AGU100 ADVANCING EARTH AND SPACE SCIENCE

Water Resources Research

RESEARCH ARTICLE

10.1029/2017WR022289

Key Points:
- Future impact of climate change and energy policies on hydropower production and revenue are comparatively assessed using quantitative indicators
- Climate change is expected to induce a loss in electricity production down to -27% in Alpine ice melt-dominated hydropower systems by 2050
- Energy policies may have stronger impact than climate change leading to an increase in hydropower revenue up to about +181%

Supporting Information:
- Supporting Information S1
- Figure S1

Correspondence to:
D. Anghileri,
daniela.anghileri@sccer-soe.ethz.ch

Citation:
Anghileri, D., Botter, M., Castelletti, A., Weigt, H., & Burlando, P. (2018). A comparative assessment of the impact of climate change and energy policies on Alpine hydropower. *Water Resources Research*, *54*. https://doi.org/10.1029/2017WR022289

Received 29 NOV 2017
Accepted 16 OCT 2018
Accepted article online 24 OCT 2018

A Comparative Assessment of the Impact of Climate Change and Energy Policies on Alpine Hydropower

D. Anghileri[1,2], M. Botter[1], A. Castelletti[1,3], H. Weigt[4], and P. Burlando[1]

[1]Institute of Environmental Engineering, ETH Zurich, Zurich, Switzerland, [2]Department of Geography and Environment, University of Southampton, Southampton, UK, [3]Department of Electronics, Information and Bioengineering, Politecnico di Milano, Milan, Italy, [4]Department of Business and Economics, University of Basel, Basel, Switzerland

Abstract Scientific literature has mostly focused on the analysis of climate change impacts on hydropower operations, underrating the consequences of energy policies, for example, increase in Variable Renewable Sources (VRSs) and CO_2 emission permit price, on hydropower productivity and profitability. We contribute a modeling framework to assess the impacts of different climate change and energy policies on the operations of hydropower reservoir systems in the Alps. Our approach is characterized by the following: (i) the use of a physically explicit hydrological model to assess future water availability; (ii) the consideration of electricity price scenarios obtained from an electricity market model accounting for the future projected European energy strategies; and (iii) the use of optimization techniques to design hydropower system operations in response to the projected changes. Through the application to the Mattmark system, a snow- and ice-dominated hydropower system in Switzerland, we demonstrate how the framework is effective in exploring the sensitivity of Alpine hydropower to changes in water availability and electricity price, in quantifying the uncertainties associated to these projections and in identifying the value of reoperation strategies. Results show that energy policies may have more significant impacts on hydropower operations than climate change and, as such, are worth considering in impact assessments studies. The reduction of water availability due to climate change is expected to induce a loss in electricity production down to −27% by 2050. Changes in electricity price, instead, may have up to 6 times stronger impact than climate change, leading to an increase in hydropower revenue up to about +181%.

1. Introduction

Hydropower is a major source for electricity production in the Alps. There are about 550 large hydropower plants (i.e., larger than 10 MW) in the Alpine area comprising Switzerland, Italy, Austria, Slovenia, France, and Germany, with an overall installed capacity of about 46,000 MW (Eurostat, 2016; Swiss Federal Office of Energy, [SFOE], 2016). This electricity is mostly generated by storage systems, which have the possibility to accumulate water over long periods and release it when electricity demand or price is high. In most of these systems, the hydrological conditions define the amount of water yearly available and, consequently, the yearly power generation. In the large majority of cases, electricity prices drive the timing of this production. In the last few decades, both these drivers have experienced substantial variations following hydroclimatic and socioeconomic changes. These are expected to persist in the future and to represent a major challenge to Alpine hydropower system operations.

Climate change is likely the most relevant challenge when considering future water availability (Bates et al., 2008). The main effects of climate change in the Alps are changes in seasonal snow cover duration and spatial extent on the short term (e.g., Barnett et al., 2005; Magnusson et al., 2010; Steger et al., 2013) and glacier retreat on the middle and long term (e.g., Huss, 2011; Huss et al., 2008; Zemp et al., 2006). These are expected to modify the Alpine hydrological regime substantially, ultimately impacting hydropower productivity (Beniston, 2003; Farinotti et al., 2012; Fatichi et al., 2015; Hänggi & Weingartner, 2012; Viviroli et al., 2011). Moreover, the projected hydrological shift from low-frequency processes, that is, snow and ice melt, to high-frequency rainfall-driven streamflow patterns, will accelerate the catchment response to precipitation events, enhance the variability of reservoir inflows, thus calling for a modification of the current hydropower system operations (e.g., Brekke et al., 2009; Gobiet et al., 2014; Haguma et al., 2014).

The second important challenge is coming from the socioeconomic aspects of the energy system, that is, the recent global process of renovation of the energy sector toward low-carbon generation targets, the effort to improve energy efficiency, the nuclear phase-out, and the increasing share of e-mobility (da Graça Carvalho, 2012). European electricity markets have experienced dramatic changes in the last years following the massive introduction of Variable Renewable Sources (VRSs), that is, solar and wind (Haas et al., 2011), and the share of solar and wind energy sources will further increase in the future to meet the European Union (EU) renewable energy target by 2020. VRSs are typically intermittent, that is, their electricity production is highly dependent on the inherent stochastic variability of the sources and, therefore, only partially predictable, have negligible variable cost of production, and have been largely subsidized (e.g., International Energy Agency [IEA], 2015a; Ketterer, 2014). These factors have lowered electricity prices, causing smaller incomes to traditional electricity sources and increased price volatility, thus inducing hydropower storage systems to flexible operations and imposing higher maintenance cost (e.g., Gurung et al., 2016; IEA, 2015a). These effects will likely further amplify in the future because of the expected increase in electricity demand due to the spread of electrical vehicles (e.g., Shepherd et al., 2012), demographic trends (e.g., York, 2007), climate-induced change in the electricity demand (e.g., Bartos et al., 2016; Christenson et al., 2006; Damm et al., 2017), and the reduction of baseload electricity production in countries planning to phase-out nuclear power plants (among which Germany, Belgium, and Switzerland in Europe) (Aune et al., 2015).

Electricity markets can be indirectly impacted by climate change in many ways. For example, climate change might induce an increase in the electricity demand for cooling purposes (i.e., air conditioning), reduce the water available for hydropower production, as already mentioned, and increase the temperature of rivers which are used for cooling purposes of thermoelectric (nuclear and fossil-fueled) power (see, e.g., Mima & Ciriqui, 2015; Van Vliet et al., 2013, and references therein). These effects would be mostly visible during extreme meteorological events. There is also evidence that the last heat waves in Europe affected electricity prices. For example, Pechan and Eisenack (2014) find an average price increase of 11% in the German spot market during the heat wave of 2006. Estimating the uncertainty of climate change impact on electricity prices is a topic of current research, and few studies are available so far. Among these, Van Vliet et al. (2013) predict an increase in the electricity prices for most European countries for the period 2031–2060 with small price variations of about 5% depending on the climate scenario considered (either SRES B1 or A2).

As a consequence of the combined effect of the above mentioned challenges, fast dynamical and uncertain streamflow and price generation processes will characterize hydropower production in the future. In such an overly variable and changing context, current traditional reservoir operating strategies may prove inadequate (e.g., Mateus & Tullos, 2016; Palmer et al., 2008; Watts et al., 2011). This will likely force hydropower system operators to change their current operating strategies in favor of higher flexibility and reliability in order to cope with changed water availability and price structure.

Most of the literature on future impact assessment on hydropower systems has focused on the effect of climate change on water availability both at the local scale, that is, analyzing one or several catchments (e.g., Farinotti et al., 2012; Fatichi et al., 2015; Schaefli et al., 2007) and at the global scale, that is, focusing on continental scales or the entire globe, (e.g., Hamududu & Killingtveit, 2012; Lehner et al., 2005; Ng et al., 2017; Schaefli, 2015). Implications of changed water availability on hydropower systems are qualitatively discussed in most publications, while only few studies perform a quantitative impact analysis (e.g., Anghileri et al., 2011; Gaudard et al., 2014; Terrier et al., 2011). In most of these studies, the existing reservoir operating rules are usually adopted to simulate the system operations with future hydrological inflows, thus neglecting the adaptation potential of reservoir systems. Seldom adaptation measures, including reoperation (e.g., Anghileri et al., 2011) or structural (e.g., Farinotti et al., 2016) measures, are explored.

Much less attention has been devoted to assess the impact of energy and economic policies on future hydropower, although electricity prices are arguably considered the largest source of uncertainty in hydropower operations (Gaudard et al., 2016). Examples include the coupling of hydropower systems with VRSs (e.g., François et al., 2014) and changes in the electricity demand (e.g., Maran et al., 2014). Electricity prices are usually modeled with deterministic empirical relations estimated from historical records (e.g., Gaudard et al., 2016). There are few studies focusing on how electricity price may change in the future and how this will affect hydropower operations (e.g., Gaudard et al., 2014; Van Vliet et al., 2013). A common assumption is to describe the evolution of electricity prices due to climate change by modeling the relation between electricity prices, demand, and temperature (e.g., Kern et al., 2011, 2014). No study so far, according to the authors'

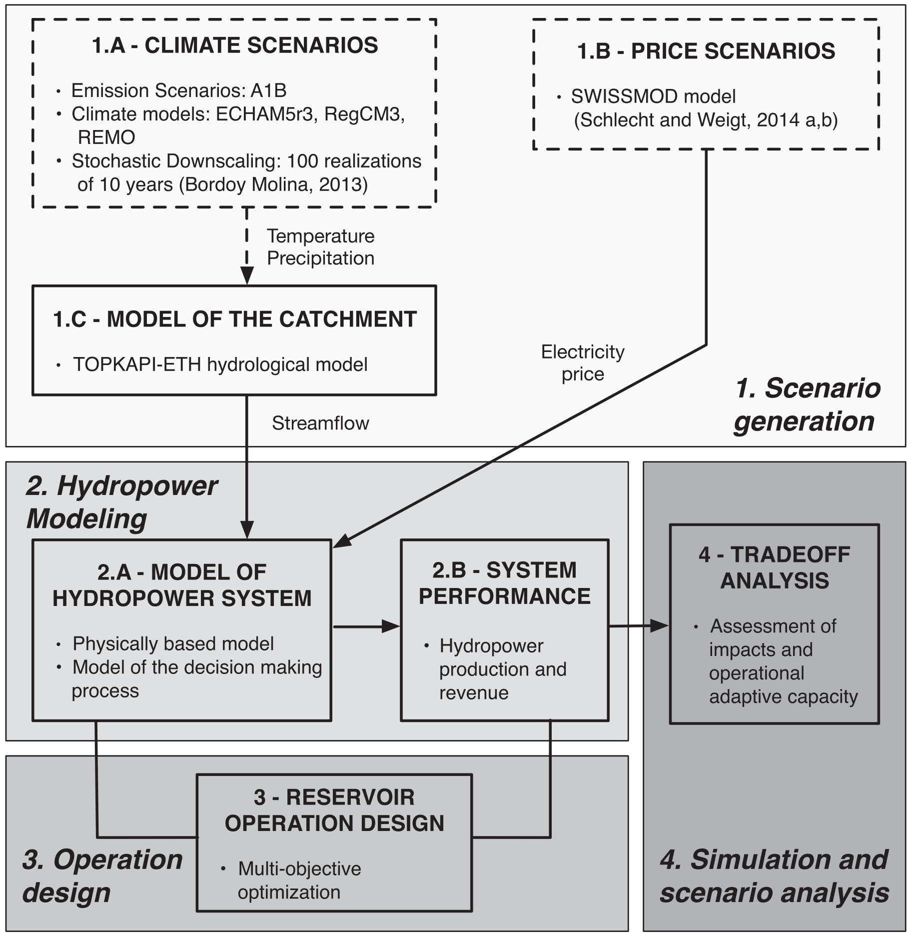

Figure 1. Flowchart of the modeling framework adopted in this paper. Dashed boxes refer to analysis developed in previous studies.

knowledge, addresses how hydropower operations might be affected by political and economic scenarios such as different development paths for VRSs or CO_2 permit price.

