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Climate change impacts on high-elevation hydroelectricity in California

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SUMMARY

While only about 30% of California's usable water storage capacity lies at higher elevations, high-elevation (above 300 m) hydropower units generate, on average, 74% of California's in-state hydroelectricity. In general, high-elevation plants have small man-made reservoirs and rely mainly on snowpack. Their low built-in storage capacity is a concern with regard to climate warming. Snowmelt is expected to shift to earlier in the year, and the system may not be able to store sufficient water for release in high-demand periods. Previous studies have explored the climate warming effects on California's high-elevation hydropower by focusing on the supply side (exploring the effects of hydrological changes on generation and revenues) ignoring the warming effects on hydroelectricity demand and pricing. This study extends the previous work by simultaneous consideration of climate change effects on high-elevation hydropower supply and pricing in California. The California's Energy-Based Hydropower Optimization Model (EBHOM 2.0) is applied to evaluate the adaptability of California's high-elevation hydropower system to climate warming, considering the warming effects on hydroelectricity supply and pricing. The model's results relative to energy generation, energy spills, reservoir energy storage, and average shadow prices of energy generation and storage capacity expansion are examined and discussed. These results are compared with previous studies to emphasize the need to consider climate change effects on hydroelectricity demand and pricing when exploring the effects of climate change on hydropower operations.

1. Introduction

Hydropower facilities in California generated on average 37,000 gigawatt hours (MWh), or 15%, of the annual in-state electricity generation between 1983 and 2001; ranging annually between 9% and 30%, depending on hydrological conditions (McKinney, 2003). Hydroelectricity's very low cost, near-zero emissions, and load-following capacity are some of the reasons for its great popularity (McKinney, 2003; Pew Center on Global Climate Change, 2009). The State of California has the second largest hydropower system in the United States with a total hydroelectric capacity over 14 gigawatts (GW), representing 25% of California's electricity generation capacity (McKinney, 2003). California also relies on hydroelectricity imports from the Pacific Northwest, including Canada and the states of Oregon and Washington (Aspen Environmental Group and M. Cubed, 2005).

In-state hydropower is generated by four types of hydropower systems: high-head, low-storage hydropower plants; low-head multipurpose dams; pumped-storage plants; and run-of-the-river units (Pew Center on Global Climate Change, 2009). While only about 30% of the state's usable water storage capacity is at higher elevations, high-elevation (above 300 m) hydropower units generate, on average, 74% of California's in-state hydroelectricity (Madani, 2010). Madani and Lund (2009) have identified 156 high-elevation (above 300 m) hydropower plants, most of them located in Northern California. Hydroelectric generation is generally their only purpose, and only small amounts of water are necessary to produce substantial quantities of electricity due to their vertical drops of hundreds of meters (Pew Center on Global Climate Change, 2009). They have been designed to take advantage of the snowpack acting as a natural reservoir so that their human-made reservoir is usually small. Their limited storage capacity may make them sensitive to snowpack volume and runoff timing variations (Madani and Lund, 2010).

Climate across the California region can be very different, due to the great differences in altitude and in latitude of the state. According to Kauffman (2003), five major climate types can be observed in close proximity in California; namely Desert, Cool Interior, Highland, Steppe, and Mediterranean. Much of California has warm, dry summers and cool, wet winters (Zhu et al., 2005). In terms of electricity demands this corresponds to high demands in summer for cooling and in winter for heating; whereas, the lowest demands

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occur in spring and fall, when neither great heating nor cooling is required. Precipitation is very uneven throughout the year, with around 75% of the annual average 584 milimeters (mm) occurring between November and March (Zhu et al., 2005) and falling as snow in the Sierra Nevada mountain range (Moser et al., 2009). This situation results in spatially uneven runoff, with more than 70% of California's average annual runoff occurring in northern California (Madani and Lund, 2009).

California's twenty-first century hydrology is expected to be altered by climate change and statewide average temperatures raise of 1.5–5 °C: part of the winter precipitation falling as snow will turn to rain; higher temperatures will lead to a shift in timing of the snowmelt peak flow to earlier months; peak flow's intensity will be reduced; and winter runoff is increased (California Climate Change Center, 2006; Cayan et al., 2008, 2009; Moser et al., 2009; Mirchi et al., 2013). Hydrological changes and variations in the annual runoff pattern create a big concern for California's hydropower system, which may face water shortages in summer when the demand is the highest (Medellin et al., 2006; Moser et al., 2009; Madani and Lund, 2010; Blasing et al., 2013). These changes can significantly alter California's hydroelectricity generation, depending on the system's storage and generation capacities as well as their spatial distribution.

The expected changes should be less problematic for low-elevation (below 300 m) multipurpose hydropower systems benefitting from large human-made reservoirs, than it is for high-elevation units with small human-made reservoirs. Studies of low-elevation multi-purpose reservoirs in California show that the low-elevation hydropower system is not vulnerable to flow timing changes due to warming (Tanaka et al., 2006; Medellín-Azuara et al., 2008; Connell-Buck et al., 2011). This is indeed because of the large storage capacity of this system which provides flexibility in operations. Yet this system is directly affected by changes in flow magnitudes under climate change which might result in lower or higher levels of hydroelectricity production with dry and wet climate warming, respectively. Relying mainly on natural snowpack reserves, high-elevation hydropower systems have a limited flexibility in operation. If their storage capacity cannot accommodate hydrological changes, these high-elevation hydropower systems may be vulnerable to climate change (Madani and Lund, 2010).

Most studies assessing the impacts of climate change on hydropower generation in California have focused on large-scale, low-elevation systems (e.g., Tanaka et al., 2006; Medellín-Azuara et al., 2008) or on a few individual high-elevation hydropower units (e.g., Vicuña et al., 2008, 2011; Madani et al., 2008). High-elevation systems are nonetheless generating 74% of California's in-state hydroelectricity on average, which has prompted recent research on the impacts of climate change on high-elevation hydropower systems (e.g., Madani and Lund, 2007, 2010; Duffy et al., 2009; Madani, 2009). These studies suggested that the current storage and generation capacities enable the system to adapt to climate warming to some extent. In case of dry warming, lower hydropower generation is expected. Nevertheless, the revenue losses in percentage are less than the generation losses due to price variability and the non-linear relationship between hydroelectricity generation and pricing. In case of wet warming, the system cannot fully take advantage of increased flows due to its limited storage and generation capacities. While generation is increased to some extent, the revenues do not increase significantly as increased generation mostly occurs in months with average lower hydropower prices.

Beside its effect on power supply, climate change is expected to affect power demand and pricing. This is because of the temperature changes which can increase the need for cooling in warmer months of the year and decrease the need for heating in colder months. So, some researchers have focused on climate change impacts and energy demand in California (Franco and Sanstad, 2006; Miller et al., 2008; Aroonruengsawat and Auffhammer, 2009; Guégan et al., 2012a). These studies suggest that in general, climate change will result in increased demand, peak load, and average pricing in California. Based on these studies, California is expected to face electricity supply deficit in peak electricity demand periods and with extreme heat, which is expected to occur more frequently with climate change.

