# Assessing climate change impacts on the Iberian power system using a coupled water-power model

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**Abstract** Climate change is expected to have a negative impact on the power system of the Iberian Peninsula; changes in river runoff are expected to reduce hydropower generation, while higher temperatures are expected to increase summer electricity demand, when water resources are already limited. However, these impacts have not yet been evaluated at the peninsular level. We coupled a hydrological model with a power market model to study three impacts of climate change on the current Iberian power system: changes in hydropower production caused by changes in precipitation and temperature, changes in temporal patterns of electricity demand caused by temperature changes, and changes in irrigation water use caused by temperature and precipitation changes. A stochastic dynamic programming approach was used to develop operating rules for the integrated system given hydrological uncertainty. We found that changes in precipitation will reduce runoff, decrease hydropower production (with accompanying increases in thermal generation), and increase irrigation water use, while higher temperatures will shift power demand from winter to summer months. The combined impact of these effects will generally make it more challenging to balance agricultural, power, and environmental objectives in the operation of Iberian reservoirs, though some impacts could be mitigated by better alignment between temporal patterns of irrigation and power demands.

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## 1 Introduction

Water resources systems and power systems are strongly linked; water is needed for many power generation technologies and electricity is required in most stages of water usage. While some aspects of this interdependency were described two decades ago by Gleick (1993), the water-energy nexus has recently gained renewed interest (Hoffman, 2004; DOE, 2006; Olsson, 2012).

Climate change will have an impact on the power system: changes in runoff will affect hydropower generation (Lehner et al., 2005; Schaefli et al., 2007; Vicuna et al., 2008) and cooling water availability for thermal power generation (Koch and Vogele, 2009; CCSP, 2012). Increasing air and surface water temperatures will reduce the generation cycle efficiency of thermal power plants (Forster and Lilliestam, 2010; CCSP, 2012) and rising temperatures will likely decrease winter electricity demand and increase summer electricity demand (Isaac and van Vuuren 2009). Ebinger and Vergara (2011) present a systematic account of several direct and indirect impacts of climate change on energy systems around the world and Mideksa and Kallbekken (2010) present a literature review on the same topic.

A few studies attempt to model the impacts of climate change on the power system. Golombek et al (2012) use an economic equilibrium model to study the individual impact of temperature and precipitation changes on electricity demand, hydropower supply, and thermal power efficiency in Western Europe for the period 2070–2100. They conclude that net effects include a 1 % increase in electricity prices and a 4 % reduction in supply, mostly due to reduced winter demand. SINTEF (2011) uses expected inflows and temperatures along with expected electricity demand and generation technologies to run the EMPS power system model (Wolfgang et al., 2009) for the NordPool countries (Eastern Denmark, Finland, Norway and Sweden). It concludes that by 2050 higher air temperatures will reduce electricity demand while higher inflows will increase hydropower, displacing thermal generation, reducing electricity prices and $CO_2$ emissions in the NordPool, and increasing net energy exports to the rest of Europe. Seljom et al. (2011) reach similar results for the Norwegian system using an energy system model of Norway to represent the energy sector and the EMPS model to simulate hydropower production.

Climate change is expected to have a negative impact on the Iberian Peninsula (IP); the hydropower potential in Spain and Portugal will likely decrease due to reduced runoff (Lehner et al., 2005) while higher temperatures will likely decrease (increase) winter (summer) electricity demand (Giannakopoulos et al., 2009). Even though the two countries have a common power market and share the major river basins on the peninsula, no assessment has been published on the impact of climate change on the power system as a whole.

This study presents a methodology to quantitatively analyze some of the components of the water-energy nexus, and how they can be impacted by climate change. This is achieved by coupling a hydrological and a power system model. Changes in electricity demand caused by air temperature changes are analyzed through the heating and cooling degree day approach; changes in river discharge due to changes in temperature and precipitation patterns are analyzed using a rainfall-runoff model. Hydropower is represented by an equivalent energy reservoir and the reservoir operating rules are developed using an application of stochastic dynamic programming known as the *water value method*. The methodology is demonstrated for the IP, which is highly dependent on hydropower generation and irrigation agriculture.

## 2 Materials and methods

Water resources systems and power systems differ in spatial extent: the natural organizational scale for hydrological systems is the catchment scale, while power systems are most usefully analyzed at the transmission system scale. We chose to test our approach in the IP because: its power system is expected to be negatively impacted by climate change; the two countries share most of the major river basins in the region; and they have a common power market (the MIBEL) with relatively small exchanges with other countries (less than 2 % of total production).