In this context, the objective of this paper is to compare the effect of climate change and energy strategies on Alpine hydropower operations. We develop a modeling framework that is capable of (i) simulating the effect of different and uncertain water availability and electricity price projections on hydropower system operations and (ii) designing suitable adaptation strategies by reoptimizing reservoir operations under uncertain changing conditions. Water availability projections are obtained using a physically explicit hydrological model driven by stochastically downscaled climate change scenarios of precipitation and temperature. Electricity price projections are obtained by simulations of an electricity market model that accounts for the generation mix, including VRSs, the electricity demand, the CO_2 emission permit price, and other elements that are determinant in forming electricity price. We adopt a stochastic, multiobjective optimization technique to estimate current hydropower system operations and their possible future evolution in response to the above mentioned scenarios up to 2050. The multiobjective nature of the optimization algorithm allows to explore alternative hydropower operating strategies, diversely balancing the different operating purposes, for example, electricity supply and revenue. The stochastic nature of the optimization algorithm allows to cope with the inherent uncertainty characterizing reservoir inflows and electricity price fluctuations, thus avoiding the unrealistic assumption of perfect knowledge of the two.

Overall, our modeling framework allows understanding how much impact global changes in climate and energy policies could have on hydropower operations at the local scale, disentangling which of the two drivers could be the most impacting one. In summary, the paper contributes three novel aspects: (i) we analyze the effects of changes in water availability and electricity price scenarios when considered alone and jointly, showing that their combined occurrence might drive nonlinear effects on the impact assessment; (ii) we explicitly account for the uncertainty of (a) natural climate variability when producing climate scenarios by adopting stochastic downscaling techniques and (b) both reservoir inflows and electricity price when exploring the future reservoir operations, thus assessing more robust impacts; (iii) we explicitly account for different adaptation measures designed to account for multiple hydropower performance metrics, specifically electricity production and revenue.

The modeling framework is applied on the real-world case study of the Mattmark reservoir, one of the largest hydropower reservoirs in Switzerland. The system has a total installed capacity of 256 MW and almost 30% of its catchment area is covered by glaciers. The Mattmark setup is representative of many storage systems in Switzerland, one of the countries with the highest hydropower annual generation in Europe (International Commission on Large Dams [ICLD], 2014; IEA, 2015b). Hydropower is currently contributing to about 60% of the national production of electricity, while the remaining 40% is essentially covered by nuclear power production (SFOE, 2016). Being one of the historical power sources in the country, Swiss hydropower systems are well designed for what concerns both infrastructures (e.g., turbine efficiency) and operations, but they will be substantially threatened by both climate change, for example, glacier retreat (e.g., Fatichi et al., 2015; Farinotti et al., 2016), and socioeconomic changes, for example, the nuclear phase out, which is planned within the next decades (SFOE, 2012). Although not part of the European Union, Switzerland is very much connected to the other European countries because of its geographic and economic centrality. As such, the energy policies established at the European level affect significantly the electricity price of the country. These characteristics make the study site particularly interesting for comparing the absolute and relative impact of climate change and socioeconomic policies on the hydropower potential and for exploring how adaptation strategies can lessen such impact.

The paper is organized as follows. Section 2 presents the general modeling framework. In particular, it describes the scenarios of water availability and electricity price considered in this study, the hydropower system optimization model, and the experimental setup. Section 3 describes the Mattmark hydropower system. Section 4 presents the results of the trade-off evolution driven by water availability and electricity price scenarios. Finally, section 5 concludes the paper summarizing the main results and discussing the limitations of the analysis.

2. Material and Methods

The modeling framework developed in this paper is shown in Figure 1 and consists of four steps: (i) scenario generation, (ii) hydropower modeling, (iii) operation design, and (iv) simulation and scenario analysis.

2.1. Scenario Generation

We generate the water availability scenarios by simulating the basin response through the distributed, physically based hydrological model Topkapi-ETH fed with climate change scenarios developed in a previous research project (see Bordoy Molina, 2013; Fatichi et al., 2015). Price scenarios are taken from Schlecht and Weigt (2015) as detailed below.

2.1.1. Climate Change Scenarios and Hydrological Model

The climate change scenarios considered in this study comprise three different climate model realizations stemming from three Regional Climate Models (RCMs), driven by one General Climate Model, and one emission scenario. We consider the middle emission scenario A1B (Nakicenovic et al., 2000), the General Climate Model ECHAM5 (Roeckner et al., 2003), the RCMs ECHAM5r3 (Roeckner et al., 2003), RegCM3 (Pal et al., 2007), and REMO (Jacob, 2001). A stochastic downscaling procedure is used to spatially and temporally downscale the time series of precipitation and temperature obtained by the climate models to the resolution required by the hydrological model Topkapi-ETH. The procedure consists in calibrating two stochastic weather generators for simulating hourly, multisite precipitation and temperature and computing monthly factors of change for both the mean and the variance for each decade from 2011 to 2050 with respect to the control scenario. These are used to reparameterize the calibrated weather generators to simulate time series that account for the climate change signal and the intrinsic stochastic variability of local climate. More details on the stochastic downscaling procedure can be found in Bordoy Molina (2013) and Bordoy Molina and Burlando (2014). In the following analysis, we consider 100 stochastic realizations of 10 years each generated in a previous work (Fatichi et al., 2015). Each future decade as well as the control scenario are assumed to be stationary. While we acknowledge that the A1B scenario has been superseded by the new RCPs (Van Vuuren et al., 2011), we consider that its use is not problematic as the projected changes from the CMIP3 experiment simulations (considering the A1B scenario) and those from the CMIP5 experiment (considering the RCP scenarios) are remarkably similar (Knutti & Sedláček, 2013). Similarly, we consider appropriate also the use of only three model chains, as opposed to multimodel scenarios, as it has been demonstrated that, for scenario horizons up to 2050, the dominant source of uncertainty is that of the (stochastic) natural variability of climate (Fatichi et al., 2016), which is already taken into account by the scenarios we use (Bordoy Molina, 2013; Bordoy Molina & Burlando, 2014).

The hydrological model Topkapi-ETH is an evolution of the original rainfall-runoff model Topkapi (Ciarapica & Todini, 2002; Liu & Todini, 2002) and has been used in several previous works to represent catchments with complex terrains (e.g., Ragettli & Pellicciotti, 2012), and catchments where water infrastructures affect significantly the natural hydrological regime (e.g., Finger et al., 2012; Fatichi et al., 2015). Topkapi-ETH is a physically explicit model using a regular grid spatial representation of the catchment area. The model accounts for the main hydrological processes that are relevant in Alpine catchments, that is, snow and ice melt and accumulation processes, soil infiltration and excess, surface and subsurface flow, and evapotranspiration (see Fatichi et al., 2015, for more details). In particular, ice melt and accumulation dynamics are modeled without accounting for ice mass redistribution due to glacier movements. Topkapi-ETH is also capable of describing the alteration of natural flow patterns due to anthropogenic structures through a spatially distributed network of reservoirs and artificial diversion channels, which are modeled through mass balance equations. The reservoir operations is described using a closed-loop operating rule describing the reservoir release as a function of reservoir storage and day of the year (see section 2.3).

2.1.2. Electricity Price Scenarios

The European market development and the resulting prices for Swiss hydropower are based on the scenario assessment described in Schlecht and Weigt (2015) that provides publicly available hourly price curves every 5 years from 2015 to 2050. Future scenarios of electricity prices are based on the Swiss and European energy road maps. They capture the transition from the former fossil-nuclear-dominated generation mix to a system characterized by a high share of renewable generation, a projected increase in energy demand mostly due to population growth, a planned increase in CO_2 emission permit price, and other elements which are determinant in forming electricity price. More details are included in the supporting information. The price scenarios are obtained through a model of the Swiss electricity market called Swissmod (Schlecht & Weigt, 2014). The model describes the Swiss electricity grid with nodes representing power sources and sinks, and edges representing transmission lines. It describes also the interconnections of the Swiss transmission system to the neighboring countries, thus being able to simulate electricity import and export with Austria, Germany, France, and Italy. Swissmod accounts for diverse generation mix, comprising, among others, nuclear power plants, other conventional thermal power plants, VRSs, and hydropower plants. The model designs hourly power production and electricity price for each country over a period of 1 year by solving a linear programming problem minimizing total generation cost under given electricity demands, which are taken as exogenous inputs. A summary of the underling modeling approach and the resulting market and price developments is provided in the supporting information.

Within the context of this study, the price scenarios by Schlecht and Weigt (2015) are used as one possible price scenario for every decade we consider in the analysis, and they represent a probable future market development that can be contrasted to the climate-induced hydrological changes to hydropower systems. Given the high uncertainty of future fuel prices, energy and environmental policy developments, potential market design changes, and uncertain technology developments, a single price scenario cannot capture all those impacts. Ideally, a set of different price pathways or uncertainty estimates should be used. However, given the limited availability of price simulations with sufficient temporal resolution for a hydropower operational model, we consider the chosen price scenario sufficient for a first estimate and judgment of the relevance of market drivers and socioeconomic impacts in the context of hydropower assessments.