Rising energy demand, coupled with reduced hydroelectricity generation, could lead to a substantial impact on the hydropower operations. Therefore, a comprehensive analysis of climate change on hydropower operations, that considers climate change on supply and demand/price side simultaneously is required in order to evaluate the adaptability of California's hydropower system to climate change. Nevertheless, previous research on the climate change effects on hydropower systems operations and adaptability have examined climate change effects on hydropower supply and demand/price independently, leaving a gap in our understanding of the implications of climate change for hydropower operations in California. To bridge the gap, this paper examines the impacts of climate warming on California's hydropower system, considering simultaneously the impact of climate change on the hydroelectricity supply and pricing. The study focuses on high-elevation single-purpose snowpack-dependant hydropower system (including plants above 300 m) which is the major in-state hydroelectricity producer and is expected to be more vulnerable to climate warming and snowpack losses due to its limited storage capacity. The low-elevation hydropower system which provides one quarter of in-state hydropower supply in California is not the focus of this study as hydroelectricity generation is an ancillary benefit of the system, composed of large multi-purpose reservoirs.

2. Method

California's Energy-Based Hydropower Optimization Model (EBHOM) (Madani and Lund, 2009) is used in this study in order to evaluate the adaptability of California's high-elevation hydropower system to climate change. EBHOM is a monthly-step non-linear hydropower revenue optimization model that finds optimal hydropower operations for 137 high-elevation hydropower plants throughout California. Assuming that hydropower operation costs are fixed at a monthly scale, EBHOM maximizes revenue as a surrogate for net revenue (Madani, 2009). EBHOM performs all storage, release, and flow calculations in energy units. It provides a big picture of the system and is a more convenient alternative to conventional volume-based optimization models that usually require detailed information such as streamflows and, storage operating capacities at each individual plant of the system (Madani et al., 2008). EBHOM's reliability has been tested against the traditional volume-based hydropower optimization model developed by Vicuña et al. (2008) on the Upper American River system in a collaborative study by UC Davis and UC Berkeley (Madani et al., 2008). Both models predicted the same changes in generation and revenue with respect to the historical case. Despite the fact that EBHOM is very simplified compared to traditional optimization models, it provides a reliable picture of a complex large-scale hydropower system.

Fig. 1 shows a flowchart of the EBHOM's modeling procedure. The input data required to run EBHOM are: runoff data and frequency of hourly electricity prices for each month of the year. EBHOM has the basic information (i.e., elevation and generation capacity) of 137 high-elevation hydropower plants in California. To estimate the available energy storage capacity at each power plant, EBHOM uses the No Spill Method (NSM) (Madani and Lund, 2009), which is applicable when: plants are operated for net

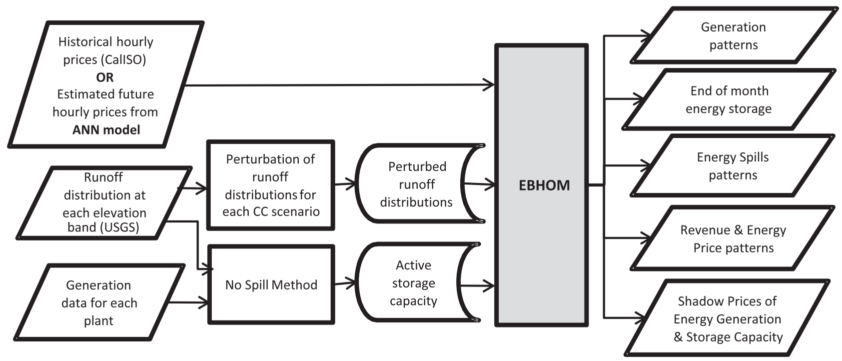

Fig. 1. Flowchart of EBHOM's modeling procedure.

revenue maximization, storage volumes do not significantly affect the turbine/energy head, and there is no over-year storage. These conditions are filled by California's high-elevation hydropower system.

Since in California's electricity market prices fluctuate on an hourly basis and marginal revenues of generation decrease with increased hours of generation, fixed pricing methods fail to reflect the reality of the market. While capturing the fluctuating nature of the pricing in the hydropower market is possible through developing hourly-based hydropower operations models, running such models can be cumbersome and time-consuming. EBHOM uses an innovative method for representing hourly energy prices in a monthly-step model, minimizing the computational effort significantly. Energy prices are derived from the distribution of hourly real-time prices in each month. This allows for capturing the hourly variability in energy prices—on a monthly basis—of the overall energy market that is responding mostly to on-peak and off-peak variability in energy demands. Price information is given to EBHOM as revenue curves. Each monthly revenue curve is the integration over the hourly price frequency curve for that month. A given monthly revenue curve helps estimating the amount of revenue that each power plant can gain based on the turbine capacity used during that month. Average monthly energy price at each power plant is a function of the percent of the time that turbines are in operation, assuming that they operate in hours when the energy market offers higher prices (Madani and Lund, 2009). Revenue curves suggest that marginal revenue of generation decreases by increasing monthly production. Therefore, generating in at any time during a high-price summer month is not necessarily better than generating in a low-price spring month, as generating off-peak in a high-price month might result in less revenue than generating on-peak in a low-price month. Different levels of turbine capacity can be used in different months by different power plants to take advantage of changes in hourly pricing throughout each month and over the year because of changes in demand during a day (off-peak and on-peak) and during the year (hot months, cold months, and average temperature months). Fig. 2 shows sample monthly revenue curves under different climate scenarios. EBHOM piecewise linearizes the non-linear revenue curves into five segments to solve the optimization problem through linear programming. See Madani and Lund (2009) for details on EBHOM's mathematical formulation.

The original EBHOM (EBHOM 1.0), used in earlier evaluations of climate change effects on California's high-elevation hydropower system, was only using historical pricing (2005–2008), ignoring the effects of climate warming on energy demand and pricing. However, given the necessity of considering the effects of climate change on hydroelectricity pricing in energy planning and policy making, this model was improved later on by Guégan et al. (2012a). The revised model (EBHOM 2.0) includes an ANN-based (Artificial Neural Network) price estimation module, that estimates the price distribution changes under different climate change scenarios. Reliable price forecasting is not an easy task, as price of electricity is a nonlinear, time-variant, and volatile signal, owning multiple periodicity, high-frequency components, and significant outliers (especially in periods of high demand) due to unexpected events in the electricity markets (Amjady and Hemmati, 2006). Yet, ANN models have a good ability to estimate normal electricity prices (Zhao et al., 2007) as ANNs provide an appealing solution for relating nonlinear input and output variables in complex systems (ASCE, 2000; Dawson and Wilby, 2001) even with little prior physical knowledge about the systems (Zhang et al., 1998). EBHOM 2.0's long-term price forecast ANN module estimates hydroelectricity prices based on the estimated relationship between temperature, electricity demand, time of year (e.g. season, month, day of the week, and hour), and electricity price as illustrated in Guégan et al. (2012a). This makes EBHOM a reliable planning tool to assess the adaptability of California's high-elevation hydropower system to climate change with simultaneous consideration of climate warming effects on hydropower supply and pricing.

