which makes cooperation possible when parties prefer to cooperate. Agreement on enforcing such numbers by the terms and conditions of the FERC license can make cooperation possible when both parties can gain more (win-win situation). To show how Equation 17 can be used to find if cooperation or delaying is the dominant strategy to players, a numerical example is presented.

FERC Relicensing Bargaining Model

Suppose a group of environmentalists below the Aab-Band Dam on Ravan River and the operators of this single-purpose high-elevation hydropower reservoir with no diversion unit and no carry-over storage (Figure 27), are in the FERC relicensing process. The environmentalist group is concerned with the effects of reservoir operations and changes in stream flows and temperatures on the population of Kuchulu fish in Ravan River and are negotiating over the monthly insteram flows with the dam operators. Currently, the reservoir is operated based on the terms and conditions of the existing license which has been in use for the past 25 years. These terms and conditions include the minimum and maximum monthly stream flows (Figure 28) for maximizing the Kuchulu fish survival rate. The capacity of Aab-Band reservoir is 140 million cubic meters with the turbine generation capacity of 1,528 MWh per month.

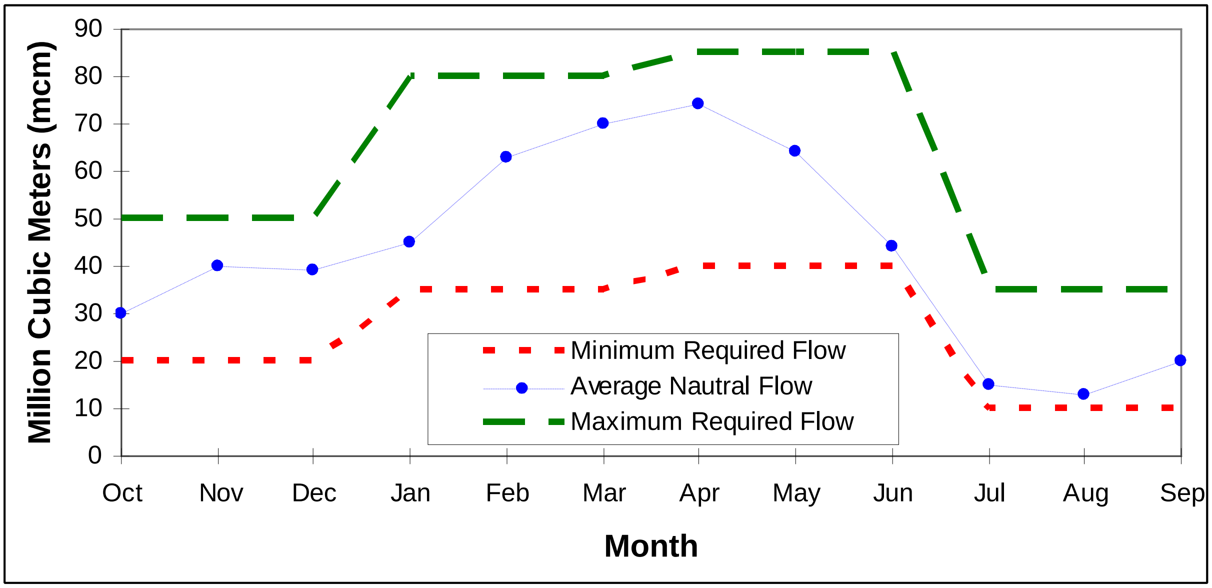

Figure 28. Monthly unimpaired flow regime of Ravan River and minimum and maximum flow requirements below the Aab-Band Dam

The benefit and utility to each party in each month should be specified for use in Equation 17. Monthly revenue to the hydropower generator can be calculated, from hydropower prices and generation. Madani and Lund (in press) developed a method for incorporating the effects of off-peak and on-peak pricing on hydropower generation. This method, which has been used in California's EBHOM (Energy-Based Hydropower Optimization Model), estimates the average monthly hydropower price based on the hours of turbine operation or proportion of monthly generation capacity used. This method is used here for incorporating the non-linear relationship of hydropower generation and pricing. Real-time hourly hydropower prices across California were used to estimate the hydropower prices based on the proportion of generation capacity used. Using this method, monthly hydropower revenue can be calculated as:

$$Z_j(G_j) = P_j(g_j) \times G_j \qquad (18)$$

where:

Z_j = hydropower revenue in month j; G_j = hydropower generation in month j (MWh/month); g_j = the proportion of monthly generation capacity used ($g_j = \frac{G_j}{G_{cap}}$); and $P_j (g_j)$ = price of electricity in month j (\$/MWh) when generation is equal to g_j.

The Aab-Band reservoir is operated for revenue maximization (hydropower operating costs are essentially fixed at monthly scale), based on the following hydropower optimization model (Equations 19-29):

$$Max\ Z = \sum_{j=1}^{12} Z_j(G_j) \qquad (19)$$

subject to:

$$S_1 = big \text{ (initial condition)} \qquad (20)$$

$$S_{min} \leq S_j ,\ \forall j \qquad (21)$$

$$S_j \leq S_{max,}\ \forall j \qquad (22)$$

$$S_{max,} - S_{min} \leq Scap \text{ (storage capacity constraint)} \qquad (23)$$

$$S_j = I_{j-1} + S_{j-1} - R_{j-1} \text{ (conservation of mass)},\ \forall j \qquad (24)$$

$$G_i \leq R_j \times h \times \lambda,\ \forall j \qquad (25)$$

$$G_i \leq Gcap \text{ (generation capacity constraint)},\ \forall j \qquad (26)$$

$$R_j \leq R_{max,\, j},\ \forall j \qquad (27)$$

$$R_{min,\, j} \leq R_j,,\ \forall j \qquad (28)$$

$$G_j ,\ S_j ,\ R_j \geq 0 \text{ (non-negativity)},\ \forall j \qquad (29)$$

where for $j = 1, 2, 3, \ldots, 12$:

Z = annual hydropower benefit; S_j = water storage at the beginning of month j (m^3) (a decision variable); $Scap$ = reservoir storage capacity (m^3); big = an arbitrary large number greater than or equal to $Scap$; S_{min} = minimum monthly water storage during the year (12 months period) (m^3) (a decision variable); S_{max} = maximum monthly water storage during the year (m^3) (a decision variable); I_j = inflow to reservoir (upstream runoff) in month j (m^3/s); R_j = water release from the reservoir in month j (m^3/s) (a decision variable); $R_{min,\, j}$ = minimum release (instream flow) in month j, enforced by the FERC license (m^3/s) (a decision variable); $R_{max,\, j}$ = maximum release (instream flow) in month j, enforced by the FERC license (m^3/s) (a decision variable); $Gcap$ = generation capacity (MWh/month); h = turbine head (m); and λ = turbine efficiency.