### 2.1 Rainfall-runoff model

The seven major river basins of the IP were divided into three sub-catchments each and a rainfall-runoff model was established for each of the resulting 21 *simulation sub-catchments*. The rainfall-runoff model was implemented in NAM (Nielsen and Hansen, 1973), a lumped conceptual modeling system that consists of water balance equations in four storages representing the land phase of the hydrological cycle: snow storage, surface storage, lower soil zone storage and groundwater storage. The modeling system requires daily precipitation, reference evapotranspiration, and air temperature (if snow is considered) inputs, as well as observed discharge data for calibration.

We used daily precipitation data from Spain02 (Herrera et al., 2012) and PT02 (Belo-Pereira et al., 2011) station-based gridded products (0.2° spatial resolution); mean daily temperature from E-Obs' station-based, 0.22° gridded product (Haylock et al., 2008); and reference evapotranspiration rate computed from temperature data using the approach recommended by Oudin et al.(2005) for lumped rainfall-runoff models. To account for snow accumulation and melt, catchments with elevations above 1,600 m.a.s.l. were subdivided in elevation zones of 200 m each, where snowmelt was determined using a temperature index method (Hock, 2003). The temperature within each elevation zone was adjusted using a dry adiabatic lapse rate of 0.6 °C/100 m, as recommended by Lopez-Moreno et al. (2009) for the Spanish Pyrenees.

The discharge data used for calibration was obtained from the Spanish Center of Hydrographic Studies (CEDEX, 2012) and the Portuguese National Water Institute (SNIRH, 2012). The model was calibrated on daily time steps using NAM's automatic calibration module (Madsen, 2000), which employs a shuffled complex evolution algorithm. It was not possible to calibrate the models using observed discharge data because of distortions to the natural river runoff regime caused by reservoir and irrigation operations. Instead, smaller unregulated *calibration sub-catchments* were used to derive model parameters, which were then applied to the simulation catchments (see Fig. 2 in Online Resource 1). The transfer of model parameters from calibration to simulation catchments was done manually: parameters for each simulation catchment were taken from the calibration catchment with the most similar slope, land use and soil type. The calculated runoff was used to generate energy inflow time series using a reservoir aggregation methodology (see below).

### 2.2 Irrigation demand

Irrigation is the largest consumptive water user in the peninsula and must be included in the hydrological model. We estimated irrigation water use based on Wriedt et al. (2009), who

present $10 \times 10$ km estimates of yearly average irrigation water requirements for the European Union and Switzerland. Annual precipitation estimates (included in the dataset) were added to the irrigation water requirements to obtain total water demand. This was done to calculate water requirements from control and climate change scenario by subtracting the corresponding precipitation estimates. We aggregated the total water demand of each simulation catchment into one irrigation scheme, and distributed the yearly values over the months of the year in proportion to observed monthly requirements in the Ebro Basin (J. Galvan, personal communication, 10 August 2012). Because of lack of data, it was assumed that all catchments had the same temporal irrigation pattern, and that the data for Spain are representative for Portugal.

Despite significant groundwater abstractions in many river basins, irrigation was modeled as a surface water user; it was assumed that groundwater abstractions will eventually result in river discharge reductions. This assumption ignores abstractions from aquifers that are not connected to surface water, and non-sustainable over-abstraction (abstractions that exceed recharge).

Due to the coarse spatial scale of the model, only the consumptive use of irrigation was considered. The portion of the abstractions for leaching of salts and to compensate for application efficiency will return to the system, so *return flows* were ignored. There are other water users, including industry, municipal water supply, and cattle, but only irrigation is considered here because it represents above 75 % of water withdrawals in Spain (MMA, 2007). Ecological flows were not included as users because such data were not available.

2.3 Climate change scenario

River discharge under possible climate change scenarios was calculated by running rainfall-runoff models with climate change input data. Precipitation and temperature time series were generated using the so-called *delta change method*, in which the average monthly change in climate model output between control and future simulation periods is used to scale observed daily precipitation and temperature data (Fowler et al., 2007). The resulting monthly change factors (CFs) are multiplicative for precipitation and additive for temperature.

In order to assess the robustness of the results with respect to the climate change input data, CFs were calculated for three different regional climate models (RCM) from the ENSEMBLES Project (van der Linden and Mitchell, 2012), which uses the A1B emission scenario. The selected RCMs were those that show a high spatial correlation of precipitation regime with the precipitation product Spain02, according to the assessment presented by Herrera et al. (2010). These are: RACMO2 (van Meijgaard et al., 2008), CLM (Jaeger et al., 2008) and REMO (Jacob et al., 2001). The control and future simulation periods were defined as 1961–1990 and 2036–2065, respectively.

