INTEGRATION OF HYDROPOWER IN A COMPETITIVE POWER MARKET MODEL FOR WATER-ENERGY SCENARIO ANALYSIS

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Abstract

Hydrological systems and power systems are strongly linked: water is needed for most electricity generation technologies, and electricity is required for all stages of water usage. Growing water and energy demands, and potential climate changes suggest this relationship will become more important for the management of both water and energy resources, and should be assessed. We propose a coupled water-energy modeling approach in which a hydrological model imposes the water constraints on the power system model; hydropower generation is bid to the power market based on the hydrological state of the system; and the demands from one system to the other are computed by both models jointly. For this purpose, we develop a bidding strategy for a price-taker hydropower generator based on reservoir volumes and expected electricity prices. The results from the methodology are comparable to those from a dynamic program. The hydropower bidding strategy showed reasonable performance when tested in a simplified model of a competitive power market.

Keywords: water and energy; reservoir operation; modeling

1. Introduction

There is a strong link between hydrology and power systems: water is needed for most electricity generation technologies, while electricity is required for every stage of water usage. Gleick (1993) presents the earliest systematic account of this interdependency, describing the energy requirements for water conveyance, pumping and desalinization; as well as the water requirements for mining of energy resources, for hydropower and for cooling of thermal power plants.

The only large-scale technology widely available for storing electricity is pumped-storage hydropower schemes, which is thus an important water-energy link. There are currently 127000 MW of pumped-storage installed capacity worldwide, and the capacity is expected to increase by 60% during the next four years (IWA, 2010).

There is increasing evidence that climate change will have considerable impacts in hydrological systems through changes in precipitation regimes, and wind and temperature patterns (IPCC, 2007). Variations in the spatio-temporal distribution of precipitation could affect the power system by reducing water availability for cooling systems (Koch and Vogele, 2009) and hydropower generation capacity. Higher temperatures in the Mediterranean region are expected to decrease winter electricity demand, but to increase summer electricity demand by a higher degree (Giannakopoulos et al., 2009), when water resources are already constrained.

These changes combined with higher water and energy demand caused by population growth will add to the challenge of managing water and energy resources. Therefore, the interdependencies between the two systems require a joint analysis of their interaction. A quantitative simulation tool is needed, coupling hydrological and power system models as follows:

1. The hydrological model imposes constraints on the power system with respect to water availability for hydropower generation and power plant cooling.
2. The supply bids of hydropower plants and the supply (demand) bids (offers) of pumped-storage schemes are implemented as functions of the state of the hydrological system; these are then aggregated with bids from other generation technologies to create the aggregated supply curve, which is matched with the aggregated demand to determine the clearing price and the traded amount of electricity in the market. The bidding curves of thermal technologies can also be restricted by the hydrological model if there is insufficient cooling water.
3. The water demand of each power generation technology is incorporated in the hydrological system together with other major water users.
4. The energy demands of water infrastructure, e.g. desalinization plants and large pumping/conveyance schemes are included in the power system model.

This approach allows for the assessment of both systems under future scenarios of climate, and water and energy policies. Moreover, such a tool will simulate the power price, the power generation mix as well as the carbon and water footprint of the produced power for various scenarios. Scenarios include climate change, increased penetration of renewable energy sources, transmission grid infrastructure, etc.

Historically, the electric power system was composed of generation, transmission and (often) distribution facilities that were owned and operated by the same company, which is known as a vertically integrated system (El-Hawary, 2008). Under these conditions, the objective of hydropower optimization was to maximize basin-wide operating efficiency (or minimize overall operation costs) while keeping an adequate security of supply and satisfying power and water constraints (Allen and Bridgeman, 1986; Georgakakos et al., 1997; Yi et al., 2003). Over the last decades, the electrical energy industry in several countries has evolved into a competitive or deregulated system, in which the only objective of generation companies is to maximize profits, regardless of the system's security unless there is an incentive (Liu et al., 2008). It is therefore reasonable to model the power system as a perfect competitive market for the purpose of water-energy studies.

In this work we focus on the development of a bidding strategy for a price-taker hydropower reservoir operating in a competitive power market. Over the past few decades, several methodologies have been used for optimizing reservoir operation and hydropower generation. Dynamic programming is commonly used in the literature for optimization of reservoir operations (Yakowitz, 1982). (Labadie, 2004) presents a state-of-the-art review in optimization of multireservoir system operation.