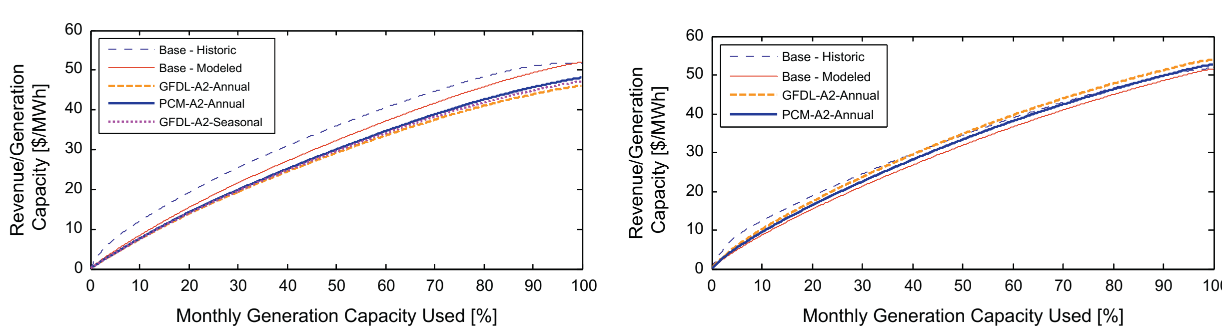

Fig. 2. Monthly revenue curves obtained from ANN1 for January (left) and October (right) for different climate warming scenarios.

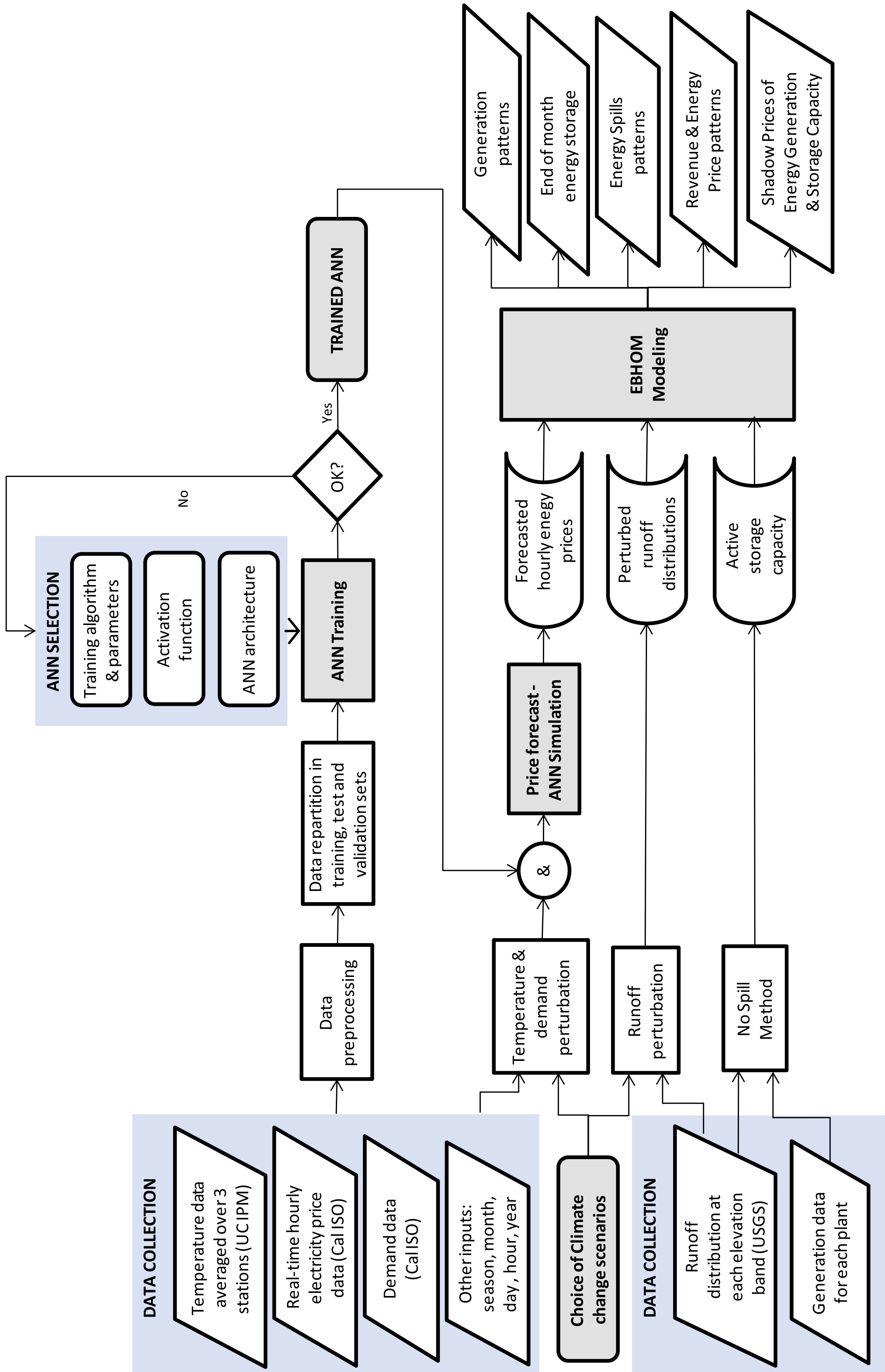

Fig. 3. Flowchart of the study method.

Table 1
Scenarios defined to run EBHOM, including four climate scenarios coupled with three price models.

Scenario acronym	CC scenario	Price model
Base	Base Case	None: Historical prices
Dry	GFDL-A2-Annual	
Wet	PCM-A2-Annual	
Base ANN1	Base Case	ANN1
Dry ANN1	GFDL-A2-Annual	
Dry-Seas ANN1	GFDL-A2-Seasonal	
Wet ANN1	PCM-A2-Annual	
Base ANN2	Base Case	ANN2
Dry ANN2	GFDL-A2-Annual	
Dry-Seas ANN2	GFDL-A2-Seasonal	
Wet ANN2	PCM-A2-Annual	

Fig. 3 outlines the different steps involved in simultaneous evaluation of climate change impacts on high-elevation hydropower supply and pricing in California. The study approach is comprised of two major steps: ANN-based hydroelectricity price distribution determination and hydroelectricity operation optimization. The first step was carried out by Guégan et al. (2012a) resulting in different estimation of hydropower price distribution changes under different climate change scenarios. Based on a numerous data breakdown experiments they selected two ANN models, i.e. monthly based ANN model (ANN1) and an annually based ANN model (ANN2), for estimating long-term hydroelectricity price changes under climate change. These models outperformed the other tested ANN models in matching the historical prices. Following training and selection of the two ANN models, long-term hydroelectricity prices were estimated with perturbed input data to account for different climate warming scenarios. Table 1 summarizes the scenarios selected in their study. The numerical parameters associated with these scenarios (summarized in Table 2) are from Cayan et al. (2006) based on the IPCC Fourth Assessment. Also chosen was an additional seasonal dry warming scenario considering a higher temperature increase in summer and a lower temperature increase in winter, respectively, than in the rest of the year. The outputs of the ANNs were estimated hourly price distributions for each climate change scenario. Fig. 2 shows example revenue curves generated by ANN1 for two different months of the year based on historical prices and changed price distributions under climate change. The second step of the study approach involves running the EBHOM's optimization engine for determining optimal operation policies under different climate change and hydroelectricity price scenario combinations (Table 1).

3. Results

EBHOM's outputs are optimized monthly energy generation, revenue and end-of-month storage data for the statewide high-elevation hydropower system, considering climate change effects on supply and pricing. Modeling results based on 1985–1998 hydrologic conditions and 2005–2008 price dataset [real-time hourly hydroelectric prices from the California ISO Open Access Same-time Information System (OASIS) website (California ISO, 2010)] are presented here. Details about the historical price and temperature data selection and filtering can be found in Guégan et al. (2012a,b).