The three sets of monthly CFs were applied to observed precipitation and temperature series to generate forcing data for the rainfall-runoff model under three climate change scenarios. A forth scenario —denoted meanRCM— was created by averaging the CFs from the selected RCMs. Reference evapotranspiration for the climate change scenarios was estimated from corresponding temperature data.

Irrigation water demand in the IP will be higher due to increased evapotranspiration and reduced precipitation. Evapotranspiration CFs were calculated from the control and climate change series and applied to total water demand; climate change precipitation series were subtracted to obtain future irrigation water demands.

2.4 Reservoir aggregation

A stochastic dynamic programming approach (see below) was used to formulate operating rules for hydropower generation in the Iberian system. There are more than 100 hydropower reservoirs with an installed capacity of above 10 MW in the IP, representing approximately 85 % of the total hydropower capacity. Because SDP can only handle three or four reservoirs, it was not possible to include all the relevant reservoirs into the optimization framework. Therefore, the volumes and flows representing the hydrological system were converted to power and energy units, respectively, and aggregated into an *equivalent energy reservoir*.

Irrigation abstractions were converted to energy equivalent in two ways: upstream abstractions were considered as an energy sink in the balance equation of the equivalent energy reservoir, while downstream abstractions were considered as a time-dependent lower bound on hydropower releases. A detailed description of the aggregation methodology and a calculation example are provided in Online Resource 1.

2.5 Power system model

The Iberian power system is managed as a competitive power market that equilibrates power supply and demand. The price of electricity and the traded amount can be estimated using a market equilibrium model with appropriate power supply and demand functions.

We assumed an inelastic electricity demand that varies as a function of air temperature, following the degree-day approach used by Valor et al. (2001) in Spain. E-Obs' mean daily temperature data (Haylock et al., 2008) were weighted by Landscan population data (Bright et al., 2008), and divided in cooling (>18 ° C) and heating (<18 ° C) days. A linear regression was used to calculate power demand under each condition, and separate regressions were used to estimate demands for weekends and holidays. The regression models were fitted to daily forecasted electricity demand (OMIE, 2012) for the period July 2007 – December 2011. Previous data were not used because the Iberian power market was created in July 2007.

Four groups of generation technologies were included in the supply function: nuclear; coal and combined cycle gas turbine (CCGT); hydropower; and special regime, which consist of a group of technologies (approx. 60 % renewable) that have special market agreements. Installed capacities were obtained from national yearly reports (REE, 2012; REN, 2012), and marginal costs estimates from CNE (2008). Emission factors were calculated from IDEA (2005) according to the current share of production of each technology within the group. Because the electricity generated under special regime is always cleared regardless of market conditions, it was subtracted from demand. Pumped-storage was not considered; the net production of this technology is close to zero when accumulated over a weekly time step. The data used to describe the power generation technologies, their emission factors and mean annual production are shown in Table 2 in Online Resource 1. Coal and CCGT were merged into one technology and their emission factors were weighted by observed production levels (2008–2011) and averaged.

Because this study aims to assess the impact of climate change on the current power system, it is assumed that installed capacities and marginal costs of every generation technology will remain at current levels. Power demand for the climate change scenario is estimated from the temperature series calculated with the delta change method.

2.6 Stochastic dynamic programming and water values

Hydropower poses several challenges in power system modeling. While hydropower production has a low direct variable cost, it has a high opportunity cost: releasing water in the current time step decreases water availability in future time steps. Therefore, income from present hydropower generation must be balanced against loss of income in an uncertain future that depends on power demand, alternative power sources and uncertain inflows. Furthermore, the coupling of successive time steps by hydropower reservoirs makes the problem dynamic, and its dependence on uncertain inflows requires a stochastic solution.

We used an application of Stochastic Dynamic Programming (SDP) known as the *water value method* (Stage and Larsson, 1961; Wolfgang et al., 2009) to develop rational reservoir operating rules given uncertain future flows. The method consists of calculating the full total cost (immediate cost plus expected future cost) of system operation for each stage and state through the traditional Bellman formulation (1), and then taking the derivative of such costs with respect to the reservoir level (6). The result is the water value (in €/m$^3$, or €/MWh for equivalent energy), which represents the expected value of a marginal amount of water (energy) if it is stored for later use. Intuitively, the difference in expected total costs between two reservoir levels represents the opportunity costs of releasing the corresponding amount of water (energy).