The head-storage effect is minimal in high-elevation reservoirs (Madani and Lund, in press), so energy head is assumed constant across all months (Equation 26). Conventionally, in hydropower operation model storage at beginning of one month is set to zero (initial condition). However, by doing this optimal refill and drawdown cycles may not be found unless the model is run 12 times, each time by a different initial month. Equations 20-23, suggested by Madani and Lund (in press), allows finding the optimal operations and drawdown and refill cycles with only one model run. The Aab-Band hydropower system has no carry-over storage. Thus, operation decisions in each year are independent from other years. Minimum and maximum monthly stream flows below the reservoir are set by the existing FERC license and as long as a license has not been renewed, they do not change. Figure 29 indicate the optimal monthly hydropower generation and revenues for the average natural stream flows based on the existing FERC license. The total annual hydropower revenue with average natural inflows based on the current license is $ 578,746 (Equation 19).

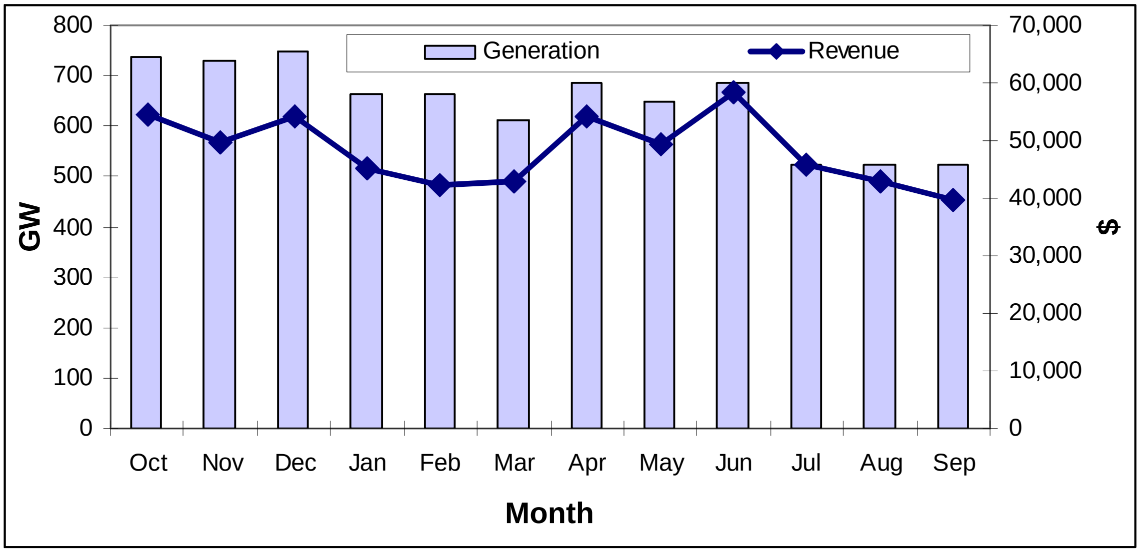

Figure 29. Optimal monthly hydropower generation and revenues based on the existing license.

Calculating utilities for the environmentalist group is more controversial. Here, it is assumed that the highest fish survival is with the unimpaired flow (Figure 28). Any deviation from the natural flow regime reduces the fish population. Monthly fish population penalties are defined as:

$$FP_j(R_j) = w_j \times \left| R_j - R_{n,j} \right|^2 \qquad (30)$$

where for (j = 1, 2, ..., 12):

FP_j = fish penalty in month j; $R_{n,j}$ = historic average natural flow of the river; and w_j = weight of penalty in month j.

It is assumed that the environmentalist group is trying to minimize total annual penalties, maximizing the Kuchulu fish population through the downstream flow requirements. The parties have agreed on such requirements and during the past 25 years they have been enforced by the FERC license of Aab-Band project. The deviation in instream flow below the dam increases the fish penalty exponentially. Fish penalties vary across the months for the same amount of flow deviation from the natural stream flow, as juvenile fish are more sensitive than adult fish to flow changes. Therefore, monthly weights (Table 4) are assigned to fish penalties where the weights decrease as fish age. Figure 30 shows calculated monthly fish penalties for the optimal hydropower generation based on the current FERC license (Equation 30). The annual fish penalty (FP) for the current operations based on the existing license is the sum of the monthly fish penalties:

$$FP = \sum_{j=1}^{12} FP_j(R_j) \qquad (31)$$

which is equal to 3.25.

Now, the parties are in the third stage of the FERC relicensing, negotiating over the monthly instream flows. Based on Equation 17, it is possible to find if the two players are willing to cooperate and agree over new sets of monthly instream flows and changes in operations required to make cooperation possible. Considering Equations 17-30, the FERC relicensing bargaining model for the Aab-Band project is as follows:

Table 4. Monthly fish penalty weights

Month	*Fish Penalty Weights*
Oct	0.35
Nov	0.35
Dec	0.35
Jan	1.00
Feb	1.00
Mar	1.00
Apr	0.80
May	0.80
Jun	0.80
Jul	0.50
Aug	0.50
Sep	0.50

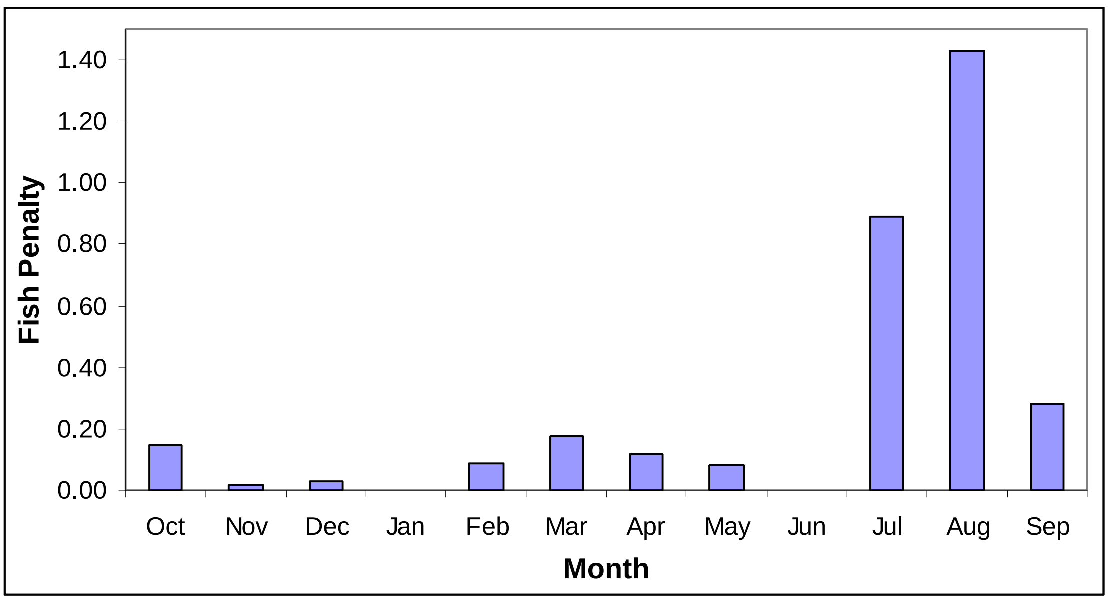

Figure 30. Monthly fish penalties for the optimal hydropower operations based on the current license.

$$Z_{old} \leq \sum_{j=1}^{12} Z_j(G_j) \quad (32)$$

subject to:

$$\sum_{j=1}^{12} FP_j(R_j) \leq FP_{old} \text{ (rationality condition)} \qquad (33)$$

$$Z_{old} \leq \sum_{j=1}^{12} Z_j(G_j) \text{ (rationality condition)} \qquad (34)$$

Equation 18

Equations 20-26

Equations 29-30

where for $j = 1, 2, 3, \ldots, 12$:

FP_{old} = annual fish penalty for current optimal hydropower operations based on the current license (Equation 31); and Z_{old} = maximum annual hydropower revenue based on the current license (Equation 19).