Table 3 indicates how annual energy generation, energy spill (the equivalent energy value of the water that cannot be stored nor sent through turbines because of limited capacities), and energy revenue change relative to Base case (historical hydrology and pricing) for different climate scenarios and price distributions. For each climate warming scenario (Dry, Wet, or Dry-Seasonal), the average annual generation and energy spills are the same no matter what the price representation is. Energy generation, energy spills, and revenues increase under the Wet scenario but decrease under the Dry scenario relative to the Base case when climate change effects on hydroelectricity pricing are ignored. In this case, increase in revenues under the Wet scenario is only 2% although average generation increase is nearly 6%. Energy spills increase drastically under the Wet scenario, with eight times more spills than under Base case. This occurs due to the limited storage capacity of the system which makes it unable to take a full advantage of the increased water flows. On the other hand, under the Dry scenario, average generation decreases by 20% but revenues only decrease by 14% relative to Base case when climate change effects on hydropower pricing are ignored. The system adapts to the new climatic conditions to maximize revenues and minimize the economic losses from climate change. Generally, when warming effects on pricing are considered, annual revenues decrease relative

Table 2
Climate change scenarios for California (Cayan et al., 2006; Guégan et al., 2012a).

Scenario Name	GCM	SRES	Far-term period (2070–2099) temperature change (°C)[a]		
			Winter (DJF)	Summer (JJA)	Spring (MAM) and Fall (SON)
GFDL-A2-Annual	GFDL	A2	+8.0	+8.0	+8.0
PCM-A2-Annual	PCM	A2	+4.6	+4.6	+4.6
GFDL-A2-Seasonal	GFDL	A2	+6.0	+10.5	+8.0

[a] The temperature change in spring and fall was assumed to be equal to the average annual temperature change.

Table 3
EBHOM's results (average of results over 1985–1998 period) for different climate warming scenarios, considering simultaneously the warming effects on hydropower supply and pricing (ANN1: monthly based ANN model; ANN2: annually based ANN model calibrated on normal prices).

Climate scenario	Base	Dry	Wet	Dry		Dry-Seasonal		Wet	
Price model	Historical			ANN1	ANN2	ANN1	ANN2	ANN1	ANN2
Generation (1000 MWh/year)	22.3	17.9	23.6	17.9		17.9		23.6	
Generation change with respect to the Base case (%)		*−19.8*	*+5.8*	*−19.8*		*−19.8*		*+5.8*	
Spill (MWh/year)	130	96	1112	96		96		1112	
Spill change with respect to the Base case (%)		*−26*	*+756*	*−26*		*−26*		*+756*	
Revenue (million $/year)	1726	1482	1762	1533	1400	1587	1408	1718	1660
Revenue change with respect to the Base case (%)		*−14.1*	*+2.1*	*−11.2*	*−18.9*	*−8.1*	*−18.4*	*−0.5*	*−3.8*

to the Base case for both drier and wetter conditions. This is because increased generation occurs mainly in months with lower average hydroelectricity pricing.

Depending on the ANN model used to estimate prices, there can be significant differences in average revenues received, especially under drier conditions. Under Dry climate, the difference in revenues between models using ANN1 or ANN2 is about $130 million/year, and under Dry-Seasonal climate it reaches $180 million/year. Generally, ANN1 predicts higher annual average revenues than ANN2 under all climates. The Dry scenario estimates more important decreases in revenue than the Dry-Seasonal one.

3.1. Generation changes with climate warming

Fig. 4 shows average monthly energy generation for 1985–1998 for different climate warming scenarios. Results are summed from all of the 137 units modeled. Generally, generation increases between January and April with Wet scenarios due to increased runoff and decreases between April and June with Dry scenarios compared to Base case. When climate warming effects on hydropower pricing are also considered, average monthly generation increases in July and August and decreases from November to February under all scenarios, compared to when those considerations are ignored. Less generation is necessary in winter since less energy is needed for heating, and more generation is necessary in summer to satisfy the high cooling demand. Generation peaks in July or August (depending on the ANN model considered) and in April under Wet scenarios (the generation peak in April under the Wet hydrology is due to the insufficiency of storage capacity to hold the water for hydroelectricity generation in summer). The highest peaks occur in July for ANN2 and reach 2500 MWh/month for Dry ANN2; 2700 MWh/month for Dry-Seasonal ANN2; and 2900 MWh/month for Wet ANN2. Dry-Seasonal scenarios estimate more generation in July and August than Dry scenarios. In the rest of the months, generation is not considerably sensitive to warming effects on energy pricing distribution.

3.2. Reservoir storage changes with climate warming

Fig. 5 shows how average total end-of-month energy storage of the system (in all reservoirs combined) changes with drier and wetter scenarios. Reservoirs start refilling earlier in the year under the Dry scenarios than they do under the Wet scenarios and the Base case. Under the Dry scenarios, the system must take maximal advantage of the water available from late fall to spring, to release it when prices are the highest, i.e. in summer. Between February and June, the system stores more water in its reservoirs when future changes in pricing are considered than when they are ignored. This is valid for both drier and wetter scenarios. Less energy is needed in cold months, so more water is available to be stored until high-demand months. The peak storage occurs in May with all climate change scenarios, one month earlier than in the Base case. From July to December/January, less energy is stored when changes in pricing are considered. On average, the system's total storage capacity is never used. The main difference between the two ANN models is that on average less energy is stored in summer for ANN2 compared to ANN1. There is no significant difference between the Dry and Dry-Seasonal scenarios, except slightly less storage in summer for the latter scenario.

3.3. Energy spills with climate warming

Fig. 6 shows the distribution of total average monthly energy spill for dry and wet climate scenarios when the system is optimized for revenue maximization. This study calculated energy spill as the increased energy spill with respect to the Base case, so zero spills under the Base case is generally expected based on the No Spill Method (NSM) used by EBHOM. However, results show a min-

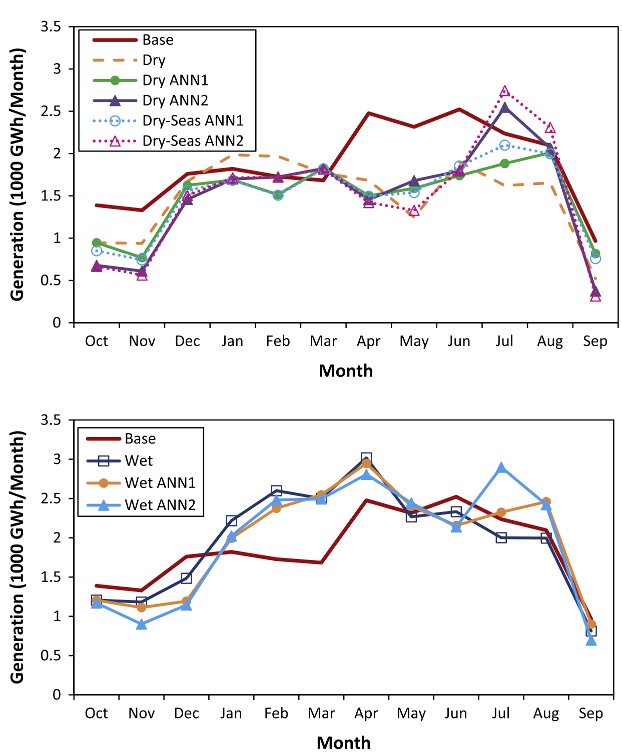

Fig. 4. Average monthly generation (1985–1998) under Dry (top) and Wet (bottom) warming scenarios.