After optimization through SDP, the system is simulated using water values as marginal costs of hydropower in the power supply function; thereby turning the water values into a rule curve for optimal reservoir operation. Note that by minimizing future and expected costs of all power sources (including hydropower) subject to meeting irrigation and power demands, the optimization algorithm acts as the coupling component between the power and the water systems.

SDP was used to determine production levels of thermal (*Nuclear* and *Coal+CCGT*) and hydropower units such as to minimize expected production costs, subject to meeting demand $d_t$ for every period $t$ of the planning horizon $S$. The optimization scheme is run on weekly time steps for the control period (1961–1990) and for the climate change scenario (2036–2065). The state variables used to describe the system at the beginning of each stage $t$ are the equivalent energy storage $E_t$ and, because the inflows show serial correlation, the previous equivalent energy inflow $Q_{t-1}$. Let $\mathbf{c}$ be the $1{\times}I$ vector of constant marginal costs for every non-hydro producer $i$, and $\mathbf{p}_t$ a $1{\times}I$ vector of power production (decision variable) for every producer $i$ during time step $t$. The recursive SDP equation of the optimal value function $F^*(E_t,Q_{t-1})$ can be written as:

$$F_t^*\left(E_t, Q_{t-1}^k\right) = \min_{\mathbf{p}_t} \left[ \mathbf{c}^T \mathbf{p}_t + \sum_{l=1}^{L} a_{kl} \times F_{t+1}^*\left(E_{t+1}, \overline{Q}_t^l\right) \right] \qquad (1)$$

where the inflow serial correlation is represented by a discrete Markov chain: $a_{kl}$ is the transition probability from inflow $Q_{t-1}^k$ in stage $t{-}1$ to inflow $\overline{Q}_t^l$ in stage $t$, estimated for every week of the year from the energy inflow series. Because of computational constraints and the limited length of the simulated inflow series, five inflow classes were defined for each week of the year: very dry (0th – 10th percentile), dry (10th – 30th percentile), average (30th – 70th percentile), wet (70th – 90th percentile) and very wet (90th – 100th percentile). Mean weekly inflows within each inflow class $\overline{Q}_t^l$ were used to calculate the expected future costs in (1); such values provided an accurate representation of the first two moments of the 30-year series.

The problem in (1) is subject to constraints on equivalent energy balance (3), minimum and maximum hydropower generation (see Reservoir Aggregation section in Online Resource 1), minimum and maximum energy storage (2), power demand satisfaction (4) and minimum and maximum installed capacities (5):

$$\underline{E} \leq E_t \leq \overline{E} \tag{2}$$

$$E_t = E_{t-1} + Q_t - \mathbf{u}^T \mathbf{w}_t - H_t, \quad t = 1, \ldots, S \tag{3}$$

$$\sum_{i=1}^{I} p_{i,t} = d_t - H_t, \quad t = 1, \ldots, S \tag{4}$$

$$p_{i,t} \geq 0, \quad t = 1, \ldots, S; \ i = 1, \ldots, I \ ; \quad p_{i,t} \leq \overline{p}_i \quad t = 1, \ldots, S; \ i = 1, \ldots, I \tag{5}$$

where $d_t$ and $H_t$ are scalars of inelastic electricity demand and total hydropower production, respectively, for time step $t$. $\mathbf{u}$ is an energy conversion factor, and $\mathbf{w}_t$ is a vector of upstream irrigation water demand at time step $t$ (see the Reservoir aggregation section Online Resource 1). A curtailment cost of 180 €/MWh —which is the maximum price of electricity allowed in the MIBEL— was used when the reservoir was unable to satisfy irrigation demands. Mean weekly power and irrigation demands are used during the optimization phase. The water values $\theta$ (€/MWh) are calculated as:

$$\theta = \frac{\partial F}{\partial E} \approx \frac{\Delta F}{\Delta E} \tag{6}$$

where the optimal value function $F$ has units of € and the equivalent energy storage $E$ has units of MWh.

Finally, the water values of the corresponding week and inflow state are added to the power supply function and the system is simulated with the calculated 30-year series of equivalent energy inflow, power demand and irrigation demand. The include production levels of every technology, production costs, reservoir releases and energy storage at every time step $t$.