Equations 27 and 28 (requirements of the old FERC license) were not put in the FERC relicensing bargaining model, as using them limits the feasible set and the results will not be anything other than zero. By not including them, the feasible bargaining set is expanded and the parties might find a solution preferred by both.

The only solution to the FERC relicensing bargaining model in the Aab-Band case is $\Omega = 0$, so similar to most parties to the FERC relicensing processes in the United States, no immediate cooperative solution is available to the environmentalists and hydropower operator in this example and there may be a long delay in stage 3 of FERC relicensing.

The bargaining model developed here can provide insights into FERC relicensing projects. This model can support the third stage of FERC relicensing as a Negotiation Support System (NSS) to suggest cooperative solutions under different conditions. FERC bargaining games do not always have a non-cooperative solution ($\Omega = 0$). Changes in conditions of the problem (e.g. turbine generation capacity, reservoir storage capacity, natural flow regime, hydropower prices, and fish penalties) over time are likely. Such changes may result in cooperative solutions ($\Omega > 0$). For instance, if recent studies suggest that fish penalties differ from what would have estimated earlier due to biological change in the fish, the change in the fish penalty weights or functions might result in new solutions to the FERC relicensing problem. For the Aab-Band project, if Kuchulu fish penalties change to those given in Table 5, the FERC relicensing bargaining model has a solution $\Omega > 0$, preferred by both parties. In this case, the parties may decide to cooperate and agree on new sets of monthly instream flows (enforced through the FERC license), or wait to gain better solutions in the future through other methods (e.g. asking for assistance from the congress or FERC through formal regulatory and legal processes). Table 4 shows the gains of each party when new fish penalty weights are applied. Although hydropower operator benefit does not increase significantly with cooperation, the risk of future reduction in revenues decreases when the operator is willing to cooperate to finalize the third stage of the process to get a new license. Figures 31, 32, and 33 show monthly hydropower generation, hydropower revenues, and fish penalties under non-cooperative and cooperative cases when new fish penalty weights are applied. These figures show how linking the 12 monthly games is useful and how strategic loss can result in more gain in the larger game. Here, the hydropower generator reduces its generation in half the year for more generation in the other half. This makes the hydropower generator a strategic loser in half of the year and a winner in the other half, with higher overall gain. On the other hand, the environmentalists are strategic loser in 3 months and winner in 9 months, with overall annual fish penalty reduction of 2 percent under cooperation (Table 6).

Table 5. New monthly fish penalty weights due to biological evolution of the fish.

Month	*Fish Penalty Weights*
Oct	0.40
Nov	0.40
Dec	0.40
Jan	0.90
Feb	0.90
Mar	0.90
Apr	0.80
May	0.80
Jun	0.80
Jul	0.70
Aug	0.70
Sep	0.70

Table 6. Gains of each party with the old and new fish penalty weights

Case Description	*Fish Penalty*	*Hydropower Revenue*
Operations based on the existing license (original fish penalty weights)	3.25	$ 578,746
Operations based on the existing license (new fish penalty weights)	4.29	$ 578,746
Operations based on the new agreement (new fish penalty weights)	4.21	$ 578,880

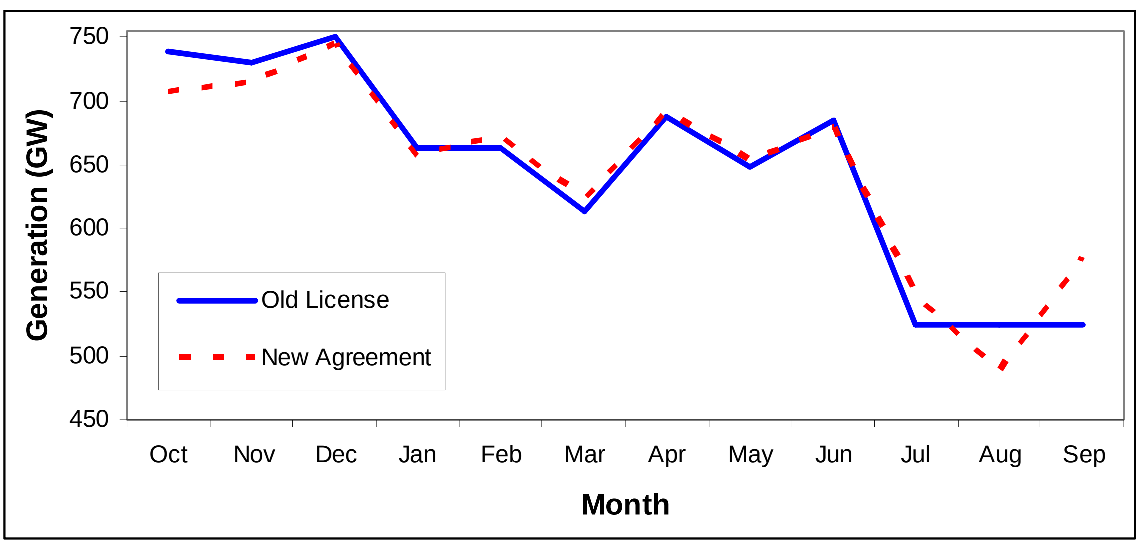

Figure 31. Monthly hydropower generation with new fish penalty weights based on the old license (no-cooperation) and the new agreement (cooperation).