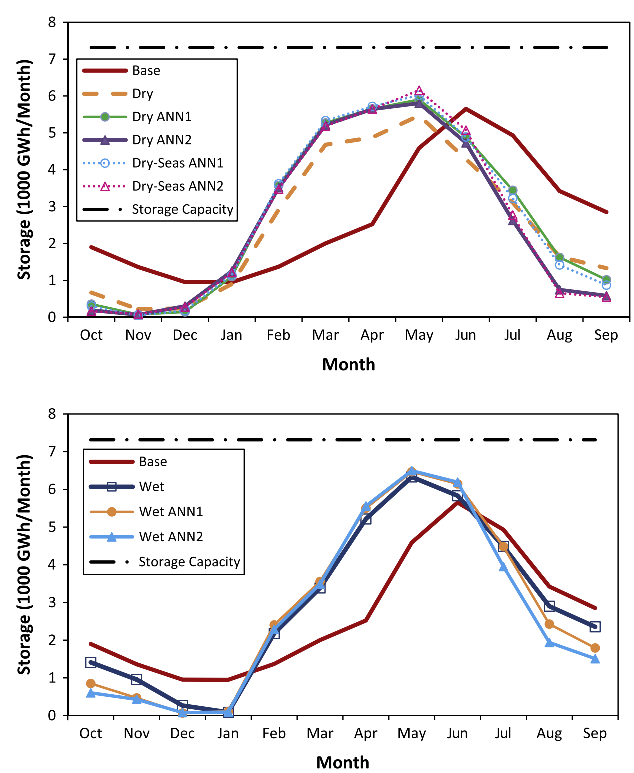

Fig. 5. Average total end-of-month energy storage (1985–1998) under Dry (top) and Wet (bottom) warming scenarios.

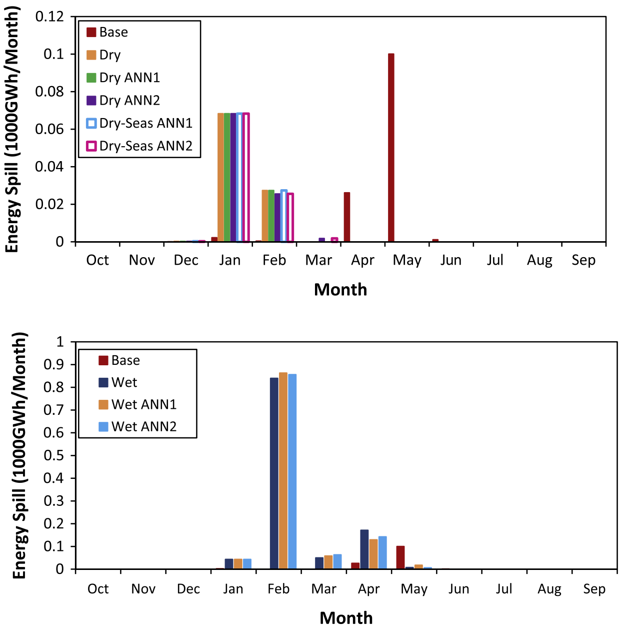

Fig. 6. Average monthly total energy spill (1985–1998) under the Dry (top) and Wet (bottom) warming scenarios.

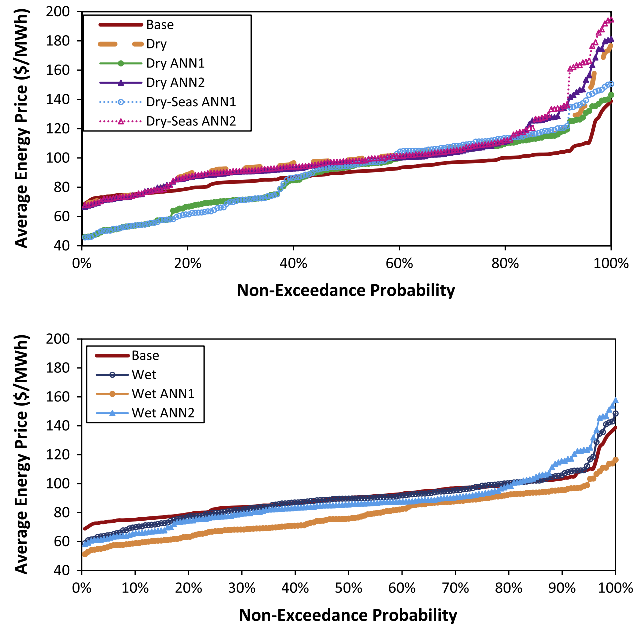

Fig. 7. Frequency of monthly energy prices (1985–1998) under Dry (top) and Wet (bottom) warming scenarios (all months, all years, all units).

imal model error of 130 MWh, corresponding to 0.6% of total generation on average, under the Base case.

Spills occur in the refilling season (December to May) before the high-valued summer season, and reach about 850 MWh in February for the Wet warming scenarios. The annual energy spill profile is not considerably sensitive to warming effects on energy pricing distribution. EBHOM suggests emptying reservoirs in advance since it has perfect foresight (due to its deterministic nature) into the future.

3.4. Revenue and energy price patterns with climate warming

Fig. 7 shows climate warming's effects on the monthly average prices received for generated energy in the 1985–1998 period for dry and wet climate scenarios. Prices received with dry scenarios exceed the monthly average energy prices received under the Base case (85% of the time under Dry ANN2 and Dry-Seasonal ANN2 and 60% of the time under Dry ANN1 and Dry-Seasonal ANN1). The aggregate monthly energy price received with both Dry-Seasonal scenarios exceeds those under their respective Dry scenario. Under Dry scenarios, aggregate monthly energy prices for 1985–1998 are about \$150–\$160/MWh with ANN1; whereas, they are about \$180–\$190/MWh with ANN2. Generally, average prices received with the ANN2 price estimation module exceed prices received with ANN1. Monthly energy prices under Wet ANN1 never exceed prices received under the Base case scenario or other Wet scenarios. Prices received under Wet ANN2 are lower than those estimated under the Base case and Wet scenario 85% of the time, but exceed both of those the rest of the time. Generally dry scenarios increase monthly energy prices relative to the Base case; whereas, Wet scenarios decrease prices.

Fig. 8 shows the effects of climate warming on the frequency of total annual revenues from the system for the 14-year study period (1985–1998). Under dry conditions, annual revenues received are always lower than those under Base case. Although monthly average prices received for generated energy were higher under the Dry scenarios, the increase in average prices received does not compensate for the generation loss with Dry scenarios. For drier climate, considering the simultaneous effects of climate warming on hydropower supply and pricing leads to an increase in annual revenues when the model is based on ANN1, and a decrease when the model is based on ANN2. For wetter conditions, considering the simultaneous effects of warming on hydropower supply and pricing decreases revenues compared to when those effects are ignored. For all climate warming scenarios, ANN1 increases revenues compared to ANN2 as monthly-based models (ANN1) used here are likely to overestimate future prices (Guégan et al., 2012a).