2.2. Hydropower Modeling

We model the hydropower system with a daily mass balance equation representing the reservoir storage dynamics, plug-flow models of the hydropower network artificial channels, and physically based models of the power plants. The reservoir dynamics is described by the mass conservation equation as follows

$$s_{t+1} = s_t + a_{t+1} - r_{t+1} \tag{1}$$

where s_t (m^3) is the reservoir storage at time t, a_{t+1} (m^3) is the reservoir inflow, and r_{t+1} (m^3) is the reservoir release from time t to $t+1$. In our mathematical notation, the time subscript of a variable indicates the time instant when the variable value is deterministically known. Following Soncini-Sessa et al. (2007), the release is expressed by means of a nonlinear function of storage, inflow, and release decision, which also accounts for the spillway rating curve and other physical constraints (e.g., active storage), that is,

$$r_{t+1} = f_t(s_t, u_t, a_{t+1}) \tag{2}$$

where u_t (m^3) represents the water volume to be released between t and $t+1$ according to the reservoir operating rule (see section 2.3).

We consider two performance metrics to assess the current and future hydropower performance, namely, the mean annual electricity production and revenue. The power generated in the ith plant is computed as follows

$$G^i_{t+1} = \eta^i g \rho q^i_{t+1} h^i_t \tag{3}$$

where G^i_{t+1} (MWh) is the production, η^i (-) is the efficiency of the ith plant, g (m/s^2) is the gravitational acceleration, ρ (kg/m^3) is the water density, and q^i_{t+1} (m^3) is the turbined volume in the ith plant from time t to $t+1$. The latter cannot exceed the plant capacity $Q^i_{\max}$ (m^3), that is, $q^i_{t+1} = \min\{r_{t+1}, Q^i_{\max}\}$. The hydraulic head h^i_t (m) is computed from the storage through the storage-stage relationship.

The revenue is computed assuming that the production in each power plant is allocated in the most profitable hours of the day, that is,

$$R^i_{t+1} = \sum_{j=0}^{n^i_{t+1}} \theta_{t+1,j} G^i_{t+1} \tag{4}$$

where R^i_{t+1} (euro) is the daily revenue of the ith plant, $\theta_{t+1,j}$ (euro/MWh) is the electricity price in the jth most profitable hour from day t to $t+1$, and n^i_{t+1} (-) is the daily number of hours in which the ith plant is operated at full capacity, that is, $n^i_{t+1} = \frac{q^i_{t+1}}{Q^i_{\max}} \cdot 24$. Equation (4) incorporates hourly price variability into the objective function which is, however, modeled at the daily time step. In so doing, we can assess how different intraday price patterns, which are projected to significantly change in the future (see section 4.2 and the supporting information), might affect hydropower operations. With this proposed design, we aim for a compromise between model complexity and model detail. The daily formulation allows a more compact model formulation suitable for multiple scenario runs. However, a model setup with only average daily electricity prices would provide a wrong incentive structure as storage hydropower systems aim for maximizing production during high price hours. The accounting for a more detailed hourly profile of prices (in our case $\theta_{t+1,j}$ with $j = 1, 2, \cdots, 24$) prevents this bias. The revenue estimate represents, nevertheless, an upper bound of the actual revenue, because the computation assumes the intradaily price to be perfectly known in advance. This assumption might represent a larger approximation in the future because prices volatility is expected to increase due to higher production by VRSs.

2.3. Operation Design

We describe the operations of the hydropower system by means of closed-loop operating rules (Castelletti et al., 2008) describing the reservoir release decision as a function of the reservoir storage and the day of the year, that is,

$$u_t = \pi(d_t, s_t) \tag{5}$$

where u_t is the release decision (m^3) at time t, π is the operating rule, d_t is the day of the year ($d_t = 1$ representing the first Monday in January), and s_t is the reservoir storage (m^3). The optimal reservoir operating rules are defined as

$$\pi^* = \arg\max_{\pi} \mathbf{J} = |J^{\text{pro}}, J^{\text{rev}}| \tag{6}$$

where J^{pro} and J^{rev} are the two objective functions we consider. They represent the expected value of electricity production (MWh) and revenue (euro) of the N_p plants belonging to the hydropower system computed with respect to the hydropower model exogenous variables, corresponding to the reservoir inflow and the electricity price, over an infinite optimization horizon H, that is,

$$J^{\text{pro}} = \mathop{E}_{a_t,\theta_t}\left[\lim_{H\to\infty} \sum_{t=0}^{H-1} \sum_{i=1}^{N_p} G^i_t\right] \tag{7}$$

Table 1
Summary of the Experimental Setting for the Scenario Analysis

	Scenarios used in optimization	Scenarios used in simulation	Meaning of the experiment
Baseline	control climate + historical price	control climate + historical price	Business-as-usual operations
CC-BAU	control climate + historical price	changed climate + historical price	Business-as-usual operations under climate change
CC-ADA	changed climate + historical price	changed climate + historical price	Operations adapted to climate change
EP-BAU	control climate + historical price	control climate + changed price	Business-as-usual operations under price change
EP-ADA	control climate + changed price	control climate + changed price	Operations adapted to price change
CC-EP-ADA	changed climate + changed price	changed climate + changed price	Operations adapted to both climate and price change

$$J^{rev} = \underset{a_t,\theta_t}{E}\left[\lim_{H\to\infty}\sum_{t=0}^{H-1}\sum_{i=1}^{N_p} R_t^i\right] \tag{8}$$

We formulate the reservoir operation problem as a two objective stochastic optimization problem to account for the hydropower company interests and the goals of the Swiss Energy Strategy 2050. On the one hand, the main aim of a private company on a deregulated market is expected to be the maximization of the revenue (equation (8)). On the other hand, the Swiss Confederation aims at increasing hydropower electricity production (equation (7)) in the following decades to partially compensate for the planned Swiss nuclear phase out, as outlined in the Swiss Energy Strategy 2050 scenarios (Prognos, 2012). A more extensive discussion about the reservoir system operations driven by these two objective functions can be found in Anghileri et al. (2018). The optimal operating rules are then obtained using Stochastic Dynamic Programming. The expected values in equations (7) and 8 are computed with respect to probability density functions describing reservoir inflow and electricity price as two independent cyclostationary stochastic processes (see Anghileri et al., 2018, for more details). The solution of the control problem is a set of Pareto optimal operating policies diversely trading-off the two above mentioned objectives.

2.4. Simulation and Scenario Analysis

The above described modeling and optimization tools are used to analyze how the trade-off between the two objective functions may evolve in time under different scenarios of water availability and electricity prices, specifically 100 scenarios of water availability and a scenario of price for each decade. We consider the optimal operating rules designed under the combination of water availability in the control period and historical electricity prices as baseline. The investigated scenarios are used for two purposes: (i) to simulate how the baseline operating rules perform under different and changing future scenarios (business-as-usual analysis) and (ii) to design new optimal operating rules according to future inflow and price probability density functions (adaptation analysis). More specifically, we simulate the performance of the baseline operating rules when used under future scenarios of water availability or electricity price to estimate the impacts of business-as-usual operating rules under climate change scenarios (CC-BAU) or electricity price scenarios (EP-BAU). Then, we redesign the operating rules according to future scenarios, to estimate the adaptive capacity of the hydropower system to the considered changes, that is, CC-ADA when considering climate change scenarios only, EP-ADA when considering price scenarios only, and CC-EP-ADA when considering both scenarios. In this last case, we combine each climate change decade with the price scenario simulated for the middle year of the same decade (e.g., the decade 2041–2050 is associated to the price in 2045). As we repeat the analysis for every decade, results show the evolution of both impacts and adaptation potential up to 2050. Using stochastic realizations of water availability, we are able to estimate the uncertainty of the impacts due to natural climate variability and contrast this with climate change impacts. Table 1 summarizes the specifics of the different experiments.

One limitation of the data set used for the scenario analysis is that the price scenarios are not based on the same climate inputs used for the hydrological scenarios. While the price scenarios of Schlecht and Weigt (2015) account for general changes on the supply side (i.e., increasing shares of renewables) and input costs (i.e., fuel and permit prices), changes on hydropower inflows, demand patterns, or fossil plant availabilities due to climate change are not considered in Swissmod. Combining all these elements into one consistent framework is still an ongoing research. Consequently, price simulations with sufficient resolution for our assessment are not yet available. However, the proposed model structure as well as the general scenario outlet are designed

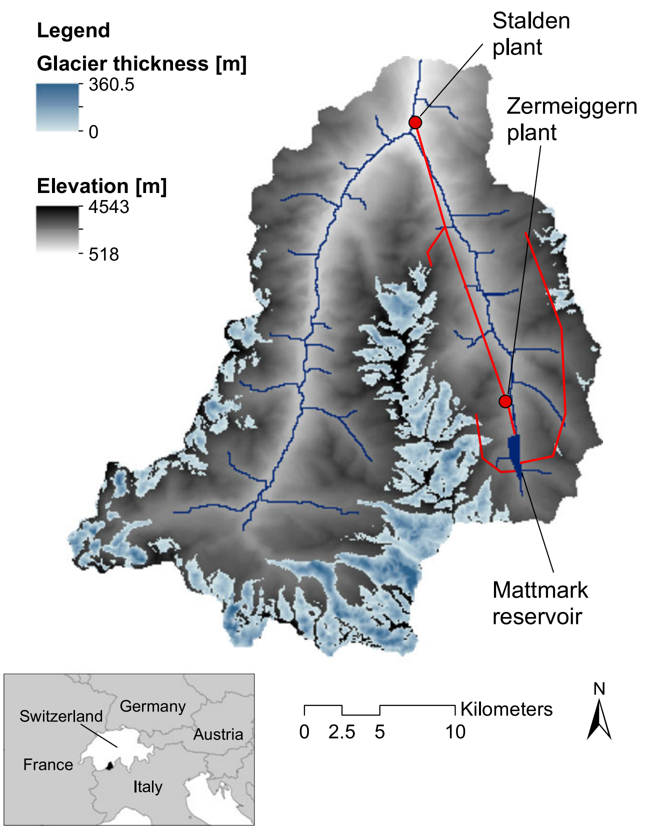

Figure 2. Visp valley including the Mattmark reservoir. The Mattmark hydropower facilities (diversion channels and power plants) are represented with solid red lines and dots. The glacier thickness map represents the ice distribution in the catchment in the 2000s (Fischer et al., 2014; Huss & Farinotti, 2012).

in such a way that once such information is available the analysis can be updated and extended. The obtained numerical results are therefore meant to highlight the importance of a combined assessment.