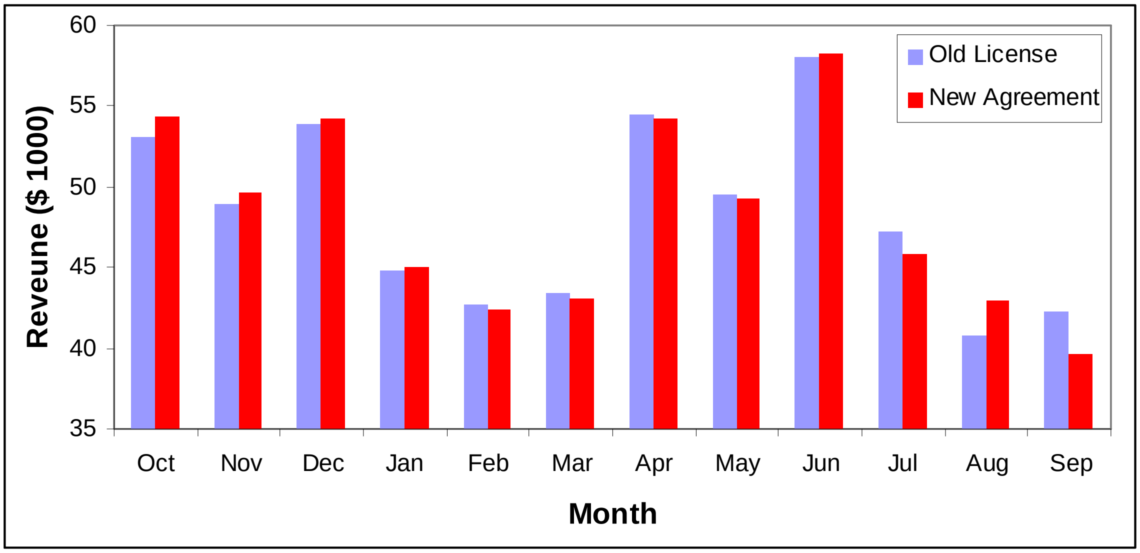

Figure 32. Monthly hydropower revenue with new fish penalty weights based on the old license (no-cooperation) and the new agreement (cooperation).

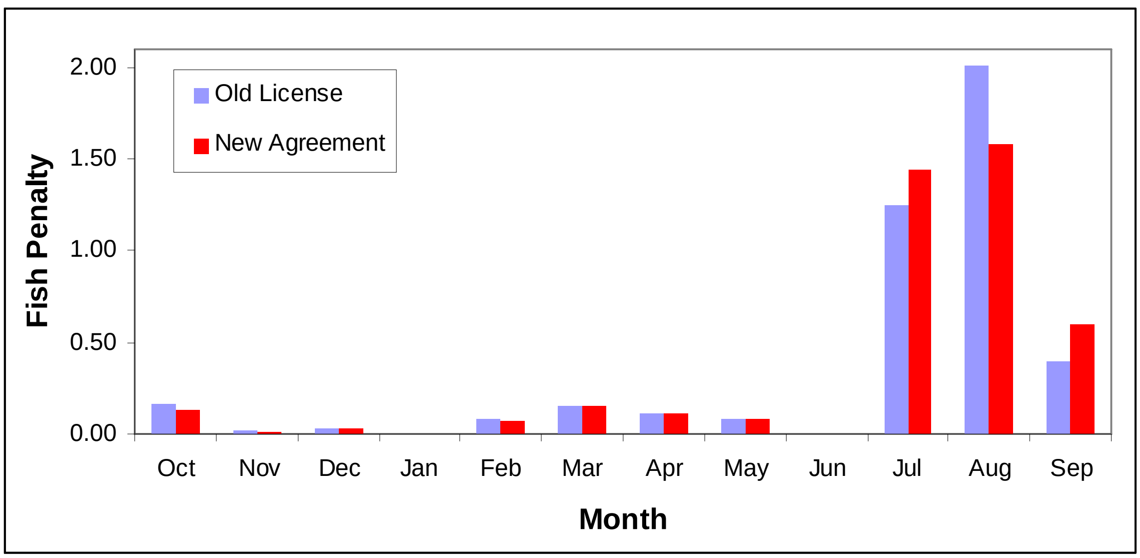

Figure 33. Monthly fish penalties with new fish penalty weights based on the old license (no-cooperation) and the new agreement (cooperation).

Figure 34 shows how the optimal trade-off curve (Pareto-optimal surface) and the optimal solution to the bargaining game can change with changes in the problem. If current operations are at point A, the bargaining game has a solution ($\Omega > 0$) which under cooperation results in Pareto-optimal operations at point B. In that case, point A is Paretoinferior. If the current operations are at point B, with no change in the conditions of the problem, the game has no solution ($\Omega = 0$), the parties have no incentive for cooperation, and delaying is a dominant strategy of both players. Under changes in conditions, the new optimal surface may move. The same operations which would have resulted in point B earlier may result in point C due to changes in the problem (e.g. keeping the old operations when fish penalties change, can reduce fish benefits). However, under cooperation point C becomes inferior to point D which is the new optimal solution of the bargaining game ($\Omega > 0$) located on the new optimal trade-off curve.

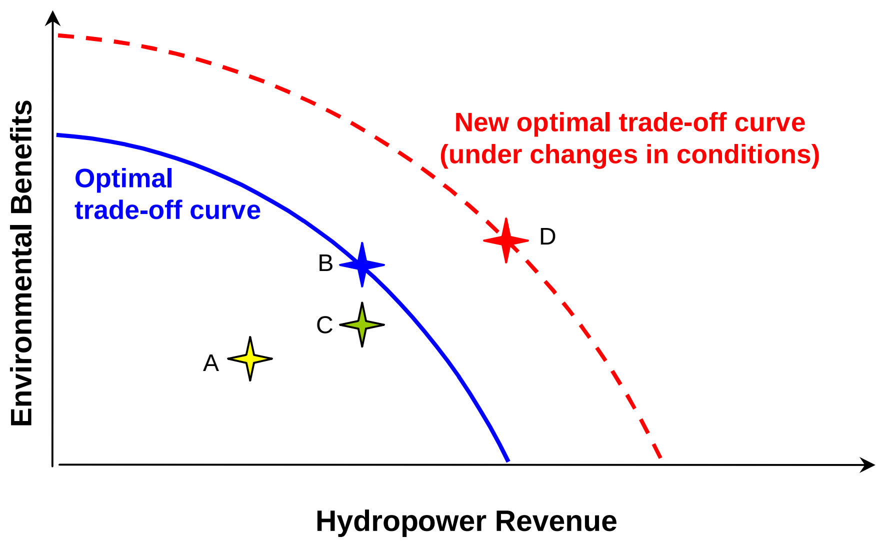

Figure 34. Trade-off between fish penalties and hydropower revenue with old and new conditions

FERC Relicensing and Climate Change

Climate change is anticipated, with a global temperature increase of 2.5ºF to 10.4ºF by 2100 (Pew Center on Global Climate Change, 2009). Climate change can result in changes in various conditions such as flow timing and quantity, temperature, biological changes, fish responses, etc. for FERC projects. Riverine ecosystems of any bioregion are determined by climatic conditions, particularly precipitation and temperature. Changes in precipitation can cause significant changes in riverine plant and animal communities. Various studies (Miles et al., 2000; Casola et al., 2005; Medellin et al., 2008; Vicuna et al., 2008; Madani and Lund, in review) also have found hydropower operations across the United States to be sensitive to climate change.

License terms usually are fixed and do not change until the next license is issued. Operation under changing climatic conditions based on the fixed license terms is challenging for operators and may result in revenue losses. On the other hand, the environmental constraints available in the license may not maximize environmental benefits under changing conditions as the biological and ecological responses may not be known at the time of license issuance.