## 3 Results

### 3.1 Rainfall-runoff model

The rainfall-runoff model provided reasonable results for most of the calibration sub-catchments: weekly Nash-Sutcliffe Coefficients (NSC) for river discharge were above 0.5 and water balance errors, WBE=(sim−obs)/obs, below 30 % (see Table 3 in Online Resource 1). This performance is reasonable considering the coarse spatial resolution of the input data (data pixels of approx. 20–25 km$^2$) and the limited number of large unregulated calibration catchments in the IP. Weekly observed and simulated river discharge on selected calibration sub-catchments are shown in Figs. 3–8 in Online Resource 1. Because of the large number of dams, the annual water balance error was used to evaluate model performance in simulation

catchments. In catchments bounded by a reservoir at the downstream outlet, observed annual releases were used to evaluate model performance, instead of observed river discharge.

## 3.2 Climate change scenario

The results that depend on different RCMs are reported for the average scenario (meanRCM), with the minimum and maximum values observed among the individual RCMs shown on parenthesis. The results for each RCM are shown on Table 4, in Online Resource 1. On average across simulation catchments, the estimated CFs for all scenarios suggest that: i) temperatures may rise between 1.1 °C (0.5–2.3) in spring and 3.6 °C (3.3–3.7) in late summer; ii) precipitation may increase by up to 13 % (10–26) in winter, but decrease by up to 49 % (46–57) in summer; and iii) reference evapotranspiration is expected to increase by 9–18 % (5–28) throughout the year. Monthly changes on temperature, precipitation and reference evapotranspiration for every simulation sub-catchment and climate change scenario are shown in Tables 5, 6 and 7, respectively, in Online Resource 1.

## 3.3 Reservoir aggregation and power system model

The largest hydropower reservoirs in the Peninsula (>10 MW) were aggregated into one equivalent energy reservoir. We estimated that lower river runoff caused by climate change will cause a reduction of 19 % (13–30) in mean annual energy inflows to the equivalent reservoir. Higher evapotranspiration rates may increase total water demands by 13.3 % (12.2–15.0). Changes in temperature patterns will shift power demand from winter to summer months, while mean annual demand will remain constant. The weekly variation on energy inflows, irrigation demand and power demand caused by climate change is shown in Fig. 9, in Online Resource 1.

## 3.4 Stochastic dynamic programming and water values

The result of solving the SDP in (1) and taking the derivative of the costs of satisfying power demand with respect to the reservoir level (6) is a water value table (WVT) indicating the expected value of a marginal amount of water (energy) in the reservoir. Figure 1 shows WVTs for the control (a) and the average climate change (b) scenarios. The expected value of water depends on the week of the year, the reservoir level and the inflow state. For example, the range of water values for mid April in the control scenario (Fig. 1a) is 0–57 €/MWh if the inflow state is *very wet*, while the range is 57–77 €/MWh if the inflow state is *very dry*. In the first case, high inflows and high reservoir levels are likely to cause unproductive spills when the reservoir level is high (value of 0 €/MWh), while high inflows and low reservoir levels mean that hydropower production can substitute the most expensive alternative energy source (coal and gas, at 57 €/MWh), without the risks of unproductive spills. In the second case, low inflows and high reservoir levels mean that hydropower can substitute coal and gas generation (57 €/MWh). With low reservoir levels, the probability of staying in a very low inflow state and being unable to supply irrigation (with a curtailment cost of 180 €/MWh) brings the water value up to 77 €/MWh.