3. Case Study

The Mattmark hydropower system is located in the Visp Valley in Southern Switzerland (Figure 2). Previous estimates indicate that about 41% of the annual discharge in the entire Visp valley is used for hydropower production by two hydropower systems (Finger et al., 2012). Part of water resources of the catchment are transferred to the Grand Dixence dam, which is located in a nearby valley. The remaining is instead exploited by the Mattmark hydropower system. The Mattmark reservoir has a storage of about 100×10^6 m^3 and it is capable of storing the entire median annual inflow, that is, it has an inflow-to-storage ratio equal to 1 or, in other words, a reservoir storing capacity of 12 months. It produces electricity via two power plants downstream (Zermeiggern and Stalden) with a total installed capacity of 256 MW. The reservoir is fed by a 162-km^2-wide catchment with an ice and snow-dominated hydrological regime characterized by low inflow in winter and autumn and high inflow in summer. Almost 30% of the reservoir catchment area is covered by glaciers (Farinotti et al., 2012), mostly contributing to the late summer inflow. The Mattmark hydropower system is operated since 1965 and follows the typical Alpine storage pattern, with a single drawdown and fill up cycle starting at the beginning of the fall season. The flow used from the hydropower system is returned to the natural water body at the end of the valley. The Zermeiggern plant is both a production and pumping plant. In this paper, we intentionally do not model its pumping activity, because we want to perform an analysis which could be considered representative of most of the hydropower systems in Switzerland and pumped storage plants covers only 4.4% of the national production (SFOE, 2016).

The Mattmark system was already analyzed in previous studies. Finger et al. (2012) investigate the impacts of climate change on the hydrology of the system by using the same hydrological model used in the present work, that is, Topkapi-ETH, with consideration of neither scenarios of electricity prices nor possible adaptation of hydropower operations. We build upon this work by considering a model that describes glaciers dynamics (for the description of the model, see Ragettli & Pellicciotti, 2012) and by representing the hydropower reservoir dynamics with optimized reservoir operating rules, which are intended to describe how the hydropower company could operate the systems under the different scenarios of water availability and electricity prices. Gaudard et al. (2014) analyze the Mattmark system considering both climate change projections and electricity price projections obtained from an empirical relation accounting for temperature and electricity consumption observed in the past. Yet they do not account for the effects induced by different energy policies, which are representative of the electricity market evolution or driven by the transition to low carbon energy society.

The hydrological model setup for the Mattmark case study consists of a 100-m-grid spatial resolution and hourly time resolution. The topography is described according to a Digital Elevation Model available from Swisstopo (https://www.swisstopo.admin.ch/). A proper representation of the current ice mass and the ice melt dynamics is important for a reliable estimate of the future water availability and, thus, reservoir operations. In this paper, we adopt a glacier thickness map computed using the methodology described in Huss and Farinotti (2012) starting from the glacier area estimates of the SGI2010 database (Fischer et al., 2014) to represent the current ice distribution in the catchment (see Figure 2). The model is calibrated using time series of precipitation, temperature, and cloud cover transmissivity recorded at the gauging stations of Zermatt, Visp, and Gornergrat over the period 2009–2014 and validated over the period 1994–2008. The calibration and validation are performed with respect to the daily reservoir net inflow computed via mass balance from the available records of reservoir storage and release over the same periods. These two measurements are not subject to significant measurements errors, especially in hydropower systems. The net inflow calculated

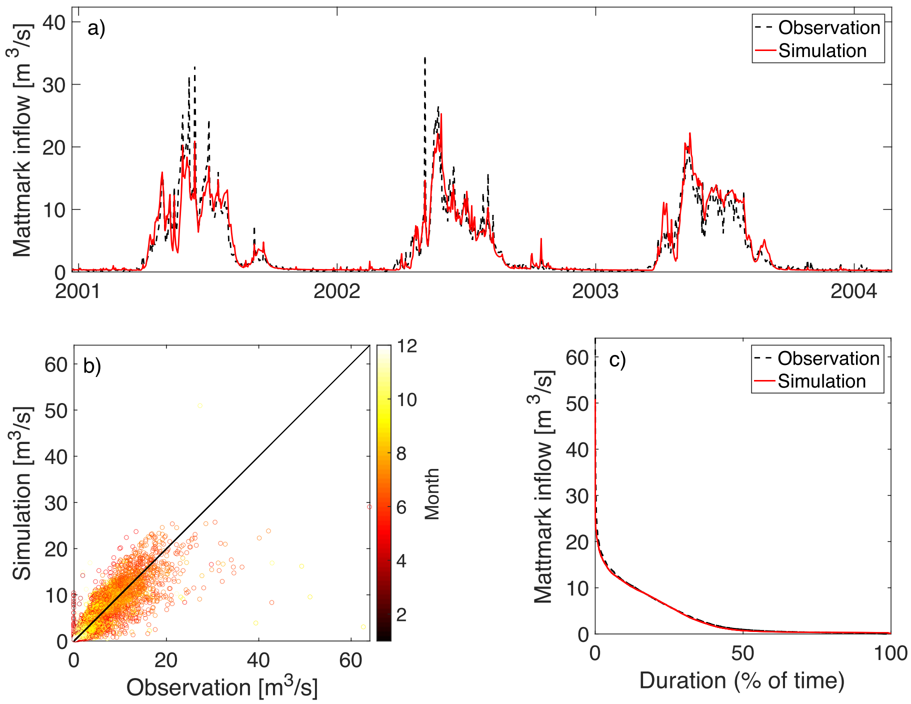

Figure 3. (a) Daily time series of observed (black dashed line) and simulated (red solid line) flow (zoom over the period 2001–2003). (b) Scatter plot of observed and simulated flow (computed over the period 1995–2014). (c) Observed (black dashed line) and simulated (red solid line) flow duration curves (computed over the period 1995–2014).

in this way comprises the surface and subsurface flow, the direct precipitation to and the evaporation from the reservoir. The calibration of Topkapi-ETH is performed by comparing the net inflow with a flow variable accounting for the same components except for evaporation. The evaporation from the reservoir computed using the Priestley-Taylor equation equals 1.5% of the flow used for the calibration. The error in this specific case could be considered negligible.

Figure 3 shows the observed and simulated daily inflow to the reservoir and the flow duration curve. The Nash-Sutcliffe Efficiency (NSE) coefficient computed on daily time series considering a 1-year warm-up period, that is, over the period 1995–2014, is equal to 0.78 and the Root Mean Square Error (RMSE) is equal to 2.36 m^3/s. The model is able to fairly represent the inflow timing, snow and ice melt processes, and low flow periods. Flow peaks are instead underestimated likely because of an underestimation of rainfall, particularly at high elevations. This problem is widely acknowledged in the literature. Isotta et al. (2014), for example, reports that winter high-intensity precipitation is systematically underestimated in gauge measurements all over the Alps by about 8 to 20%. This might result in less snow accumulation and consequently melt in our simulations. Indeed, the seasonal daily RMSE ranges from 0.20 m^3/s in winter to 3.73 m^3/s in summer. The simulated annual cumulative runoff is on average 4% less than the observed one, which confirms the possible underestimation of precipitation as commented above.

4. Results and Discussion

4.1. Climate Change Impact and Adaptation of Hydropower Operations

Figure 4 shows the 10th, 50th, and 90th monthly percentiles computed from the time series of simulated reservoir inflow according to downscaled REMO climate change scenario. The simulation results according to the other two climate change scenarios, that is, downscaled ECHAM5r3 and RegCM3, are included in the supporting information. Each simulated decade is represented with a different color to analyze the evolution in time of water availability for hydropower up to 2050. The annual reservoir inflow volume is projected to decrease in time due to the reduction in glacier extent (see Figure 5). The flow distribution along the year moves from a unimodal function with a peak in June to a bimodal function with a second lower peak in September–October. This is a consequence of the projected increase in temperature, which causes a higher ice melt and an increase in rainfall in contrast to snowfall in late autumn. The snow melt peak happens

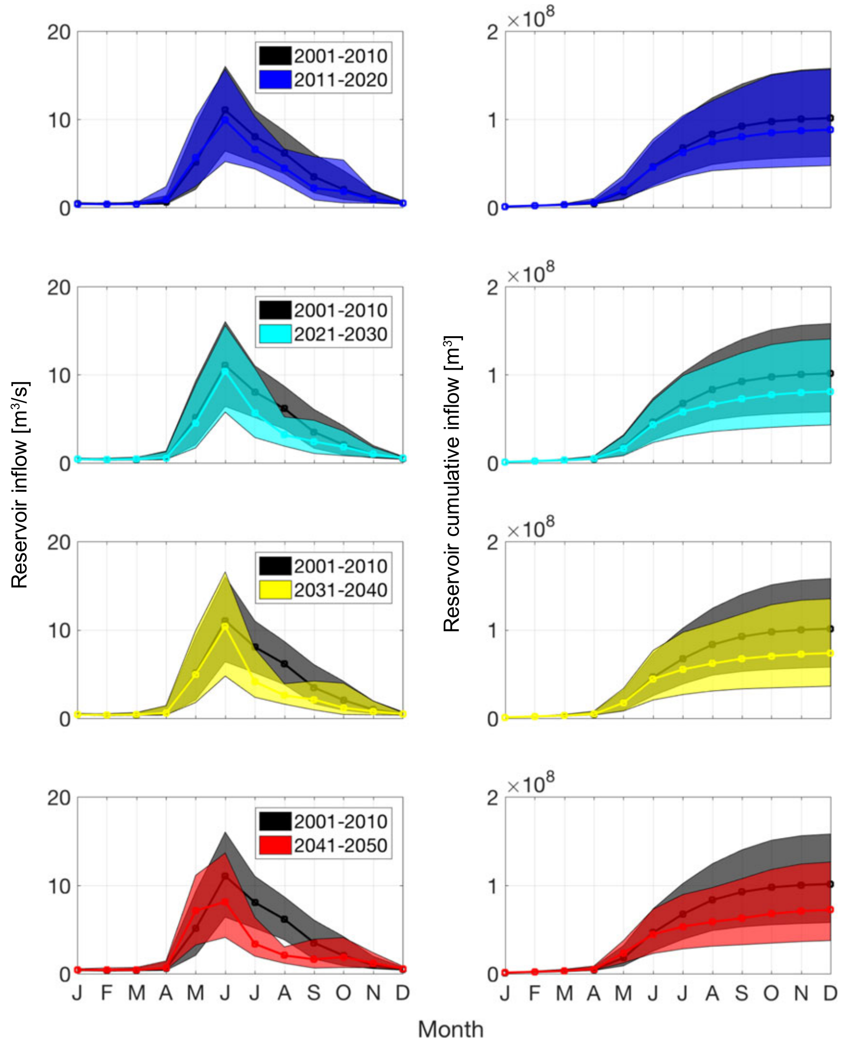

Figure 4. Future reservoir inflow scenarios according to downscaled REMO climate scenario: monthly flow (left panels) and cumulative monthly volume (right panels). Solid dotted lines represent the 50th percentiles computed at a monthly resolution over 100 stochastic simulations; shaded areas represent the inflow between the 10th and 90th percentiles. Different colors represent different decades.

earlier, as suggested by the increase in the percentile spread in April and March (visible in all the decades and especially in the decade 2041 – 2050).