The FERC relicensing bargaining model can help find if climate change can provide an incentive for cooperation of the parties for speeding up the third stage of the FERC relicensing process. Changes in conditions for FERC relicensing may move the optimal trade-off curve (Figure 35) and make the optimal operations and solution (Point A) based on the conditions of the current license infeasible or suboptimal (Point B). In that case, the bargaining model finds a new optimal solution ($\Omega > 0$) (Point C). Since operations are based on the terms of the current license as long as a new license has not been issued, under hydrological changes when $\Omega > 0$, delaying (non-cooperative strategy) is not the dominant strategy for the player and both parties are willing to cooperate to minimize losses from delaying the license renewal.

For the Aab-Band project, if the reservoir inflow changes due to climate change (Figure 36) (assuming that fish penalties and hydropower prices do not change), the hydropower operator responds adaptively by changing the operations, based on the hydropower optimization model (Equations 19-29), to minimize the revenue losses due to climate change. Figures 37 and 38 show the optimal operations of Aab-Band reservoir, hydropower revenues, and fish penalties under climate change, when operations are based on current license. Comparing these figures with Figures 29 and 30 shows how the hydropower generation trend, its revenues and its effects on fish resources change with climate change. Total hydropower revenue and fish penalty before and after climate change are given in Table 7. Reduction of annual inflows by 24 percent drops annual revenues 18 percent and a substantial increase in fish penalties.

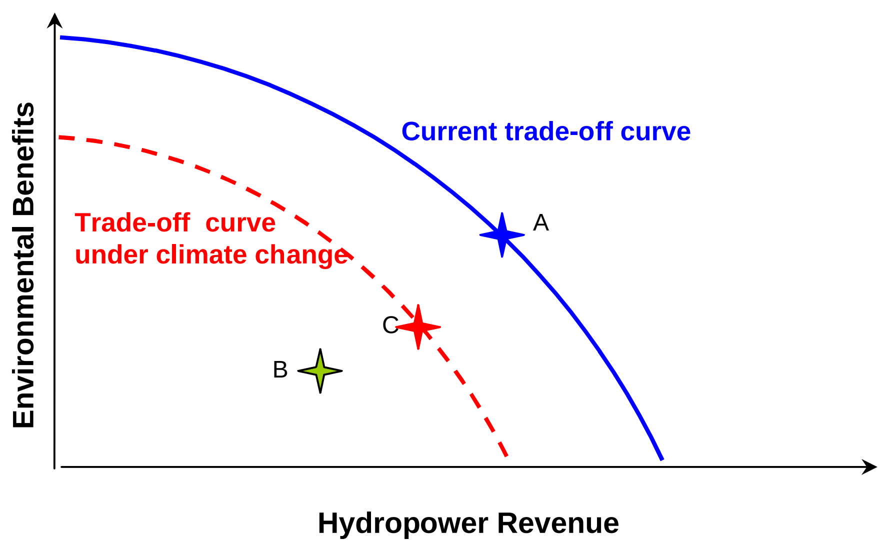

Figure 35. Trade-off between the fish penalties and hydropower revenue with and without climate warming

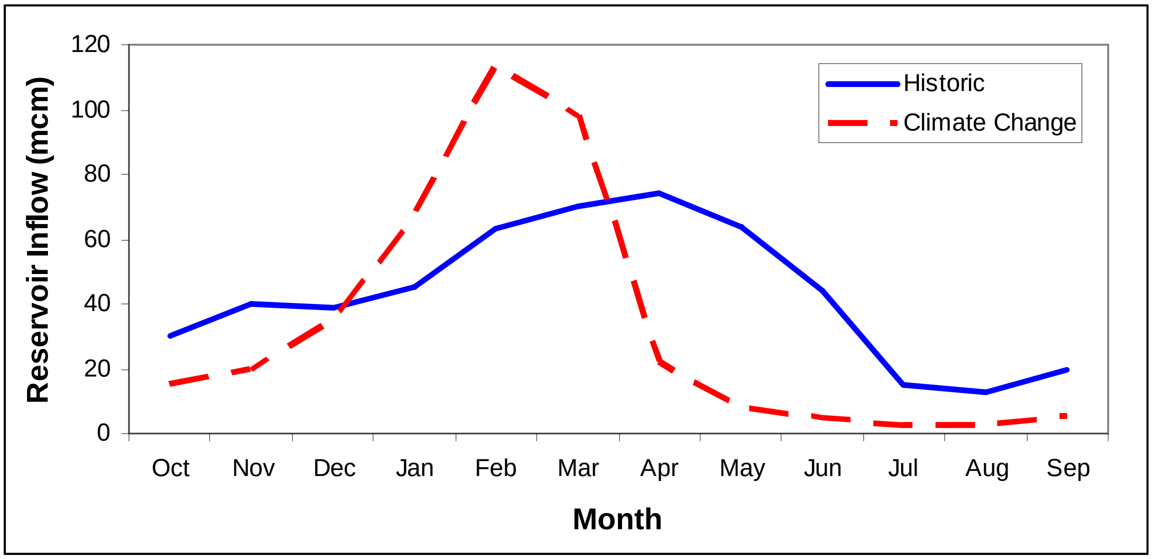

Figure 36. Average monthly inflows to Aab-Band reservoir under different climate scenarios.

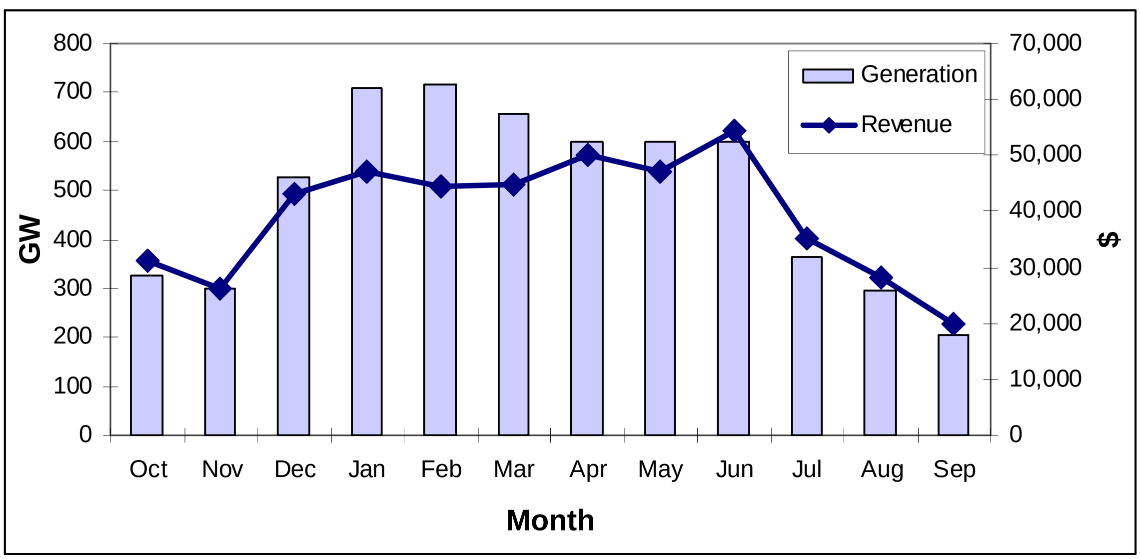

Figure 37. Optimal monthly hydropower generation and revenues under climate change based on the existing license.