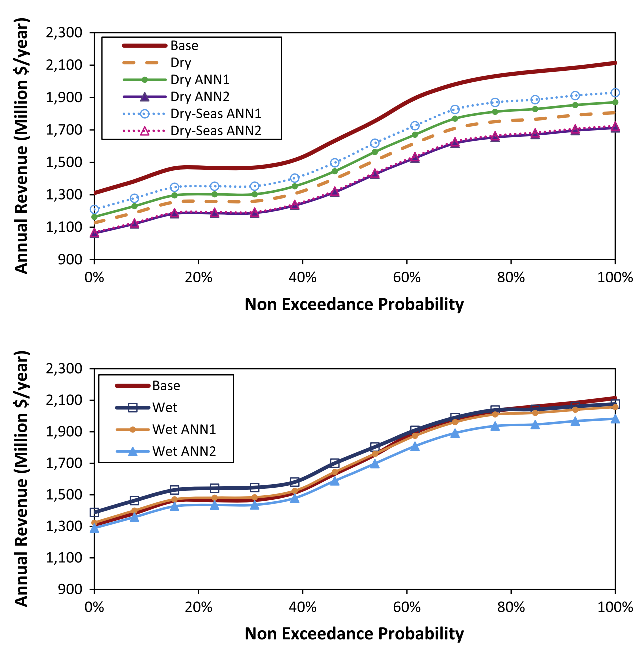

Fig. 8. Frequency of total annual revenue (1985–1998) under Dry (top) and Wet (bottom) warming scenarios.

3.5. Benefits of expanding energy storage and generation capacity with climate warming

In constrained optimization shadow prices of constraints can be calculated. A shadow price or Lagrange multiplier reflects the marginal utility of relaxing a constraint. In other words, shadow price shows the amount of change in the value of the optimal solution obtained by relaxing the constraint by one unit. Shadow prices of energy generation capacity and energy storage capacity are among the major outputs of EBHOM with important policy implications.

Fig. 9 shows, on average, how energy storage capacity expansion changes hydropower generation revenues for dry and wet scenarios over the 14-year study period (results for dry seasonal scenarios are similar to those for the respective dry scenarios). 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. The increase in annual revenues per 1 MWh of energy storage capacity expansion ranges between \$45 and \$81 under dry scenarios and between \$52 and \$58 under wet scenarios. All climate warming scenarios increase the benefits from expanding storage relative to the Base case. Storage capacity expansion reduces spills in the refilling season and furthers release in summer when energy is the most valuable. Overall, benefits of capacity expansion under wet scenarios outweigh benefits under most dry scenarios (except for about 50 plants under Dry ANN1), which was expected since the additional capacity can be more frequently used. Price estimation module ANN1 estimates the greatest revenues in all cases.

Fig. 10 indicates the average shadow price of energy generation capacity (increase in annual revenue per 1 MWh of annual energy generation capacity expansion) for the entire system, for wet and dry scenarios. All scenarios benefit from an increase in generation capacity, reducing spills and allowing more energy to be generated when prices are high. The system's increase in annual revenue per 1 MWh energy storage capacity expansion

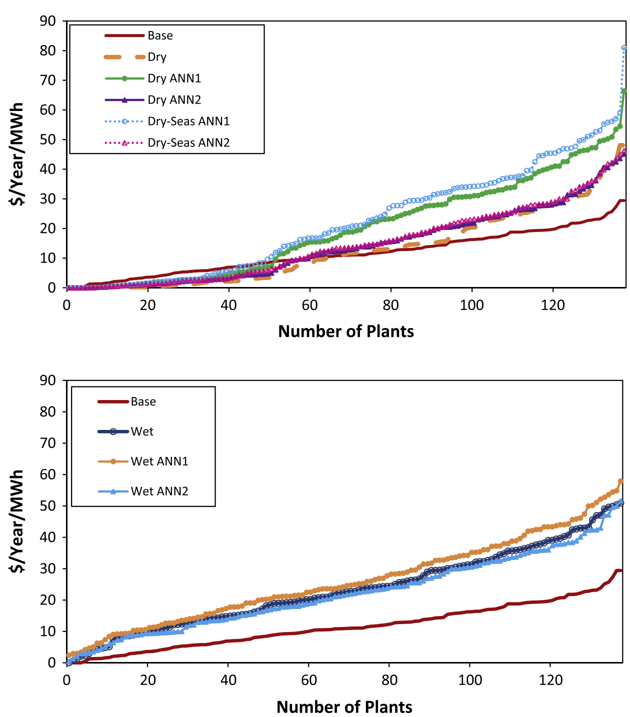

Fig. 9. Average shadow price of energy storage capacity of 137 hydropower units in California in the 1985–1998 period under Dry (top) and Wet (bottom) warming scenarios.

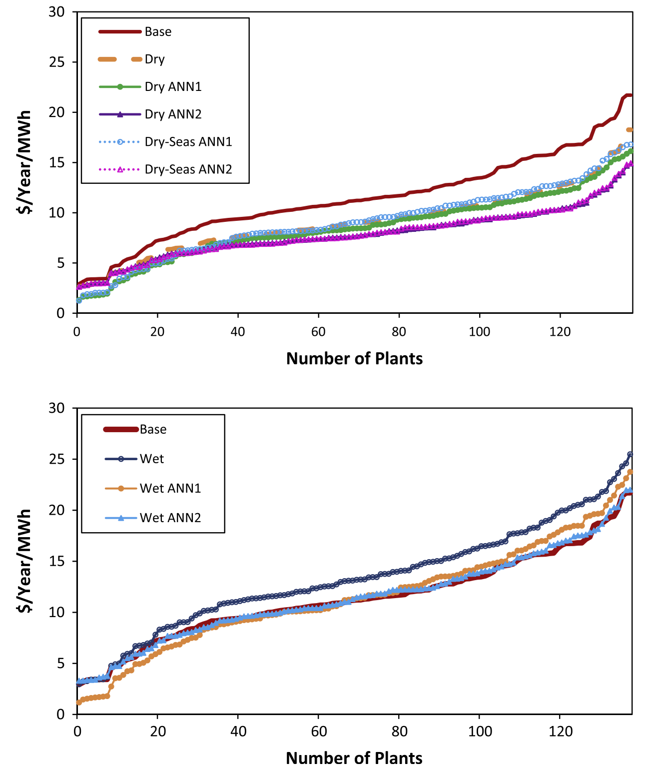

Fig. 10. Average shadow price of energy generation capacity of 137 hydropower units in California in the 1985–1998 period under Dry (top) and Wet (bottom) warming scenarios.

ranges between \$15 and \$18 under dry scenarios and between \$22 and \$25 under wet scenarios. In this case, considering climate warming effects on pricing attenuates the benefits from such an expansion relative to the initial warming scenarios (Dry and Wet). This is exemplified in the wet scenarios where both price estimation modules show decreased revenues for most plants compared to Wet scenario.

Fig. 11 indicates how the marginal benefits of energy storage and generation capacity expansion of power plants vary with the different scenarios (each point is a power plant). It clarifies the relative importance of extra energy generation and storage capacity for each unit. Comparison of the different diagrams in this figure shows how storage capacity generally becomes more valuable than generation capacity under all climate warming as the scatter in the figures expands to the right, considering that expansion costs are the same. Storing water in off-peak months for future release when prices are high is more profitable and facilitates more flexibility in operations. Under dry scenarios, 55–67% of the plants benefit more from storage capacity expansion (resp. 86–89% under wet scenarios). Under conditions, the remaining 40% of the plants (on average) do not spill and would benefit more from installing additional turbines.