The problem of maximizing hydropower profits in a competitive market has been solved in several ways. Conejo et al. (2002) use a binary mixed-integer linear programming model to maximize profit from a cascade of 8 price-taking hydropower reservoirs in the day-ahead market, assuming known prices and inflows, and considering head effects, unit performance curves and start-up costs. Fleten and Kristoffersen (2008) forecast day-ahead market prices and inflows with ARMA models and maximize current and expected future (6-day) profits for a two-reservoir cascade through a multi-stage stochastic program. Perez-Diaz et al. (2010) use a dynamic program to determine the optimal unit commitment and another to determine the generation dispatch for a 1-week planning period; assuming known prices and inflows, and considering head effects, friction head losses, tailrace-discharge relations and performance curves for every generating unit.

These approaches have proven useful for detailed real time to short and medium term reservoir optimization. However, in our coupled water-energy simulation scheme we need an optimization approach that a) requires few data; b) can be easily applied to all 200+ reservoirs in the power system; c) can be adapted to changing hydrological conditions; and d) has the flexibility to include increasing degrees of complexity with regards to power plant and environmental constraints.

We present a simple optimization approach based on the derivation of a hydropower bidding strategy as a function of reservoir volumes and average energy prices. We consider head effects, but neglect performance curves and start-up costs due to the difficulty of obtaining realistic data for 200+ reservoirs owned by several generation companies. The approach is illustrated through an example based on the Spanish hydropower system, and can be integrated in a coupled water and energy systems simulator.

The outline of the article is the following: Section 2.1 describes the power market assumed in our model. Section 2.2 shows the proposed bidding strategy and Section 2.3 describes the study case used as example. Results are presented in Section 3 and Discussion and Conclusions are presented in Section 4.

2. Materials and Methods

2.1. Competitive power market model

Competitive power markets are complex structures designed to increase the operational efficiency of power systems while securing an acceptable quality of supply and minimize costs for end users. These structures are typically composed of two markets of electrical energy: the futures market in which participants buy and sell physical or financial products for future delivery; and a pool market which comprises a day-ahead, adjustment and balancing markets (Conejo et al., 2010).

Because our aim is to assess the relation between water and electrical energy systems under different scenarios, we assume that electrical energy will be traded in a single perfectly competitive market, i.e. each supplier or consumer can not affect the price by its individual actions. In competitive markets the price is solely determined by market equilibrium, i.e. demand equals supply. In practical terms, bids to supply submitted by the generators are aggregated in ascending order to create the aggregated supply curve; while offers to buy submitted by consumers are aggregated in descending order to create the demand curve. The intersection between the supply and demand curves represents market equilibrium, determining the market clearing price, the traded amount, and the amounts to sell (buy) by each generator (consumer).

The clearing price π^* can also be determined by solving for the demand and supply functions, $D(\pi)$ and $S(\pi)$ to be equal:

$$D\left(\pi^*\right) = S\left(\pi^*\right) \tag{1}$$

The power market model has been simplified through the following assumptions:

1. Electricity demand is known and inelastic.
2. Fixed and start-up costs are neglected.
3. Marginal costs of production are constant for each generation technology.
4. Transmission losses and congestion are neglected.

To integrate hydropower in the power market model, the optimizing behavior of individual hydropower operators must be expressed in reasonably simple hydropower bidding strategies for the power market, which will depend on the state of the hydrological system. This strategy is presented in Section 2.2.

For illustration purposes we apply this method in the Spanish generation system. Generators are grouped into nine generation technologies, each of them treated as a single generator. The amount and price of the offered hydropower generation is determined by the proposed bidding strategy; for the remaining technologies the offered amount and price is deduced from hourly price and generation per technology data from the Spanish system for the period 15 June 2009 – 21 June 2009. The results are shown in Section 3.2.

2.2. Hydropower bidding strategy

The bidding strategy of a hydropower plant with storage capacity will depend on the current volume, the medium to long term objective volumes, and the expected electricity prices and inflows. In this approach reservoir releases are either maximum or minimum depending on a price threshold π_0, defined as:

$$\pi_0 = \overline{\pi} - a\left(V_t - V_{rc}\right) \tag{2}$$

where $\bar{\pi}$ is the expected electricity price over the planning period (t = 1, 2, 3, …, T), V_t is the volume at the beginning of timestep t, V_{rc} is the desired volume specified by a [monthly] rule curve, and a is a calibration parameter. The releases R_t from $t = t$ to $t = t + 1$, are determined by the current price π_t as

$$R_t = \begin{cases} R_{max} & \text{if } \pi_t \geq \pi_0 \\ R_{min} & \text{if } \pi_t < \pi_0 \end{cases} \tag{3}$$