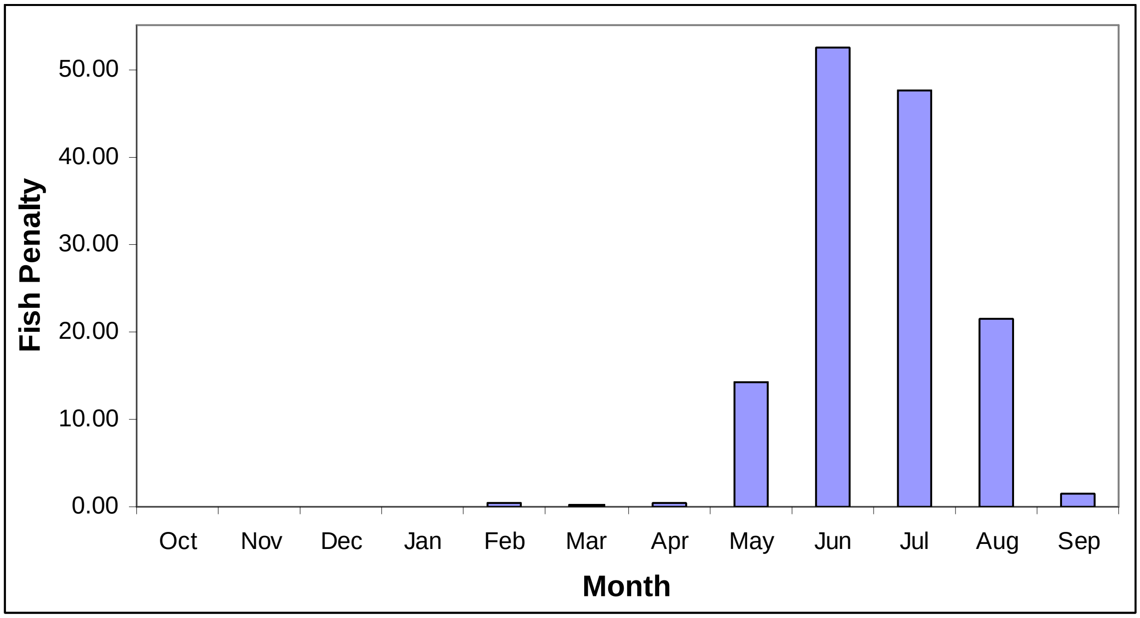

Figure 38. Monthly fish penalties for the optimal hydropower operations under climate change based on the current license.

Table 7. Gains of each party with under different climate scenarios.

Case Description	*Fish Penalty*	*Hydropower Revenue*
Operations based on the existing license (with historic climate)	3.25	$ 578,746
Operations based on the existing license (with climate change)	138.27	$ 471,735
Operations based on the new agreement (with climate change)	92.45	$ 475,504

Under climate change, the hydropower operator loses some revenues, but has to keep the operations based on the existing license. On the other hand, fish penalties will be higher with climate change. In such conditions, a FERC license with new terms and conditions may improve results for both players under climate change, relative to their results with the old license. When the total hydropower revenue and fish penalty under climate change is used in the FERC relicensing bargaining model and the minimum and maximum insteram flow requirements are relaxed, a new solution is found which benefits both players ($\Omega > 0$). Therefore, climate change can be an incentive for cooperation. To minimize losses, both parties are willing to hasten a new license with new terms and conditions for downstream flows. Table 7 shows the total hydropower revenue and fish penalty under climate change when the parties are willing to cooperate. Figures 39, 40, and 41 indicate the monthly hydropower generation and the gains of each party under non-cooperative and cooperative cases for climate change. Under cooperation, the hydropower generator is a strategic loser in 4 months, reducing its generation and revenue in exchange for higher generation and revenue in 4 other months, keeping generation and revenue equal the rest of the year with higher overall annual revenues. On the other hand, fish penalties increase/decrease (environmentalists strategically lose/win) whenever hydropower generation increases/decreases, making cooperation desirable for both parties.

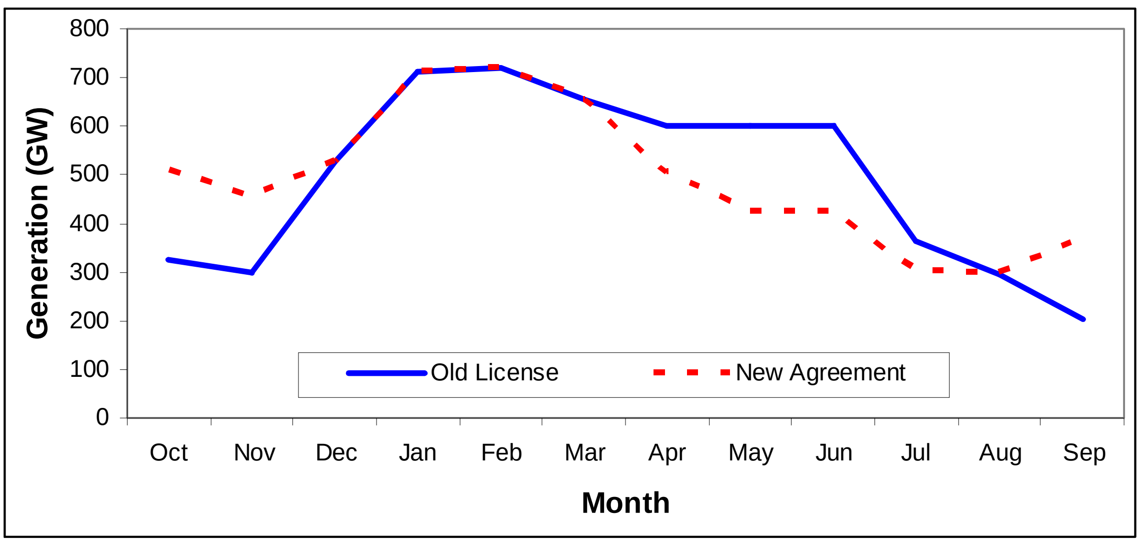

Figure 39. Monthly hydropower generation under climate change based on the old license (no-cooperation) and the new agreement (cooperation).