Fig. 12 shows the changes of marginal benefits of energy storage and generation capacities relative to the Base case with dry and wet scenarios. Under dry scenarios, marginal benefits of energy generation capacity of all units are lower than the Base case, because water supply availability is the limiting factor. Expanding energy storage capacity under drier conditions is more valuable than it is under the Base case for 55–87% of the units (maximum differences can range between \$28 and \$50). Shifting inflows to high-valued summer months is the most profitable. For wet scenarios, most units benefit both from storage and generation capacity expansion relative to Base case; storage capacity expan-

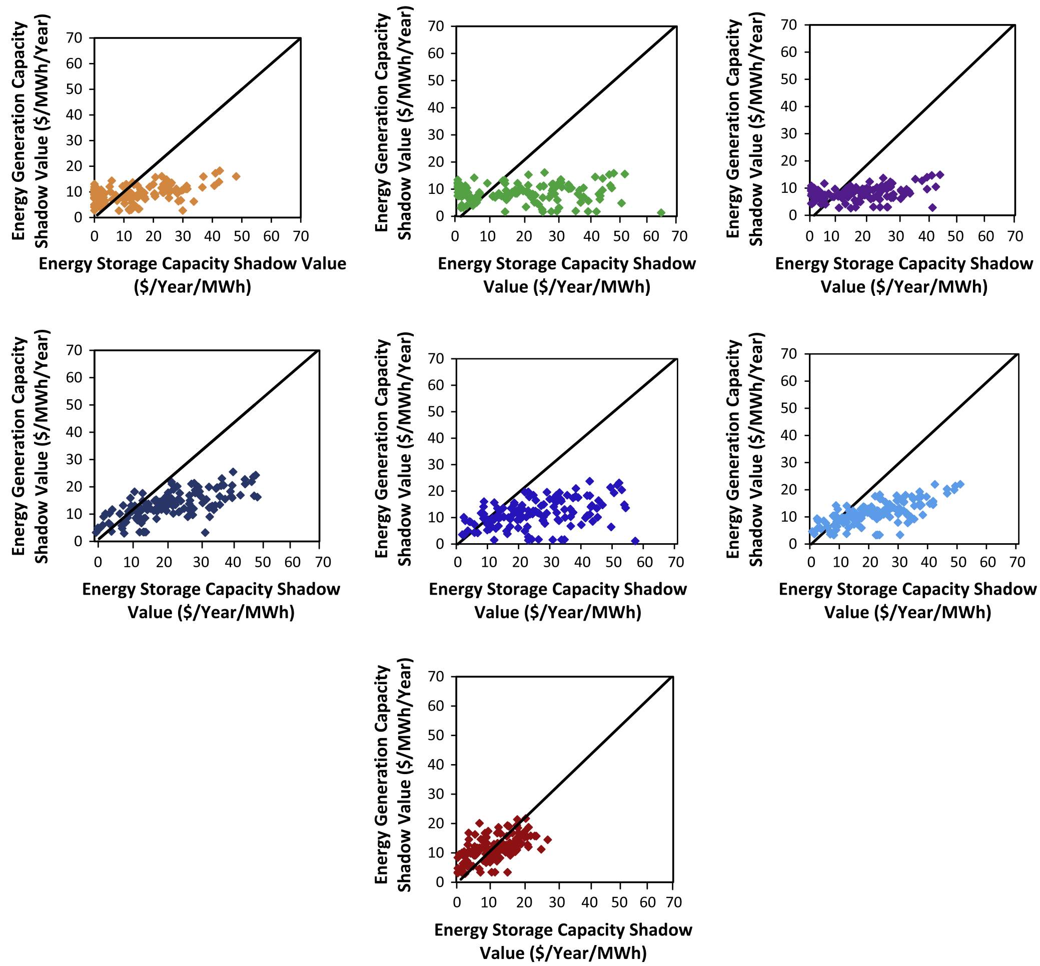

Fig. 11. Average shadow values of energy storage and generation capacity of 137 hydropower units in California in the 1985–1998 period under Dry (top-left = Dry-ANN1 and top-right = Dry-ANN2) and Wet (bottom-left = Wet-ANN1 and bottom-right = Wet-ANN2) warming scenarios.

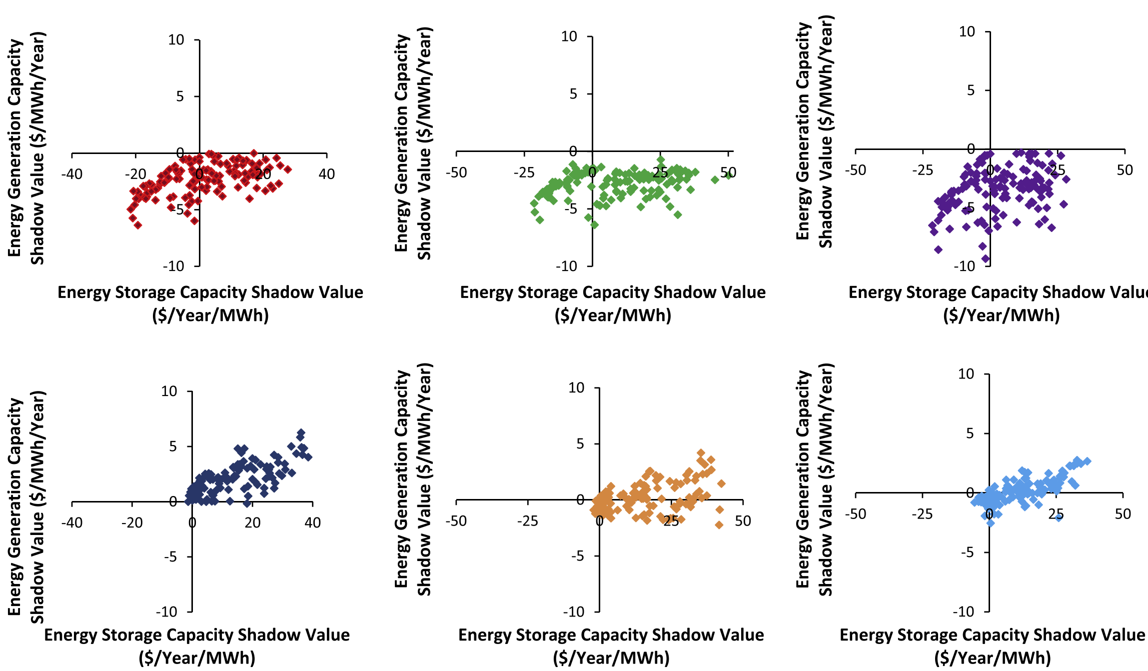

Fig. 12. Average change of energy storage and generation capacity shadow values from the Base Case for Dry (top-left = Dry, top-middle = Dry-ANN1, and top-right = Dry-ANN2) and Wet (bottom-left = Wet, bottom-middle = Wet-ANN1 and bottom-right = Wet-ANN2) warming scenarios (for 137 hydropower units in the 1985–1998 period).

sion outweighing generation capacity expansion for 82–90% of the units (maximum differences range between \$37 and \$42).