R_{max} should be set to the maximum turbine flow, while R_{min} should be the minimum ecological flows. The mass balance is kept by Eq. (4), while the generated power over the given time interval is computed from Eq (5).

$$V_t = V_{t-1} + I_{t-1} - R_{t-1} - S_{t-1} \tag{4}$$

$$P_t = \varepsilon \cdot \rho \cdot g \cdot R_t \cdot h_t \cdot \Delta t \tag{5}$$

where V_{t-1}, I_{t-1}, R_{t-1}, and S_{t-1} are the volume, inflow, release, and spill from $t = t - 1$ to $t = t$, respectively. P_t is the power output for the timestep (Wh), ε is a constant efficiency term (-), ρ is the water density ($kg \cdot m^{-3}$), g is the gravitational constant (9.8 $m \cdot s^{-2}$), h is the head loss (m) and Δt is the length of the timestep (hrs). The head h_t is obtained from the level-volume-area curve of the reservoir. In our example, we assume the area (A) is constant, and obtain the head from

$$h_t = \frac{V_t + V_{t-1}}{2 \cdot A} \tag{6}$$

The total revenue from the operation of the power plant is obtained from:

$$\text{Revenue} = \sum_{t=1}^{T} P_t \cdot \pi_t \tag{7}$$

The method above does not consider heads or inflow variation to maximize hydropower generation, and thus provides a sub-optimal policy. To test this method we applied it to a hydropower reservoir in northeastern Spain and compared its results with a dynamic programming solution under perfect foresight of inflow and price variation. The DP setup was given initial and final volumes, as well as the possibility of releasing intermediate values or R between R_{min} and R_{max} that would lead to a state within the state discretization. The results of this comparison are shown in Section 3.1.

2.3. Study case

The Iberian Electricity Market is composed of four markets (MIBEL, 2009):

1. Derivatives market: future electricity production and buying commitments are established.
2. Pool market: composed of a day-ahead market and an intraday adjustment market in which electricity supply and demand for the following day is agreed upon.
3. Ancillary services market: balances the equilibrium between production and consumption in real time.
4. Bilateral trading market: in which two market participants arrange selling and buying for several time horizons.

According to Corchero (2010), at the end of 2009 there were 1169 market participants: 918 producers (out of which 621 correspond the so-called special regime — renewable energies, waste and cogeneration), 192 distributors or suppliers and 59 other agents.

We base our example on data from the day-ahead market, where **77**% of Spain's electricity generation was traded during 2009 (Corchero, 2010). This market is administrated by OMEL, which makes relevant data available through its website, www.omel.es.

Hydropower represents 13% of the total installed capacity of the Spanish generation system. In 2010, hydropower production was 38 001 GWh, covering 14 % of the total Spanish electricity demand (REE, 2010).

3. Results

3.1. Hydropower bidding strategy and DP benchmark

As shown in Figure 1A, the price threshold approach introduced in Section 2.2 lowers the reservoir volume near the beginning of the simulation, while the dynamic programming solution keeps the heads as high as possible throughout the simulation, maximizing generation and revenue. Nevertheless, the revenue difference among the two methods is small and the threshold approach results in a similar release policy. Because the objective of hydropower operators is to maximize profit, this approach will be useful in predicting hydropower generation levels and reservoir releases under different water and energy scenarios.