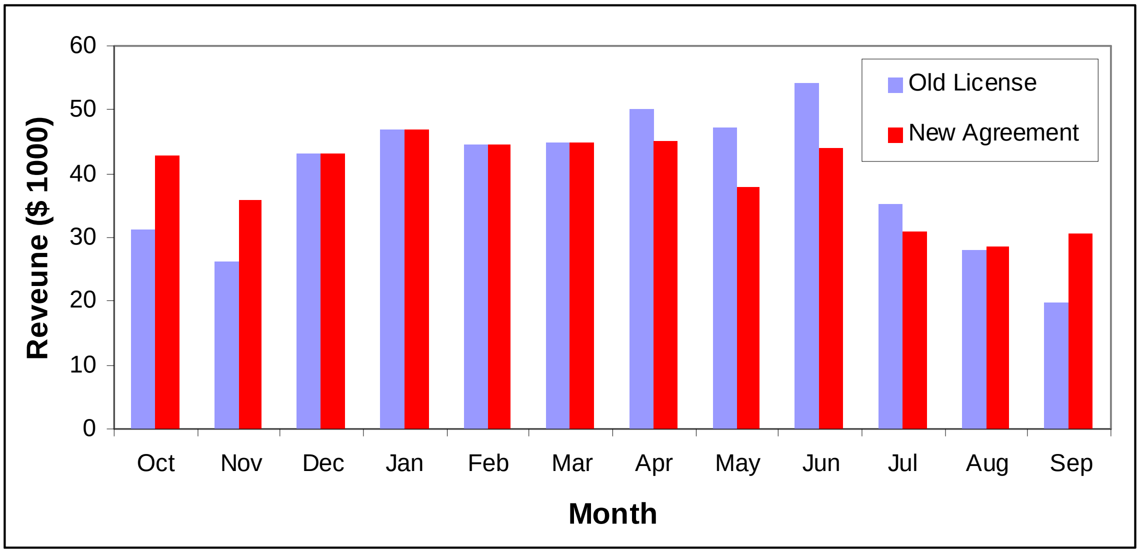

Figure 40. Monthly hydropower revenue for climate change based on the old license (no-cooperation) and the new agreement (cooperation).

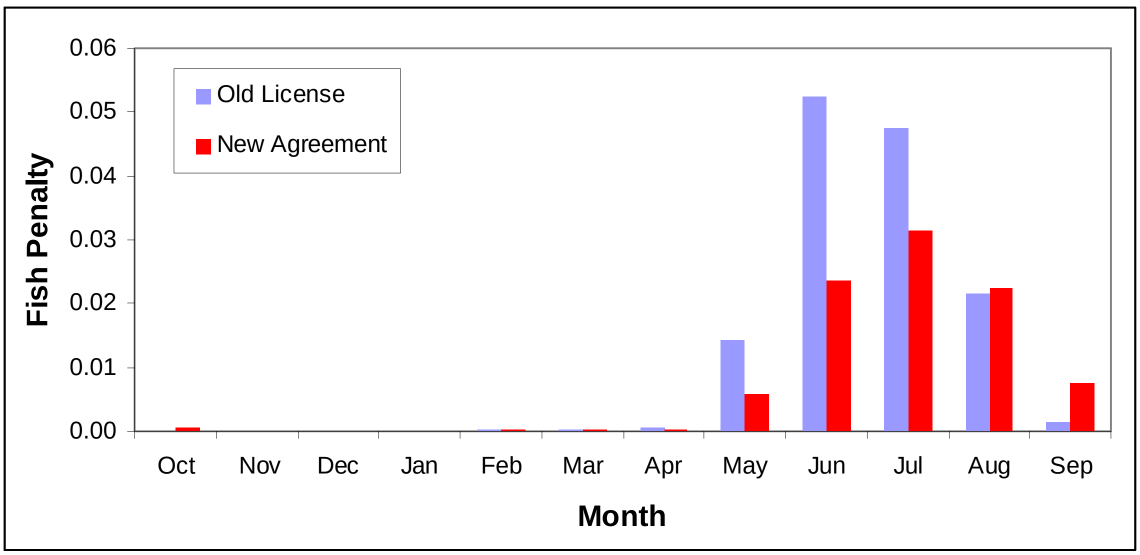

Figure 41. Monthly fish penalties with climate change based on the old license (no-cooperation) and the new agreement (cooperation).

Adaptive FERC License

Climate change may be an incentive to cooperation when the uncertainty about its existence is minimal and its effects on the project are apparent. Therefore, the projects which are currently in the relicensing process might disregard hydrological and ecological effects of climate change due to the lack of reliable information about the climate. Climate change is expected to enter FERC negotiations over the next decades when its impacts are more known and the parties already feel its effects on the system. In the short run, interests pay more attention to their existing benefits and limit their negotiations to current issues, ignoring long-term conditional changes of the system. The terms and conditions in a FERC license will be valid for the duration of the license (25 to 30 years) as well as the next relicensing negotiations period (sometimes up to 50 years). These terms and requirements limit the flexibility of the system to respond to changing conditions, including climate change. Therefore, a framework is suggested for addressing this problem while protecting the rights and basic gains of each party involved in a FERC license.

Although short term licenses may increase the chance of responding to changing conditions and improvement of management based on the new information about the system, the transactions costs and risks of negotiations and the relicensing process can make this solution inefficient. So, assuming the length of the FERC license and the relicensing process does not change, parties might be allowed to amend the terms of the license at intervals during the license period. At the beginning of each interval, parties have two choices. They can either cooperate for changing the license for a limited time to increase gains to all parties, or they can chose to not cooperate and retain the existing license terms. At each interval, parties can use the latest information and calculated gains while bargaining. Cooperation becomes possible when a win-win situation exists and all parties can benefit from the changed terms. The suggested method can increase the flexibility of the system to respond to different changes (e.g. ecological, hydrological, etc.).

In case of the Aab-Band project, let us assume a new license will be issued in 2012, and in the relicensing process climate change is not an initial concern to the parties. This license will be valid until 2042. If in two decades, hydrology changes substantially, the existing terms and conditions may prove infeasible or inferior solution for both parties. If the parties are allowed to amend the license cooperatively, the terms and conditions of the license can be changed slightly when both parties agree that they will gain more under the revised terms. The new terms can be valid for a set time until more information is available and the ecological response is known better. After a set period (say 5 years), the basic terms of the license become valid and the revised terms become invalid. Again, parties can bargain to increase their gain cooperatively for another limited period.

The revision of a license's terms might be done every few years without FERC's involvement (no cost to FERC), to improve the adaptability of the system to changing conditions (most importantly climate change). What makes an adaptive FERC license feasible (in game theoretic terms) is the "no loss factor". No parties can lose from the amendments, as if one party prefers the existing license terms, the license is not changed.

Conclusions

The study suggested the strategic loss concept and revisions to Nash and Nash-Harsanyi bargaining solutions for application to linked games. Based on the Nash bargaining solution for linked games, it was explored why in practice FERC relicensing may take longer than expected. A FERC relicensing bargaining model was developed. This model can support negotiations in stage 3 of the FERC licensing process. The developed model can provide insights into FERC relicensing, explain why parties to a FERC license may refuse to cooperate to complete a relicensing process; and find conditions under which cooperation and speeding the relicensing process becomes possible.