3.6. Pure price increase scenarios coupled with climate warming scenarios

EBHOM 2.0's price estimation module can only account for the effects of temperature changes on hourly prices of hydroelectricity. However, California expects to see an increase in electricity prices for various reasons, including demographic trends (size and distribution of the state's population); economic growth (Aroonruengsawat and Auffhammer, 2009); changes in the energy market (demand and pricing of resources such as gas, nuclear, or photovoltaic) (Franco and Sanstad, 2006); and new stringent environmental policies. Two pure price increase scenarios (+30% or +100% by 2100) are defined in this study and coupled to the climate warming scenarios discussed previously. Inspired by the work from Aroonruengsawat and Auffhammer (2009), the first scenario assumes a discrete price increase of 30% by 2020 and remaining at that level until the end of the century. The second scenario is based on the historical trend of average electricity retail prices in California. A linear regression of average retail prices for the period 1960–2005 corresponds to an annual growth rate of around 0.25 cents/KWh. Assuming the same trend through the twenty-first century leads to more than 100% increase in retail prices by 2100 relative to 2005. A 100% price increase by 2100 was set as the most extreme scenario in this study.

Fig. 13 shows the average annual revenues for each price increase scenario (±0%, +30%, and +100% by year 2100) coupled to warming scenarios. EBHOM's price representation is derived from the distribution of hourly prices in each month. The linear increases in prices from our scenarios result in a linear increases in revenues (i.e. a price increase of 100% under a Dry scenario increases average annual revenue by 100% relative to the initial Dry scenario). Revenues are increased by K percent ($K = 30$ or 100) under each price increase scenario, and so are average shadow prices of energy generation expansion and energy capacity expansion. Coupling pure price increase scenarios does not alter energy generation, end-of-month storage and energy spills profiles relative to the initial scenarios. The system is optimized for revenue maximization without a need to adjust operations since the price distribution is not modified. However, energy storage expansion and energy generation expansion become more valuable when price increase scenarios are considered.

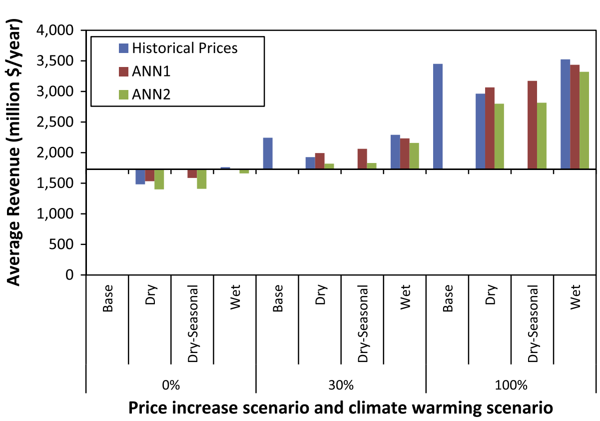

Fig. 13. EBHOM's annual revenue results (average of results over 1985–1998 period) for different climate warming scenarios coupled to price increase scenarios by 0%, 30%, and 100%. scenarios are based on historical prices, or estimated future energy prices from monthly ANN Models (ANN1) or an annual ANN model (ANN2). The horizontal axis crosses the vertical axis at the base case (+0%) average revenue value.

4. Summary and conclusions

The main objective of this study was to evaluate the adaptability of California's high-elevation hydropower system to climate change. In other words, this study wanted to evaluate if the system is capable of keeping the status-quo benefits by modifying operations in response to the changing climatic conditions. The recent version of California's Hydropower Optimization Model—EBHOM 2.0—, which includes an ANN module to estimate climate warming impacts on hydroelectricity pricing, was used as the assessment tool to model 137 hydropower plants across California.

When climate change effects on hydroelectricity pricing were ignored [for detailed results of model runs under different climate change scenarios with no consideration of possible pricing changes, i.e. with historical prices see Guégan et al. (2012b)], modeling results showed that energy generation increased from January to April under the Wet scenario; snowmelt water was plentiful, and the system had limited capacity to store the shift in peak runoff. Average monthly generation also increased under the Dry scenario from January to March, relative to Base case, but decreased in the rest of the months, since less inflow was available. For Dry warming scenarios, the month that the reservoirs refilled shifted to earlier in the year, to capture the shifted snowmelt. The peak end-of month storage was in May for both scenarios; whereas, it was in June under Base case. Under the Wet scenario, energy spills increased by nearly 1000 MWh between January and April compared to the Base case. Energy spills occur when the system cannot store all the incoming runoff or send it through the turbines. Even if average generation increased by nearly 6% under the Wet scenario relative to Base case, average revenues only increased by 2%. Under the Dry scenario, average generation decreased by 20%, but revenues only decreased by 14% relative to Base case, showing that the system is able to adapt, to a certain extent, to changing climate. The system increases annual revenues if either energy storage or energy generation capacity is expanded under the Wet and Dry scenarios, relative to the Base case. Energy storage capacity expansion is more beneficial than generation capacity expansion, although such expansion might not be justifiable due to expansion costs. As expected, benefits of capacity expansion are greater for the Wet scenario, when the additional capacity can be more frequently used.

EBHOM's results, when climate change effects on hydropower supply and pricing and considered simultaneously, suggest that energy generation increases in warm months when demand is high and energy is valuable, and decreases in winter, when less heating is needed and prices are off-peak. This holds true for both climate warming scenarios and both ANN models. Between February and June, end-of-month storage increases under all scenarios relative to results from studies that ignore pricing changes. Less energy is generated in warmer winters; therefore, water is available to be stored until the high-demand season. Energy spills are not much different from EBHOM's results based on historical pricing. Under the Wet scenarios, energy revenues decrease, because average energy price received decrease and average energy revenues are lower than in Base case. Under the Dry scenario, revenues are always lower than Base case, and the monthly-based ANN model suggest more revenues than the annually-based ANN model. The system under the Dry scenarios benefit more from energy storage capacity expansion than when historical prices are considered. The marginal benefits from energy generation expansion under both the Dry and the Wet scenarios that consider the effects of warming on pricing are estimated to decrease relative to results of studies that do not consider those effects.

Expanding the energy storage capacity of California's high-elevation hydropower system seems to be the most beneficial option to adapt to climate change and maximize the increase in revenue, although such expansion might not be justifiable due to considerable expansion costs. The increased benefits might range from \$45 to \$81/year/MWh when changes in pricing are considered, depending on the climate scenario. Future research should conduct a case-by-case study of the benefits gained by each power plant to decide whether storage or generation capacities should be expanded at each unit.

The identified differences between the estimated impacts of climate change on California's high-elevation hydropower system with consideration and without consideration of climate change effects on hydropower demand and pricing have an important policy implication: "Studies that ignore the climate change effects on the demand side of hydropower systems do not provide a reliable picture of the system in the future and the potential effects of climate change effects on hydropower demand and pricing must be considered in future adaptation studies and policy making regarding hydropower."

Finally, it should be noted that the interest of this study was in the "big picture"; so many simplifying assumptions were necessary and should be considered in interpreting the results, especially for advising policymakers. Results from this work give, however, valuable insights on how the system works and how it might adapt to climate change. Extensive discussions of the limitations of EBHOM and its price estimation module have been provided in Madani (2009) and Guégan et al. (2012a). Future studies can provide a more comprehensive picture of hydropower's future in California by addressing some of these limitations.

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