Glacier dynamic simulations are critical to estimate future water availability in high-elevation Alpine catchments. They may be subject to significant uncertainty, descending mostly from the initial glacier thickness distribution and ice melt and accumulation model. Huss et al. (2010), for example, comparatively analyzed the behavior of different glacier models in simulating the evolution of the Rhonegletscher area up to 2100 differentiating between cold and warm scenarios, the latter being a more realistic assumption for the Alpine climate in the medium term. The paper shows that adopting a dynamic glacier model, which redistributes the glacier mass in space by accounting for glacier movements, or a static model can lead to up to 15% differences in glacier area simulations with respect to a benchmark-detailed glacier model and that the uncertainty increases in time with the length of the simulation horizon. Unfortunately, these figures can hardly be exported to other glaciers (Huss et al., 2010), but they suggest that water availability projections in the Mattmark system might be affected by some uncertainty, which is however difficult to precisely assess in magnitude and timing. Our simulations show that the glacier runoff in the Mattmark catchment has already reached its maximum (i.e., peak water) due to climate change warming and declining water availability. This result is in agreement with many other studies conducted both at the local and the global scale. For example,

10.1029/2017WR022289

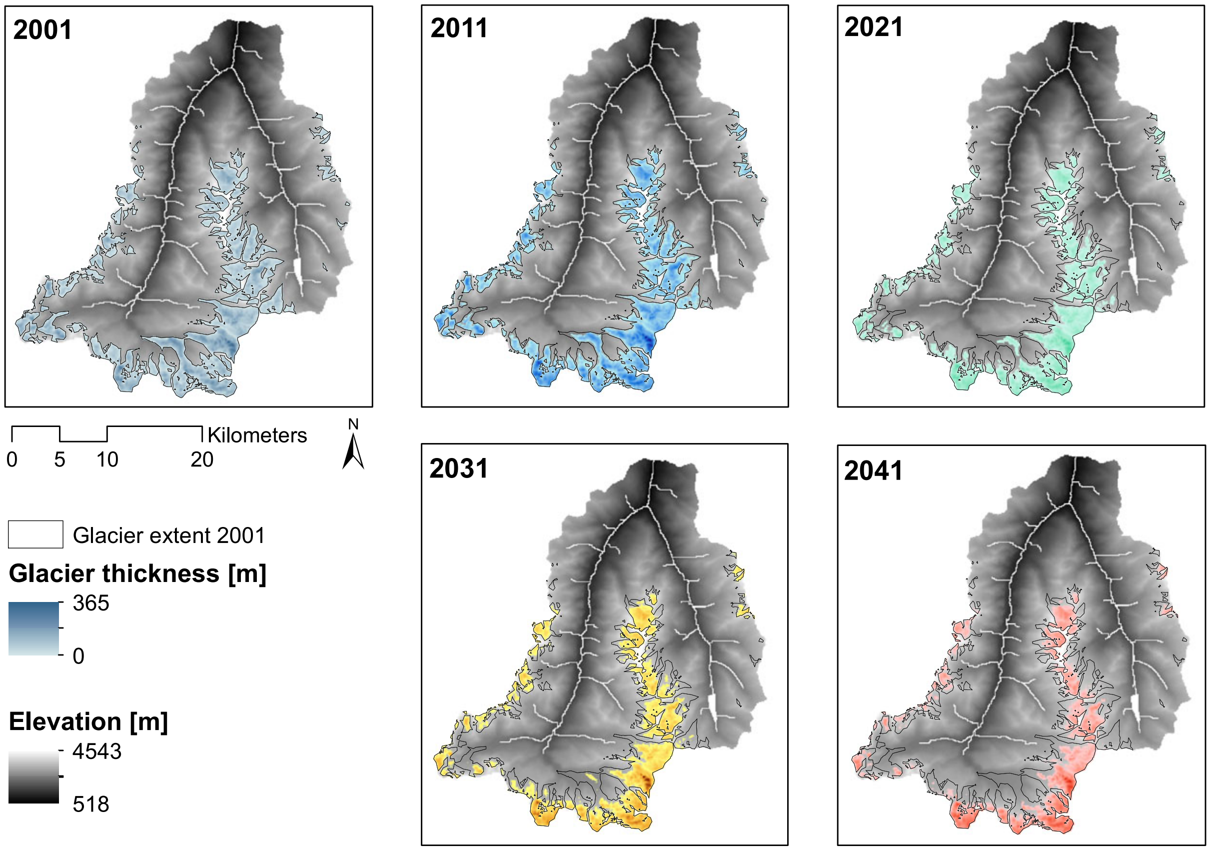

Figure 5. Future evolution of ice distribution over the catchment according to downscaled REMO climate scenario at the beginning of each simulated decade (average over 100 stochastic simulations).

Huss and Hock (2018) show that peak water has been reached in most of the glaciers in the Alps and in the Rhone basin, in particular. Similar results are reported in local studies and specifically in the Mattmark catchment (e.g., Farinotti et al., 2012, 2016; Finger et al., 2012; Schaefli, 2015).

The behavior of the system when baseline-operating rules are combined with future changing scenarios of water availability (CC-BAU) is shown in Figure 6a. This displays the 10th, 50th, and 90th percentiles of the hydropower operation performances measured as mean annual power production and revenue computed over the 100 stochastic realizations for each simulated decade. The distance between each colored area and the dark gray area, representing the performance of the baseline operations, quantifies the impacts due to climate change only (electricity prices in this experiment are the same as in the baseline, see Table 1). Hydropower production and revenue decrease in time as a direct consequence of the reduced annual water availability shown in Figure 4. The production and revenue reductions in the four different decades decrease of about −10% to −27% with respect to the baseline. These figures are similar to those computed by Gaudard et al. (2014) although not directly comparable because of the different time windows adopted in the analysis. Also, Lehner et al. (2005) project a −15% in hydropower potential for the entire Switzerland.

The shaded areas in Figure 6a represent the uncertainty in the estimation of hydropower performance due to natural hydroclimatic variability, as each decade is considered to be stationary when stochastically downscaling the climate change scenarios (see section 2.1.1). We quantify the effect of the natural hydroclimatic variability by computing the percentage variations of the 90th and 10th percentiles with respect to the median. This variability ranges from about ±6% to ±10%. Although the simulations show a clear increase of the adverse climate change impacts in time, the evolution is gradual and tends to stabilize in the period between 2031 and 2050. Partitioning the impacts of climate change and natural hydroclimate variability is not univocal in consecutive decades, as represented by the overlapping areas in Figure 6a. This suggests that considering the inherent stochasticity of future climate scenarios may help identifying more resilient adaptation strategies than when considering a deterministic future climate forcing.

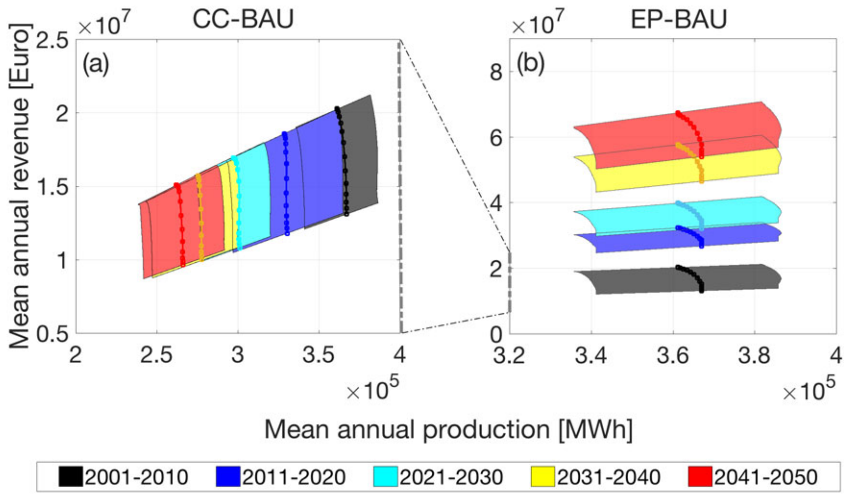

Figure 6. (a) Business-as-usual analysis when considering downscaled REMO climate change scenario (CC-BAU). (b) Business-as-usual analysis when considering electricity price scenario (EP-BAU). Solid dotted lines represent the 50th percentiles of the hydropower operation performance measured as mean annual power production and revenue computed over the 100 stochastic realizations for each simulated decade. Shaded areas represent the range between 10th and 90th percentiles. Different colors represent different decades. The baseline performance is represented in dark gray and it is the same in both panels (a) and (b).

We use future water availability scenarios to estimate new probability functions of the reservoir inflow and design new reservoir operating rules. The performance of these new rules (CC-ADA) are reported in the supporting information. The CC-ADA performance is almost totally overlapping the CC-BAU performance, meaning that there is almost no improvement when changing reservoir operations. In fact, according to the new operating rules, the reservoir release timing changes to accommodate the early snow melt and the inflow reduction in middle and late summer, but the reduction in the annual reservoir inflow volume cannot be compensated by any change in the operations. The electricity production can indeed be increased by maximizing the hydraulic head of the water stored in the reservoir, but this adaptation drives negligible performance improvements (about 2%) if compared to the production loss due to the decrease of the inflow volume. The reservoir inflow-to-storage ratios, computed on the median of the cumulative inflow (solid-dotted lines in the right panels of Figure 4), is about 1 in the baseline, but decreases in the successive decades down to 0.72 (Table 2). This means that, on average, the annual available inflow volume can be easily stored in the reservoir and shifted seasonally to match the variability of electricity prices. The decrease in the inflow-to-storage ratio may have relevant impacts on the interannual operations of the reservoir, which will be possible in the future, while it is hardly the case in the baseline period. This may potentially drive the reservoir management to consider multiple operating objectives, rather than just hydropower, as currently done. Interesting additional objectives could be related to, for example, water conservation and water supply, especially in cases of consecutive dry years.