The cases discussed in this paper are just numerical examples of theory with many simplifications and assumptions. In practice, estimating the environmental and ecological benefits is controversial and the functions presented here may not be realistic. During the negotiations, the parties can be asked to provide data and functions for utility estimations. Also, in practice, negotiations involve more than two interests, so the modified Nash-Harsanyi brgaining solution, suggested here, should be applied instead of the Nash bargaining solution. This makes the optimization problem more complicated, increasing the computational effort.

Climate change is not expected to enter the FERC negotiations as a major concern at present. However, over time it may provide incentives for cooperation among the parties to FERC relicensing. The fixed terms and conditions of the FERC licenses limit the flexibility of operations to respond to different changes in the systems' conditions. As the effects of climate change are not largely known, an adaptive FERC license is suggested.

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Chapter 5 –Conclusions

This dissertation studied the effects of climate change on California's high-elevation hydropower system. This chapter summarizes the main contributions of this research and highlights its major findings. Then the limitations of this research are discussed and related future research areas are suggested.

Modeling High-Elevation Hydropower in California

The second chapter explored an approach for studying extensive multi-facility high-head hydropower systems with minimal available information and efficient computation. The No-Spill Method (NSM) was suggested for estimating the energy storage capacities available to each power plant using only recorded energy production data and average seasonal inflow patterns, without detailed information on volumetric storage capacity, inflow, or geometric configuration. Then an energy-unit based model (Energy-Based Hydropower Optimization Model or EBHOM) for single-purpose hydropower generation systems was developed. This innovative model requires little development effort for low-resolution modeling of large high-elevation hydropower systems. EBHOM used an inventive price-frequency method of better representing hourly energy prices in models with larger time steps. The cyclic storage formulation incorporated in EBHOM decreases calculation time and cost substantially. EBHOM was applied to represent 137 high-elevation (high-head) units in California. Although the developed method required some simplifying assumptions, EBHOM was found reliable when tested against an existing hydropower optimization model in a collaborative-comparative study of climate change effects on hydropower generation of Sacramento Municipal Utility District's (SMUD) hydropower facilities in California.

EBHOM is a simple tool for developing a good representation of an extensive system with little time or resources for policy and adaptation studies for various purposes. This model was suggested to 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 preliminary seasonal energy forecast and scheduling studies.

Climate Warming Effects on the High-elevation System

In absence of detailed information about the available energy storage capacity at high-elevation in California, the simple low-resolution approach, suggested in the second chapter, was applied in the third chapter for estimating the adaptability of California's high-elevation hydropower generation to climate warming.

With climate warming, California loses snowpack, but considerable energy storage and generation capacity remain available to provide some flexibility in operations with climate change. Most additional runoff in winter months from climate warming can be accommodated by the available storage capacity at high-elevation sites for average years. Energy spills increase with Wet and Warming-Only climate scenarios. 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. Under the Dry scenario with 20 percent less runoff, revenues decrease by less than 14 percent. Limited capacities cannot take full advantage of increased energy runoff under the Wet scenario, with 10 percent more runoff, but only 2 percent more revenues. Under the Warming-Only climate change, with no change in annual runoff volume, revenues decrease by 2 percent.

FERC Relicensing and Climate Change

In this chapter the strategic loss concept and revisions to Nash and Nash-Harsanyi bargaining solutions for the application to linked games were suggested. Then, it was explored why in practice FERC relicensing process may take longer than expected. A FERC relicensing bargaining model was developed to provide insights for negotiations in stage 3 of the FERC relicensing process. This model can provide insights to FERC relicensing, explain why parties to a FERC license may refuse to cooperate to finalize the relicensing process; and find conditions under which cooperation becomes possible or impossible.

Potential effects of climate change on the FERC relicensing negotiations were explored. Climate change would not be expected to enter the FERC negotiations as a major concern at present. However, over time it might provide incentives for cooperation or conflict among the parties to FERC relicensing. The fixed terms and conditions of the FERC licenses limit the flexibility of operations to respond to different changes in the systems' conditions. An adaptive FERC license is recommended which in face of uncertainty about future climatic conditions can increase the gain of all parties.

Limitations and Future Direction

Development of EBHOM required many simplifications. Nevertheless, EBHOM can provide useful insights into the future of high-elevation hydropower systems in California. Future research should address weaknesses of EBHOM to improve its predictive reliability. The No-Spill Method (NSM) used in the second chapter for estimating energy storage capacities should be applied to systems where there is little or no spill in many years and little over-year storage. The NSM tends to under-estimate storage capacities and therefore underestimates the adaptability of the hydropower system to hydrologic and economic changes. More detailed studies could improve estimates of energy storage capacities. EBHOM was formulated without considering environmental flows. Environmental constraints can 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 may increase with time. Environmental constraints should be incorporated EBHOM in the future. This can be done by defining minimum releases or changing 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. Future research may formulate EBHOM as a stochastic model with less ability to predict inflows or hydropower prices.

Study of climate warming effects on the high-elevation system in California (Chapter 3) required some simplifying assumptions, including the low-variability of hydrologic conditions, absence of environmental constrains, and unchanged hydropower demands and prices under climate change. It is expected that future studies of climate change effects on high-elevation generation in California 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.

The examples discussed in the fourth chapter, examining FERC relicensing using game theory, were numerical examples with many simplifications and assumptions. In practice, estimating the environmental and ecological benefits is controversial and simple functions may not be representative of real situations. Also, more than two parties are often involved, making the problem more complex and difficult. In the future, the suggested method and model might be applied to real FERC relicensing cases. Future research on FERC relicensing negotiations may address the concept of adaptive FERC licenses suggested in this chapter.

Major Findings and Contributions

- Studying large complex systems is possible with simple creative models. While detailed models of complex systems will always require detailed representation, low-resolution models of complex systems can provide some insights with much less effort. Modeling of hydropower reservoir systems in terms of energy units, rather than conventional volumetric units of water, provides some practical advantages for some cases.

- Loss of snowpack in California due to climate warming has inconvenient effects on hydropower, but is generally not catastrophic, in terms of hydropower revenues. Climatic changes which increase annual runoff provide less than proportionate increases in generation and revenues, as spills occur more frequently and with larger magnitudes and the additional generation tend to occur in periods with lower energy prices. Climate changes with reduced annual runoff produce proportionate reductions in energy generation and less then proportionate reductions in revenues, as spills are reduced storage is used to retain generation in periods with the highest energy prices.

- Cooperative game theory solution methods are applicable to FERC relicensing negotiations for finding if parties may not be willing to cooperate. Cooperation among the parties may be feasible when they are willing to lose in some sub-games to gain more in the larger game. Climate change may provide an incentive for cooperation and speeding up the FERC relicensing bargaining in the future.

However, immediate consideration of the importance of climate change effects on hydropower operations during the current FERC bargaining cases is less likely. The fixed terms and conditions of the FERC licenses reduce the flexibility of operations under changing conditions such as climatic changes. Therefore, adaptive FERC licenses may be adopted to facilitate adaptation to changing conditions.