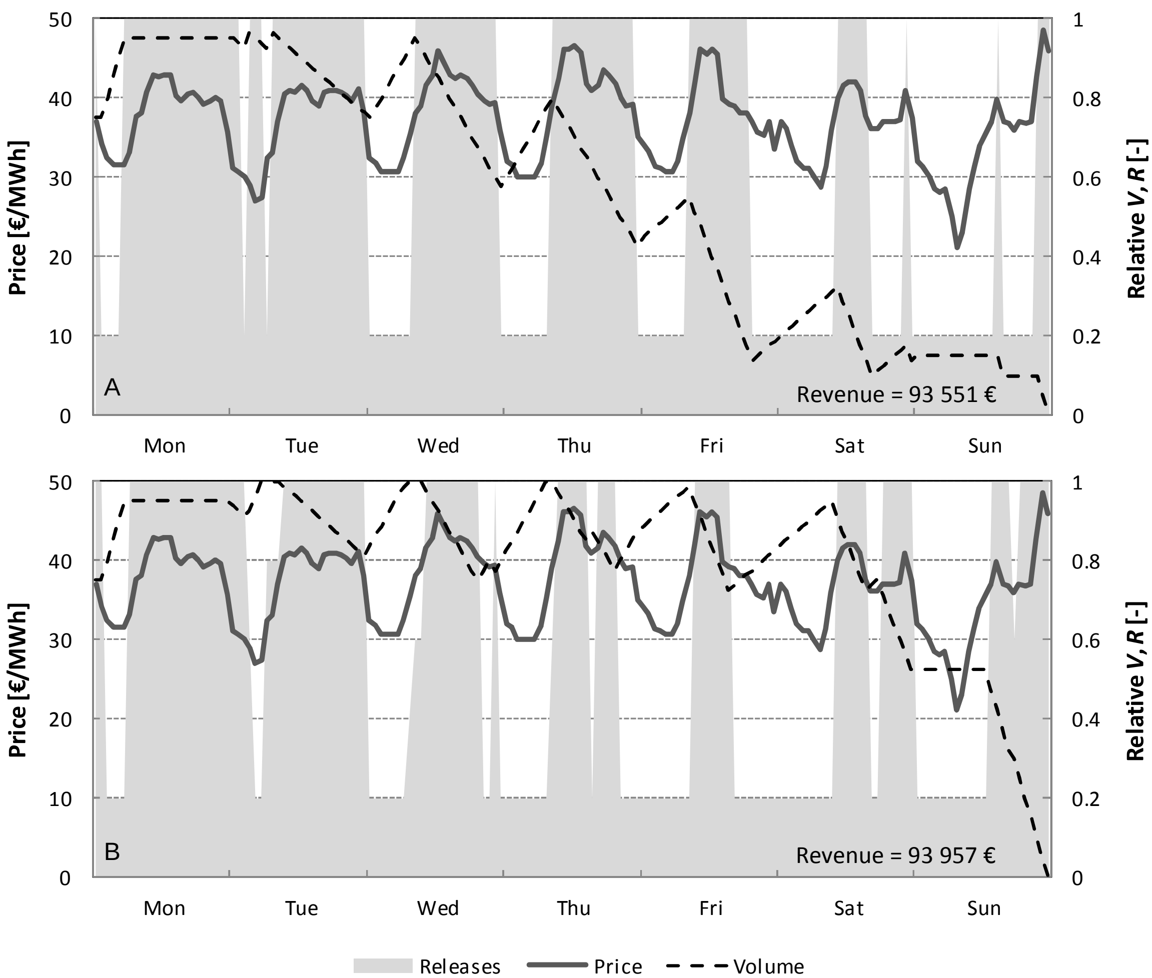

Figure 1. Release, volume and prices for the price threshold approach (A) and the dynamic programming equivalent (B). The volumes are expressed from 0 (lowest observed from both methods) to 1 (dam crest volume); the releases are expressed from 0 (no release) to 1 (maximum release).

Figure 2 shows the hydropower generation using both methods. Again, the difference in generation over time is relatively small.

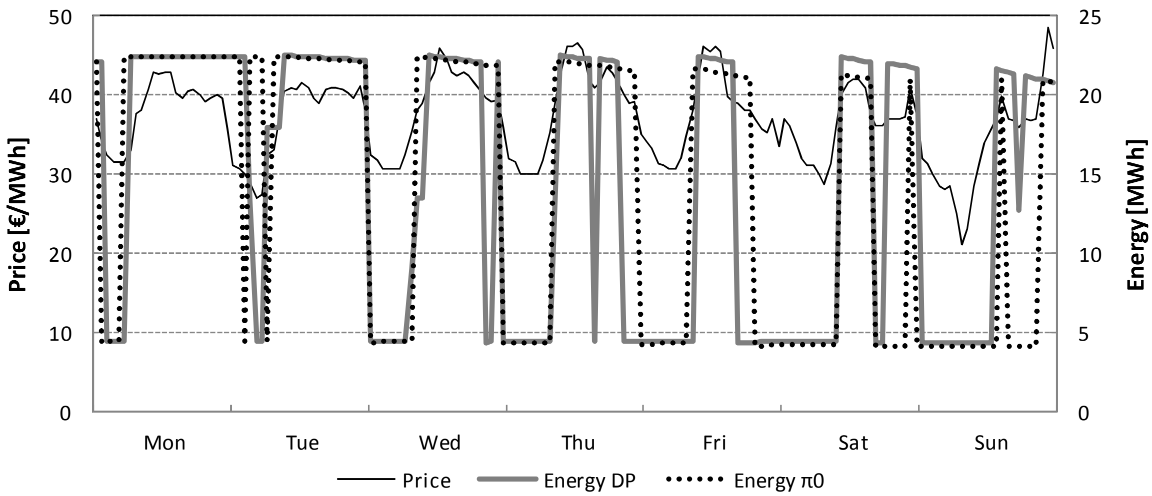

Figure 2. Electricity price and generated energy using the DP and π_0 approaches.