4.2. Price Change Impact and Adaptation of Hydropower Operations

The price scenarios used in this paper are based on Schlecht and Weigt (2015) and follow the Swiss Energy Strategy 2050 scenarios (Prognos, 2012), the EU Energy Roadmap to 2050 (E3MLab-ICCS, 2013), and the EU Commission's report (European Commission, 2013). They show two main features (see also

Table 2
Inflow-to-Storage Ratio and Reservoir Average Capacity of the Mattmark Reservoir in the Control Period and Future Decades

Decade	50th percentile annual inflow (m^3)	Inflow-to-storage ratio (-)	Daily average inflow (m^3/s)	Reservoir average capacity (months)
2001–2010	101,400,000	1.01	3.22	12.00
2011–2020	88,230,000	0.88	2.80	13.79
2021–2030	81,030,000	0.81	2.57	15.02
2031–2040	73,700,000	0.74	2.34	16.51
2041–2050	72,200,000	0.72	2.29	16.85

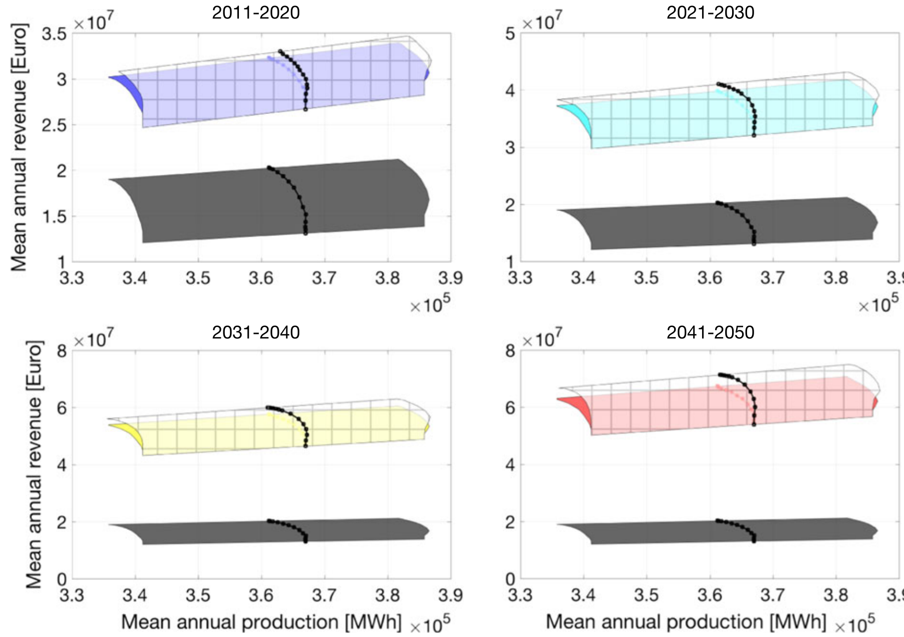

Figure 7. Adaptation analysis when considering electricity price scenario (EP-ADA). Solid dotted lines represent the 50th percentiles of the hydropower operation performance measured as mean annual power production and revenue computed over the 100 stochastic realizations for each simulated decade. Shaded areas represent the range between 10th and 90th percentiles. The dark gray areas represent the baseline performance, colored areas represent the EP-BAU performance, and white areas with square pattern represent the EP-ADA performance. The vertical axis ranges are differently scaled in each panel to highlight the differences between EP-BAU and EP-ADA in each decade.

the supporting information): a general increase in price levels due to increasing fuel and CO_2 emission permit prices and a change in the daily price dynamics due to the increasing share of solar and wind generation. As future price projections strongly depend on the underlying assumptions on fuel and carbon prices, investment costs developments, and demand dynamics, they have a high level of uncertainty. The price projections used within this study are therefore not to be seen as either price forecasts or the most likely price development, but as representative scenarios for two main market trends: increase in the costs for emitting technologies and increase in the share of VRSs.

Figure 6b shows the business-as-usual analysis when considering the price evolution in the next decades (EP-BAU). The hydropower system performance is projected to be steady in terms of electricity production, because the water availability is considered the same as in the baseline in this experiment. Instead, the revenue is increasing because the optimization is driven by the price projections. The average increase in revenue with respect to the baseline is +77% in 2011–2020, +108% in 2021–2030, +155% in 2031–2040, and +187% in 2041–2050. Albeit the revenue increases may seem large, historic market price variations have led to comparable changes in company revenue. For example, Schillinger et al. (2016) show a decrease of revenues for Swiss hydropower plants by 30% to 40% between 2011 and 2014 and potential revenue increases by 20% to 90% for the next decade based on different market price scenarios.

Figure 7 shows the adaptation analysis when considering the price evolution in the next decades (EP-ADA). The difference in overall performance of EP-ADA with respect to EP-BAU is more evident than when considering the adaptation to climate change scenarios (i.e., CC-ADA with respect to CC-BAU shown in the supporting information), because the new operating rules vary the release timing to synchronize to the new price distribution and, in particular, to the new peak prices (see supporting information). Of course, the adaptation of reservoir operations does not affect all the Pareto trade-offs in the same way. The operating rules maximizing electricity production only are totally insensitive to the electricity price. As for the other trade-offs, the higher the relative importance of the revenue maximization objective, the higher the increase in the revenue performance that can be achieved with an adapted operating rule. The increase in revenue maximization of

10.1029/2017WR022289

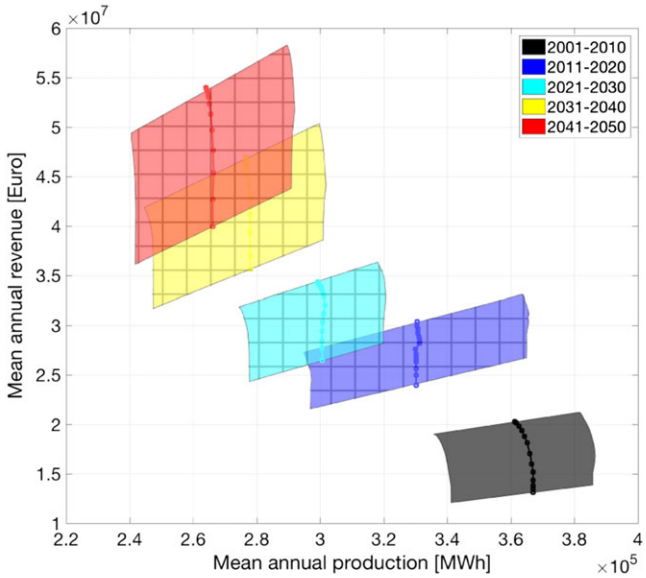

Figure 8. Adaptation analysis when considering both downscaled REMO climate change scenario and electricity price scenario (CC-EP-ADA). Solid dotted lines represent the 50th percentiles of the hydropower operation performances measured as mean annual power production and revenue computed over the 100 stochastic realizations for each simulated decade. Shaded areas with square pattern represent the range between 10th and 90th percentiles. The dark gray areas represent the baseline performance.

EP-ADA rules with respect to EP-BAU rules ranges from +3% in the decade 2011 – 2020 to +7% in the decade 2041 – 2050.

4.3. General Evolution of Future Performance on Hydropower Operations

Figure 8 summarizes the performance obtained with the adaptation analysis considered to take into account both climate change (according to the REMO regional climate model) and electricity prices scenarios, that is, CC-EP-ADA. The figures corresponding to the other two climate change scenarios, that is, ECHAM5r3 and RegCM3, are included in the supporting information.

Even though water availability is decreasing, the increase in electricity price causes the marginal value of turbined water to steadily increase. As already outlined, the portion of the performance space covered in different decades varies depending on the characteristics of the projected changes in the drivers. For instance, the variability in terms of electricity production is the highest in the decade 2011 – 2020 when the variability in the simulated glacier retreat is the highest. Instead, the variability in terms of revenue increases toward the end of the simulated horizon because the price volatility is the highest.

On the basis of the plot, we can summarize the impacts of the different drivers and components analyzed on the two objectives. Natural climate variability, computed on a decade, affects both average production and revenue by a percentage comprised between ±6% and ±9%. There is a small difference of at most 2% between the electricity produced according to different operating rules, that is, by varying the operating rule of the reservoir by accounting for totally electricity-production-driven operations to totally revenue-driven operations. This difference is due to the maximization of the hydraulic head of the water stored in the reservoir (for more details, see Anghileri et al., 2018). However, this difference is negligible if compared with the impacts of both climate change and electricity price change scenarios. The market impacts dominate the overall picture and overcompensate the reduction in average production due to climate change (down to about −27% by 2050). This leads to a general increase of revenues (up to about +181% by 2050). However, when comparing the pure price-driven effect (Figure 7) with the combined effect (Figure 8), we observe a significant reduction in revenue imposed by the reduced production potential. For example, the revenue in 2050 with historic production potential is in the range of 50 to 75 million euro (Figure 7), but in a combined setting this revenue decreases to 36 to 58 million euro (Figure 8).

5. Concluding Remarks

In this paper, we comparatively analyzed how different climate change and energy policies scenarios affect hydropower reservoir systems in the Alps. We assessed the room for adapting reservoir operations to the projected conditions while still achieving the objectives of maximizing revenues and/or production. We built a modeling framework which consists of generation of water availability and electricity price scenarios, hydropower system model, reservoir operations design, and simulation of the effect on electricity production and revenue. We applied the framework to the real-world case study of the Mattmark hydropower reservoir system in Switzerland, which is representative of several other Alpine hydropower systems.

Results show that water availability will significantly reduce due to ice melt and that this will translate in a loss in electricity production down to −27% by 2050. Though this trend is in agreement with other findings of the relevant literature, our study shows, in addition, that the hydropower operations, even if designed to account specifically for the reduced water availability, cannot compensate this loss because they can only redistribute the electricity production within the different seasons, for example, to meet the higher winter demand. This reflects a low adaptive capacity of Alpine hydropower systems to climate change, especially in ice melt-dominated catchments. Even bigger changes are projected for electricity prices, which are likely to heavily impact hydropower operations by substantially increasing the revenue. If the operations are designed specifically to account for the increase in price volatility in the future, more flexible operating rules can be identified, which allow matching the price peaks and might potentially allow for an overall increase in the revenue of the hydropower companies. We did not account, though, for a possible increase in ordinary maintenance costs due to higher flexible operations and for possible technical fitting that might increase the success of adaptation strategies. When combining both impacts, electricity price impacts dominate climate change impacts leading to an overall higher revenue compared with historic conditions of about +181% by 2050.