The impact of climate change on water values is considerable, with implications for reservoir management. Lower inflows and higher irrigation demands increase water values (Fig. 1b), which increases the price of hydropower and reduces hydropower production. The dark red area —representing volume that must be stored to satisfy future irrigation demand— becomes larger, resulting in a more conservative reservoir operation policy. In dry years,
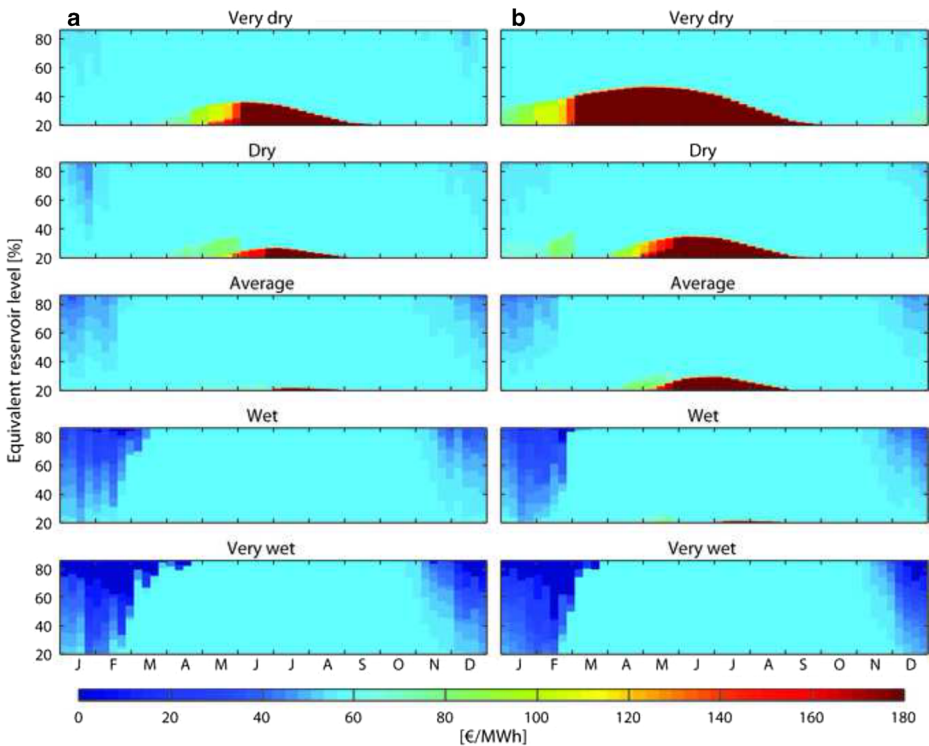
**Fig. 1** Water value tables (€/MWh) for **a**) control and **b**) average climate change (meanRCM) scenarios

periods in which increments of reservoir storage must be conserved starts earlier in the year, reducing hydropower operations to secure irrigation supplies for the rest of the year.

The irregularities observed in the WVT are due to inflow transition probabilities derived from the inflow simulations. For instance, in the climate change scenario (Fig. 1b), until early March in the dry inflow state there is a non-zero probability of moving from a *dry* to a *very dry* inflow state, so the risk of not supplying future irrigation demand raises the expected water value. After early March a *dry* inflow state can either remain *dry* or move to *average*, but will not move to *very dry*, so the water values decrease because there is less risk of not supplying irrigation demand. While the zero probabilities are due to a limited sample size and are not zero in reality, the rainfall-runoff model indicates that lower precipitation and higher temperatures and evapotranspiration will cause dry summers to be more persistent.

When the values in the WVT are used to represent marginal costs of hydropower and added to the power supply function, reservoir segments with water values less than or equal to the market clearing price will be released. The remaining segments will be stored for later use because the benefits of releasing them now are lower than the expected benefits of releasing them in the future. The simulation of the power system under control and future conditions showed a 21 % (15–32) reduction in hydropower generation, from 11.6 to 9.2 % (7.9–9.9) of the mean annual generation. Nuclear and special regime generation remained at 17.8 and 30.2 %, respectively; while coal and CCGT increased by 6.1 % (4.5–8.8), from 40.4 to 42.8 % (42.2–43.9) of the mean annual generation. Changes in the energy mix increased annual $CO_2$ emissions by 6.2 % (4.6–8.9), from 71.6 to 76.1 (74.9–78.0) million tons.

It was not possible to validate simulated hydropower production under the control scenario because actual generation data is not available for all the aggregated reservoirs. However, as volume time series are available for an increasing number of reservoirs since 1966, we could contrast observed and simulated *useful relative energy storage*, defined as $(E_t - \underline{E})/\overline{E} - \underline{E})$. Fig. 2 shows that using the WVTs as rule curves for reservoir operation resulted in a reasonable reservoir management policy that reproduces annual and inter-annual patterns of energy storage. Note that actual reservoirs were managed individually to satisfy several objectives and constraints, while our methodology only considers cost-optimal hydropower generation and satisfaction of irrigation demands.

Figure 3 compares observed and simulated weekly reservoir levels. There is a clear difference in seasonal reservoir management between observed (a) and simulated (b) scenarios. Observed levels are much smoother than simulated ones, possibly because the former results from the sum of more than 100 individual management decisions (and their constraints) while the latter results from one decision: releases from the equivalent energy reservoir to minimize total costs. Lower inflows and higher irrigation demand in the average climate change scenario increased the risk of irrigation curtailment (as shown in Fig. 1b), so reservoir levels before the irrigation season are kept higher in the climate change (Fig. 3c) than in the control scenario (Fig. 3b) in order to conserve flows to meet summer irrigation demands.

## 4 Discussion and conclusions

The purpose of this study is to assess the impact of climate change on the present Iberian power system through a coupled water-power model. We found that climate change can have a large impact on the power system of the Iberian Peninsula: hydropower production will decrease while thermal generation from coal and CCGT will increase, with a significant portion of the power demand shifting from winter to summer. Our results agree with those of Lehner et al. (2005), who find similar reductions in developed hydropower potential in Portugal and Spain by the 2020s. The same seasonal shift in power demand is also predicted by Isaac and van Vuuren (2009) in a study of the domestic sector at the global scale. Our findings for the Iberian power system differ from those of SINTEF (2011) for the Nordpool area and Seljom et al. (2011) for Norway: precipitation in these regions is expected to increase
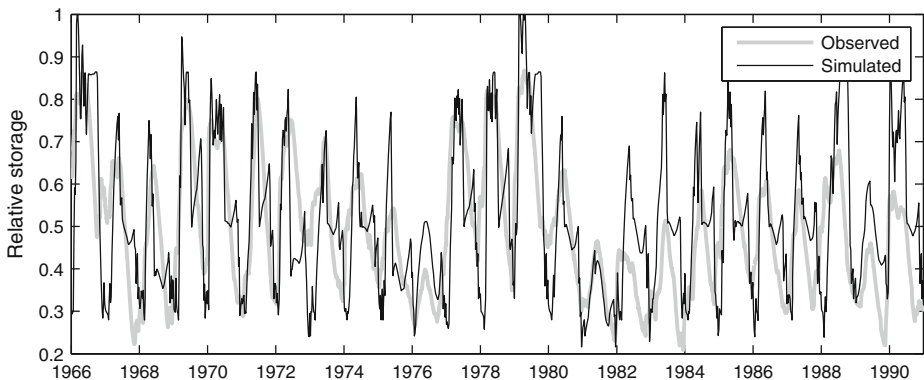


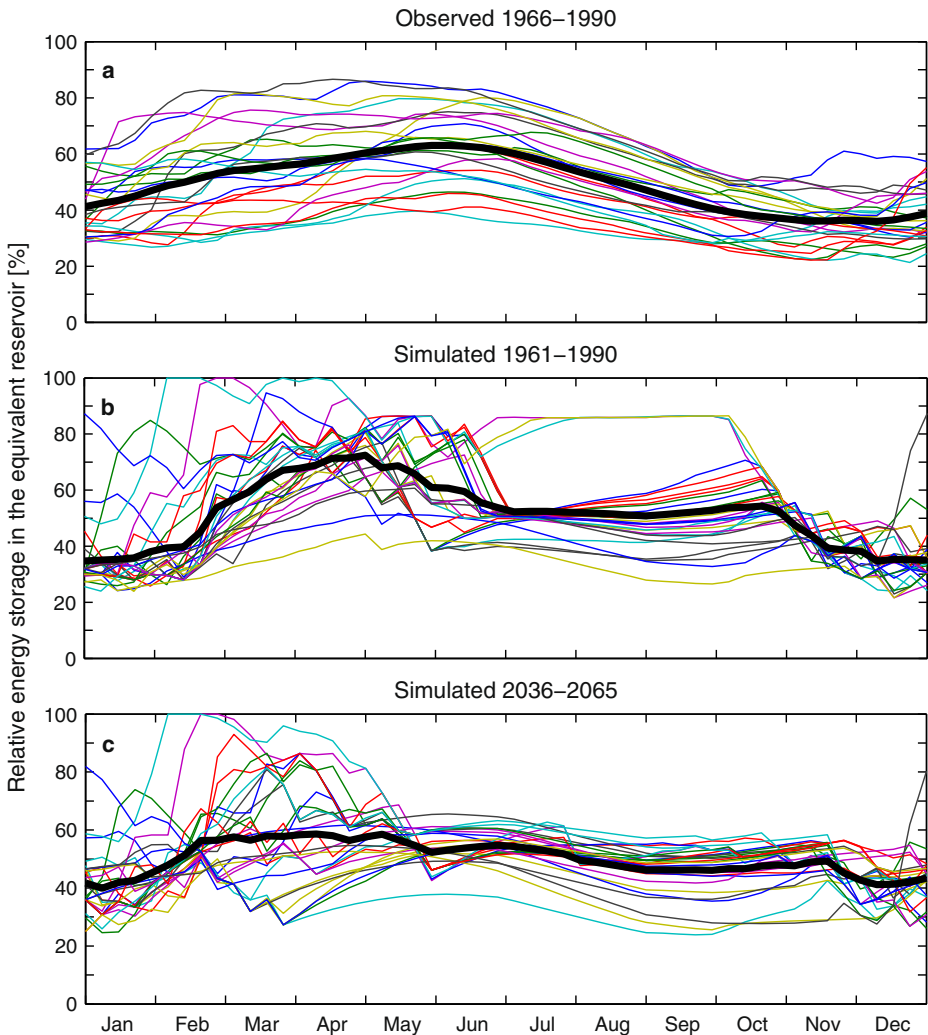Fig. 2 Useful relative energy storage: observed and simulated