Our results show that energy policies, for example, CO_2 emission permit price, which are usually not considered in future impact studies, considerably dominate the future price structure and may have significant impact on hydropower operations. These quantitative results are also in line with the perception of hydropower stakeholders. In a survey conducted in 2014, Barry et al. (2015) find that Swiss stakeholders perceive regulatory- and market-related aspects as the most important drivers for hydropower both in the short and long run, while climate-related aspects are more important in the long run. We acknowledge, however, that price evolution on long lead times, for example, decades as in our analysis, is highly uncertain because it strongly depends on political and economic decisions, which are intrinsically difficult to predict. Our analysis should, thus, be seen along this line of reasoning and as a proof-of-concept to explore the sensitivity of Alpine hydropower systems to significant changes of the electricity price structure. Given that the current analysis considered only one possible path for the evolution of energy policies, the results are not to be seen as a reliable estimate of what the future would look like. Further work should be devoted to explore different alternative scenarios for the energy policies in order to properly explore the uncertainty associated to the projections, as much as it is nowadays the usual practice for climate change scenarios. For this reason, we support the idea of relying on energy market models when possible, such as that used in this study, because they can simulate the proper market dynamics in response to scenarios of electricity demands, energy mix, etc. instead of trusting empirical models of price evolution estimated from the historical records. It has to be noted that the price evolution and the climate change projections in our investigations are not considered interdependent. In this respect, while we observed that the available historical data did not exhibit any evidence of dependence with meteorological data, such as temperature (not shown in the paper), we acknowledge that additional effort should be devoted in further studies to interconnect the models used in the scenario generation. This could be achieved, for example, by limiting the water availability for hydropower production in the energy market model or by accounting for climate change induced changes in the electricity demands.

Although based on one hydropower system only, the analysis can be considered representative of many other Alpine systems. Most of these systems show the same setup as Mattmark, with a major reservoir in the upper part of the catchment collecting water mostly from snow and glacier melt and a cascade of power plants exploiting the high-elevation difference and steep slopes which characterize Alpine valleys. The modeling framework can be applied to other large hydropower systems in the Alpine region to estimate the impacts of climate and price change on a regional scale. Future price scenarios will be the same for the entire region as price dynamics are mostly driven by European phenomena rather than regional or local processes: the entire Swiss electricity production (comprising both hydropower and nuclear power) is estimated to be too small to influence prices at the European level (e.g., Banfi & Filippini, 2010; Caro et al., 2011). However, the final impact on hydropower revenue will reflect the combined interaction of changes in price and water availability both in terms of absolute values and timing, as we demonstrated in this paper for the case study of Mattmark reservoir. The water availability change is likely to be case specific as it may depend on the hydroclimatic features of the considered hydropower system, such as the presence of ice-covered areas and the areas of the glaciers, the catchment exposure and elevation (e.g., Huss, 2011; Schaefli, 2015). The extent and timing of glacier retreat together with the variations of annual precipitation volume are particularly important for estimating the impacts on electricity production and revenue. Large hydropower systems are mostly unaffected by changes in the seasonal inflow pattern as the storage capacity can easily accommodate interseasonal water transfers. Hydropower systems where ice melt contribution to total inflow is low (as it is the case for most the hydropower systems located in the southern Alps) might be only relatively affected by climate change (e.g., Anghileri et al., 2011; Gaudard et al., 2014)

Finally, although many hydropower reservoirs in other regions of the world (e.g., Africa, South-East Asia, United States) are operated for other purposes than electricity production, most of the hydropower reservoirs in the Alps are operated as single-purpose reservoirs. Some of them should respect legal restrictions concerning environmental flows to be guaranteed in downstream river reaches. This requirement does not apply to the analyzed case study, the Mattmark hydropower system, but can be easily included in the control problem formulation as an additional constraint. The methodology we propose could be applied also to multipurpose reservoir systems, by including more objectives (not strictly related to hydropower) in the control problem formulation. As a consequence, the scenarios to be considered could include other aspects. For example, if the reservoir were operated for irrigation purposes as well, it would be probably necessary to consider future scenarios of irrigation demand.

Acknowledgments
This research is part of the activities of SCCER-SoE (Swiss Competence Center for Energy Research-Supply of Energy) SCCER-CREST (Swiss Competence Center for Research in Energy, Society and Transition), with the support of Innosuisse. The authors thank Axpo Power AG and Kraftwerke Mattmark AG for the availability of the data used in the analysis. The data used are listed in the references and figures. The data produced in the analysis are available at the following link: https://doi.org/10.3929/ethz-b-000266513.

References

Anghileri, D., Castelletti, A., & Burlando, P. (2018). Alpine hydropower in the decline of the nuclear era: Trade-off between revenue and production in the Swiss Alps. *Journal of Water Resources Planning and Management*, *144*(8), 04018037.
Anghileri, D., Pianosi, F., & Soncini-Sessa, R. (2011). A framework for the quantitative assessment of climate change impacts on water-related activities at the basin scale. *Hydrology and Earth System Sciences*, *15*(6), 2025–2038. https://doi.org/10.5194/hess-15-2025-2011
Aune, F. R., Golombek, R., & Hallre, H. (2015). Phasing out nuclear power in Europe (Working Paper 05/2015). Oslo: Centre for Research on Environmentally friendly Energy (CREE).
Banfi, S., & Filippini, M. (2010). Resource rent taxation and benchmarking—A new perspective for the Swiss hydropower sector. *Energy policy*, *38*(5), 2302–2308.
Barnett, T. P., Adam, J. C., & Lettenmaier, D. P. (2005). Potential impacts of a warming climate on water availability in snow-dominated regions. *Nature*, *438*(7066), 303–309.
Barry, M., Baur, P., Gaudard, L., Giuliani, G., Hediger, W., Romerio, F., et al. (2015). The future of Swiss hydropower—A review on drivers and uncertainties (Working paper): SCCER CREST.
Bartos, M., Chester, M., Johnson, N., Gorman, B., Eisenberg, D., Linkov, I., & Bates, M. (2016). Impacts of rising air temperatures on electric transmission ampacity and peak electricity load in the United States. *Environmental Research Letters*, *11*(11), 114008.
Bates, B., Kundzewicz, Z., Wu, S., & Palutikof, J. (2008). Climate change and water (Technical report). Geneva: IPCC.
Beniston, M. (2003). Climatic change in mountain regions: A review of possible impacts. *Climatic Change*, *59*(1), 5–31. https://doi.org/10.1023/A:1024458411589
Bordoy Molina, R. (2013). Spatiotemporal downscaling of climate scenarios in regions of complex orography (PhD thesis). Zurich, Switzerland: ETH Zurich.
Bordoy Molina, R., & Burlando, P. (2014). Stochastic downscaling of climate model precipitation outputs in orographically complex regions: 2. Downscaling methodology. *Water Resources Research*, *50*, 562–579. https://doi.org/10.1002/wrcr.20443
Brekke, L. D., Maurer, E. P., Anderson, J. D., Dettinger, M. D., Townsley, E. S., Harrison, A., & Pruitt, T. (2009). Assessing reservoir operations risk under climate change. *Water Resources Research*, *45*, W04411. https://doi.org/10.1029/2008WR006941
Caro, G., Cornel, J., Hildmann, M., Daly, D., & Herzog, F. (2011). A quantitative analysis of the electricity market in Switzerland. In *Energy Market (EEM), 2011 8th International Conference on the European* (pp. 923–928). Zagreb, Croatia: IEEE..
Castelletti, A., Pianosi, F., & Soncini-Sessa, R. (2008). Integration, participation and optimal control in water resources planning and management. *Applied Mathematics and Computations*, *206*(1), 21–33. https://doi.org/10.1016/j.amc.2007.09.069
Christenson, M., Manz, H., & Gyalistras, D. (2006). Climate warming impact on degree-days and building energy demand in Switzerland. *Energy Conversion and Management*, *47*(6), 671–686.
Ciarapica, L., & Todini, E. (2002). TOPKAPI: A model for the representation of the rainfall-runoff process at different scales. *Hydrological Processes*, *16*(2), 207–229.
da Graça Carvalho, M. (2012). EU, energy and climate change strategy. *Energy*, *40*(1), 19–22.
Damm, A., Köberl, J., Prettenthaler, F., Rogler, N., & Töglhofer, C. (2017). Impacts of +2 °C global warming on electricity demand in Europe. *Climate Services*, *7*, 12–30.
E3MLab-ICCS (2013). The primes model 2013–2014: Detailed model description (Technical report). Athens: National Technical University of Athens.
European Commission (2013). Trends to 2050 EU energy, transport and GHG emissions reference scenario 2013 (Technical report).
Eurostat (2016). Supply, transformation and consumption of electricity—Annual data [nrg 105a]. (Last checked: 03.06.2017).
Farinotti, D., Pistocchi, A., & Huss, M. (2016). From dwindling ice to headwater lakes: Could dams replace glaciers in the European Alps? *Environmental Research Letters*, *11*(5), 054022.
Farinotti, D., Usselmann, S., Bauder, A., & Funk, M. (2012). Runoff evolution in the Swiss Alps: Projections for selected high-alpine catchments based on ENSEMBLES scenarios. *Hydrological Processes*, *26*(13), 1909–1924. https://doi.org/10.1002/hyp.8276
Fatichi, S., Ivanov, V. Y., Paschalis, A., Peleg, N., Molnar, P., Rimkus, S., et al. (2016). Uncertainty partition challenges the predictability of vital details of climate change. *Earth's Future*, *4*, 240–251. https://doi.org/10.1002/2015EF000336
Fatichi, S., Rimkus, S., Burlando, P., Bordoy, R., & Molnar, P. (2015). High-resolution distributed analysis of climate and anthropogenic changes on the hydrology of an Alpine catchment. *Journal of Hydrology*, *525*, 362–382. https://doi.org/10.1016/j.jhydrol.2015.03.036
Finger, D., Heinrich, G., Gobiet, A., & Bauder, A. (2012). Projections of future water resources and their uncertainty in a glacierized catchment in the Swiss Alps and the subsequent effects on hydropower production during the 21st century. *Water Resources Research*, *48*, W02521. https://doi.org/10.1029/2011WR010733
Fischer, M., Huss, M., Barboux, C., & Hoelzle, M. (2014). The new Swiss glacier inventory SGI2010: Relevance of using high-resolution source data in areas dominated by very small glaciers. *Arctic, Antarctic, and Alpine Research*, *46*(4), 933–945.
François, B., Borga, M., Anquetin, S., Creutin, J. D., Engeland, K., Favre, A. C., et al. (2014). Integrating hydropower and intermittent climate-related renewable energies: A call for hydrology. *Hydrological Process*, *28*(21), 5465–5468.
Gaudard, L., Gabbi, J., Bauder, A., & Romerio, F. (2016). Long-term uncertainty of hydropower revenue due to climate change and electricity prices. *Water Resources Management*, *30*(4), 1325–1343.
Gaudard, L., Romerio, F., Dalla Valle, F., Gorret, R., Maran, S., Ravazzani, G., et al. (2014). Climate change impacts on hydropower in the Swiss and Italian alps. *Science of the Total Environment*, *493*, 1211–1221.
Gobiet, A., Kotlarski, S., Beniston, M., Heinrich, G., Rajczak, J., & Stoffel, M. (2014). 21st century climate change in the European alps—A review. *Science of the Total Environment*, *493*, 1138–1151.
Gurung, A. B., Borsdorf, A., Füreder, L., Kienast, F., Matt, P., Scheidegger, C., et al. (2016). Rethinking pumped storage hydropower in the European alps: A call for new integrated assessment tools to support the energy transition. *Mountain Research and Development*, *36*(2), 222–232.