**Fig. 3** Annual effective energy storage: **a)** observed, **b)** control and **c)** average climate change scenarios. Thin, color lines represent individual years; thick black lines represent the average year

as a consequence of climate change, thereby increasing hydropower production. This high-lights the importance of performing such assessments at a regional level.

SDP has been demonstrated to be an appropriate tool to quantitatively assess some of the components of the water-energy nexus. However, the results of this study are uncertain because of uncertain impacts of climate change on atmospheric forcings and because of the various simplifications and assumptions used in the analysis. This resulted in uncertainty on the model's parameters and input data (e.g. the rainfall-runoff model, power supply and demand, and the uniform temporal irrigation pattern for all of the basins in the peninsula), and on the model structure (e.g. the rainfall-runoff model, the use of fixed reservoir heads, the assumption of irrigation as a surface water user only, and the assumption of irrigation as the only significant water user). The most significant source of uncertainty is the climate change

scenarios used to generate input data. This was addressed by running the optimization/ simulation framework using scenarios from three different RCMs. It was found that the results vary considerably depending on the scenario. For instance, the CLM model showed the most severe precipitation reductions and temperature increases, which resulted in considerably higher hydropower reductions (and thermal power increases) than the other models. Despite the differences among the results from the three climate change scenarios, the results are still robust: the sign of the change and the order of magnitude is constant among scenarios.

An important potential impact of climate change on the power system is the reduction of thermoelectric generation because of lower river discharge and higher river water temperatures (Forster and Lilliestam, 2010; van Vliet et al., 2012; Rubbelke and Vogele, 2013). Modeling this effect through a detailed description of the hydrological system in rivers with thermoelectric generation would have made the problem intractable. It may be possible to develop a method to aggregate the cooling water demands (in terms of river flow and temperature) to an equivalent demand, but that is beyond the scope of the study.

The most important limitations of the applied method are the spatial aggregation of the hydrological system and the temporal aggregation of the power system. The hydrological system had to be aggregated into an equivalent energy system because of the limit on the number of reservoirs that SDP can handle. This aggregation ignores the physical boundaries between the basins; for instance, the model allows irrigation from a dry catchment to be supplied with resources from a wet catchment. Furthermore, because the results were not disaggregated, we can only draw conclusions about energy mix and reservoir management at the peninsula level. While local impacts of climate change are aggregated to the equivalent reservoir, the adaptation strategy from the equivalent reservoir cannot be translated back to the local (sub-catchment) level. It may be possible to provide local-scale conclusions using disaggregation techniques to convert results from the equivalent reservoir to local reservoirs, as done in the EMPS model (Doorman, 2009). Another solution is to use other optimization techniques, such as stochastic dual dynamic programming (Pereira and Pinto, 1991), that allow simultaneous optimization of many reservoirs.

Using hourly time steps would allow a more realistic representation of the power system, including a better representation of the power supply and demand functions, and the inclusion of pumped-storage hydropower. However, hourly time steps would have made the problem computationally intractable. Some alternatives to include production and price variability within a week would be to divide the week into a few *load segments* with a certain demand profile (e.g. Wolfgang et al., 2009) or to derive *hydropower revenue functions* for each week (e.g. Madani and Lund, 2009).

Insights from the coupled water-power model suggest that climate change may have significant impacts on reservoir operations. Lower inflows will encourage more conservative reservoir policies to ensure the satisfaction of irrigation demands, although such policies are likely to conflict with environmental objectives. On the other hand, changes in power demand patterns can align hydropower and irrigation releases in time, reducing trade-offs between these uses. A considerable reduction in hydropower generation is likely to hinder climate change mitigation efforts by increasing $CO_2$ emissions and by limiting hydropower's ability to complement intermittent renewable energy sources like wind and solar power.

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