Haas, R., Panzer, C., Resch, G., Ragwitz, M., Reece, G., & Held, A. (2011). A historical review of promotion strategies for electricity from renewable energy sources in EU countries. *Renewable and Sustainable Energy Reviews*, *15*(2), 1003–1034. https://doi.org/10.1016/j.rser.2010.11.015

Haguma, D., Leconte, R., Côté, P., Krau, S., & Brissette, F. (2014). Optimal hydropower generation under climate change conditions for a northern water resources system. *Water Resources Management*, *28*(13), 4631–4644.

Hamududu, B., & Killingtveit, A. (2012). Assessing climate change impacts on global hydropower. *Energies*, *5*(2), 305–322.

Hänggi, P., & Weingartner, R. (2012). Variations in discharge volumes for hydropower generation in Switzerland. *Water Resources Management*, *26*(5), 1231–1252.

Huss, M. (2011). Present and future contribution of glacier storage change to runoff from macroscale drainage basins in Europe. *Water Resources Research*, *47*, w07511. https://doi.org/10.1029/2010WR010299

Huss, M., & Farinotti, D. (2012). Distributed ice thickness and volume of all glaciers around the globe. *Journal of Geophysical Research*, *117*, F04010. https://doi.org/10.1029/2012JF002523

Huss, M., Farinotti, D., Bauder, A., & Funk, M. (2008). Modelling runoff from highly glacierized alpine drainage basins in a changing climate. *Hydrological Processes*, *22*(19), 3888–3902. https://doi.org/10.1002/hyp.7055

Huss, M., & Hock, R. (2018). Global-scale hydrological response to future glacier mass loss. *Nature Climate Change*, *8*, 135–140.

Huss, M., Jouvet, G., Farinotti, D., & Bauder, A. (2010). Future high-mountain hydrology: A new parameterization of glacier retreat. *Hydrology and Earth System Sciences*, *14*(5), 815–829. https://doi.org/10.5194/hess-14-815-2010

ICLD (2014). Hydropower and dams. World Atlas, International Commission on Large Dams.

IEA (2015a). Tchnology roadmap nuclear energy. International Energy Agency.

IEA (2015b). World energy outlook. International Energy Agency.

Isotta, F. A., Frei, C., Weilguni, V., Perčec Tadić, M., Lassegues, P., Rudolf, B., et al. (2014). The climate of daily precipitation in the alps: Development and analysis of a high-resolution grid dataset from pan-Alpine rain-gauge data. *International Journal of Climatology*, *34*(5), 1657–1675.

Jacob, D. (2001). A note to the simulation of the annual and inter-annual variability of the water budget over the Baltic Sea drainage basin. *Meteorology and Atmospheric Physics*, *77*(1), 61–73. https://doi.org/10.1007/s007030170017

Kern, J. D., Characklis, G. W., Doyle, M. W., Blumsack, S., & Whisnant, R. B. (2011). Influence of deregulated electricity markets on hydropower generation and downstream flow regime. *Journal of Water Resources Planning and Management*, *138*(4), 342–355.

Kern, J. D., Patino-Echeverri, D., & Characklis, G. W. (2014). An integrated reservoir-power system model for evaluating the impacts of wind integration on hydropower resources. *Renewable Energy*, *71*, 553–562.

Ketterer, J. C. (2014). The impact of wind power generation on the electricity price in Germany. *Energy Economics*, *44*, 270–280.

Knutti, R., & Sedláček, J. (2013). Robustness and uncertainties in the new CMIP5 climate model projections. *Nature Climate Change*, *3*(4), 369–373.

Lehner, B., Czisch, G., & Vassolo, S. (2005). The impact of global change on the hydropower potential of Europe: A model-based analysis. *Energy Policy*, *33*(7), 839–855.

Liu, Z., & Todini, E. (2002). Towards a comprehensive physically-based rainfall-runoff model. *Hydrology and Earth System Sciences Discussions*, *6*(5), 859–881.

Magnusson, J., Jonas, T., López-Moreno, I., & Lehning, M. (2010). Snow cover response to climate change in a high alpine and half-glacierized basin in Switzerland. *Hydrology research*, *41*(3-4), 230–240.

Maran, S., Volonterio, M., & Gaudard, L. (2014). Climate change impacts on hydropower in an alpine catchment. *Environmental Science & Policy*, *43*, 15–25. https://doi.org/10.1016/j.envsci.2013.12.001, mountain water governance: Policy implications from the EU ACQWA Project.

Mateus, M. C., & Tullos, D. (2016). Reliability, sensitivity, and vulnerability of reservoir operations under climate change. *Journal of Water Resources Planning and Management*, *143*, 04016085.

Mima, S., & Criqui, P. (2015). The costs of climate change for the European energy system, an assessment with the POLES model. *Environmental Modeling &, Assessment*, *20*(4), 303–319.

Nakicenovic, N., Alcamo, J., Grubler, A., Riahi, K., Roehrl, R. A., Rogner, H. H., & Victor, N. (2000). *Special Report on Emissions Scenarios (SRES), A Special Report of Working Group III of the Intergovernmental Panel on Climate Change*. New York, NY: Cambridge University Press.

Ng, J. Y., Turner, S. W. D., & Galelli, S. (2017). Influence of El Niño Southern Oscillation on global hydropower production. *Environmental Research Letters*, *12*(3), 034010.

Pal, J. S., Giorgi, F., Bi, X., Elguindi, N., Solmon, F., Rauscher, S. A., et al. (2007). Regional climate modeling for the developing world: The ICTP RegCM3 and RegCNET. *Bulletin of the American Meteorological Society*, *88*(9), 1395–1409.

Palmer, M. A., Reidy Liermann, C. A., Nilsson, C., Flörke, M., Alcamo, J., Lake, P. S., & Bond, N. (2008). Climate change and the world's river basins: Anticipating management options. *Frontiers in Ecology and the Environment*, *6*(2), 81–89.

Pechan, A., & Eisenack, K. (2014). The impact of heat waves on electricity spot markets. *Energy Economics*, *43*, 63–71.

Prognos (2012). Die energieperspektiven fur die schweiz bis 2050. Energienachfrage und elektrizitatsangebot in der schweiz 2000-2050 (Technical report).

Ragettli, S., & Pellicciotti, F. (2012). Calibration of a physically based, spatially distributed hydrological model in a glacierized basin: On the use of knowledge from glaciometeorological processes to constrain model parameters. *Water Resources Research*, *48*, W03509. https://doi.org/10.1029/2011WR010559

Roeckner, E., Bäuml, G., Bonaventura, L., Brokopf, R., Esch, M., Giorgetta, M., et al. (2003). The atmospheric general circulation model ECHAM 5. Part I: Model description (Technical report). Hamburg.

Swiss Federal Office of Energy (SFOE) (2012). Erläuternder bericht zur energiestrategie 2050. Swiss Federal Office of Energy.

Swiss Federal Office of Energy (SFOE) (2016). Statistik der wasserkraftanlagen der schweiz. Swiss Federal Office of Energy.

Schaefli, B. (2015). Projecting hydropower production under future climates: A guide for decision-makers and modelers to interpret and design climate change impact assessments. *Wiley Interdisciplinary Reviews: Water*, *2*(4), 271–289. https://doi.org/10.1002/wat2.1083

Schaefli, B., Hingray, B., & Musy, A. (2007). Climate change and hydropower production in the Swiss alps: Quantification of potential impacts and related modelling uncertainties. *Hydrology & Earth System Sciences*, *9*, 95–109.

Schillinger, M., Weigt, H., Schumann, R., & Barry, M. (2016). Hydropower operation in a changing environment, *Energy: Expectations and Uncertainty, 39th IAEE International Conference, Jun 19-22, 2016* (pp. 6–9). Bergen, Norway: International Association for Energy Economics.

Schlecht, I., & Weigt, H. (2014). Swissmod—A model of the swiss electricity market (Discussion paper 2014/01). Basel, Switzerland: University of Basel, Faculty of Business and Economics.

Schlecht, I., & Weigt, H. (2015). Linking Europe—The role of the Swiss electricity transmission grid until 2050. *Swiss Journal of Economics and Statistics*, *2*, 39–79.

Shepherd, S., Bonsall, P., & Harrison, G. (2012). Factors affecting future demand for electric vehicles: A model based study. *Transport Policy*, *20*, 62–74.

Soncini-Sessa, R., Castelletti, A., & Weber, E. (2007). *Integrated and Participatory Water Resources Management. Theory*. Amsterdam, NL: Elsevier.

Steger, C., Kotlarski, S., Jonas, T., & Schär, C. (2013). Alpine snow cover in a changing climate: A regional climate model perspective. *Climate Dynamics*, *41*(3-4), 735–754.

Terrier, S., Jordan, F., Schleiss, A., Haeberli, W., Huggel, C., & Künzler, M. (2011). Optimized and adapted hydropower management considering glacier shrinkage scenarios in the Swiss alps. *Proceedings of International Symposium on Dams and Reservoirs under Changing Challenges, - 79th Annual Meeting of ICOLD, Swiss Committee on Dams, Lucerne, Switzerland* (pp. 497–508). London: CRC Press, Taylor & Francis Group.

Van Vliet, M. T. H., Vögele, S., & Rübbelke, D. (2013). Water constraints on European power supply under climate change: Impacts on electricity prices. *Environmental Research Letters*, *8*(3), 035010.

Van Vuuren, D. P., Edmonds, J., Kainuma, M., Riahi, K., Thomson, A., Hibbard, K., et al. (2011). The representative concentration pathways: An overview. *Climatic Change*, *109*(1-2), 5.

Viviroli, D., Archer, D. R., Buytaert, W., Fowler, H. J., Greenwood, G. B., Hamlet, A. F., et al. (2011). Climate change and mountain water resources: Overview and recommendations for research, management and policy. *Hydrology and Earth System Sciences*, *15*(2), 471–504. https://doi.org/10.5194/hess-15-471-2011

Watts, R. J., Richter, B. D., Opperman, J. J., & Bowmer, K. H. (2011). Dam reoperation in an era of climate change. *Marine and Freshwater Research*, *62*(3), 321–327.

York, R. (2007). Demographic trends and energy consumption in European union nations, 1960–2025. *Social Science Research*, *36*(3), 855–872.

Zemp, M., Haeberli, W., Hoelzle, M., & Paul, F. (2006). Alpine glaciers to disappear within decades? *Geophysical Research Letters*, *33*, L13504. https://doi.org/10.1029/2006GL026319