3.2. Application

Following the price threshold approach presented in Section 2.2, the bids to sell hydropower electricity must be placed in two forms: the minimum production (associated with R_{min}) at a zero price to ensure it is sold; and the maximum production (associated with R_{max}) at a price π_0 determined by the current reservoir volume and the expected price. This strategy can be observed in Table 1 for a total hydropower installed capacity of 4000 MW: Hydropower 1 will always be sold, allowing the system to comply with minimum flow requirements; Hydropower 2 will be sold only when the market clearing price is higher or equal than the threshold price ($\pi_t \geq \pi_0$). As explained before, when $\pi_t \geq \pi_0$ all hydropower production (Hydro 1 + Hydro 2) will be sold at the market clearing price π_t. The bid to supply for each generator is shown in Table 1.

Table 1. Generator's bids to supply

Technology	Amount [MW]	Price [€/MWh]
Hydropower 1	1500	0.0
Hydropower 2	4000 – 1500	44.0
Pumped storage	800	45.0
Nuclear	4000	0.0
CCGT	11000	39.5
Thermal	5000	27.0
Spec. Regime* A	6500	22.0
Spec. Regime* B	3500	29.0
Others	6000	23.0

*: Special regime are renewable energies that are sold under special arrangements.

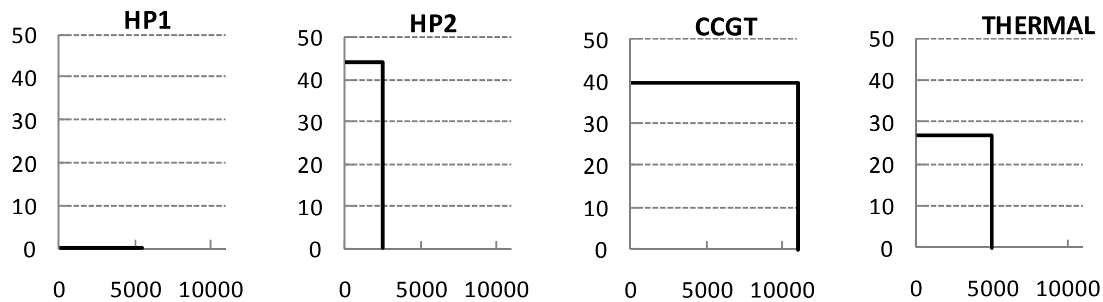

Figure 3. Bids to supply for hydropower, combined cycle gas turbine and thermal (coal and fuel oil)

Figure 3 shows the bids to supply for four out of nine generators considered in this example. In our example, we take the observed hourly production to be the demand for every hour, thus obtaining a set of vertical demand curves. The aggregated supply curve is constructed from the data in Table 1, and the market equilibrium price for every hour of the week is determined by the intersection between the two curves. **Error! Reference source not found.** shows the aggregated supply curve and the demands for an hour with high demand (38 362 MWh, 17 June 2009 11:00) and one with low demand (25 376 MWh, 19 June 2009 03:00).

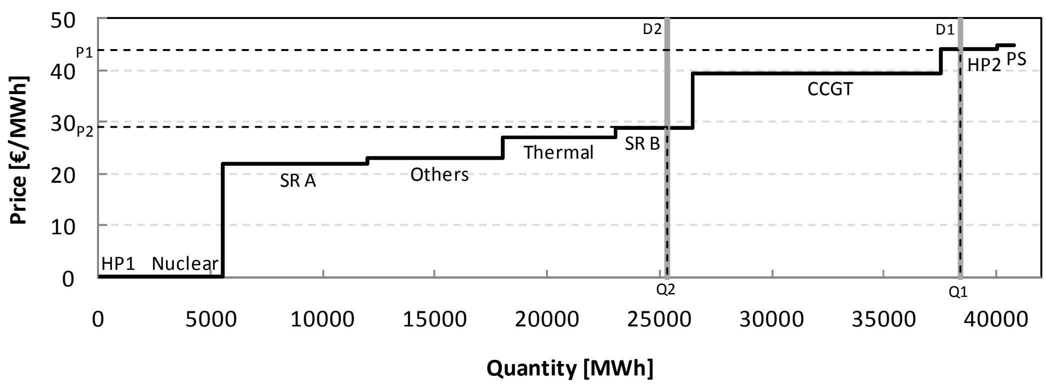

Figure 4. Demand and aggregated supply curves for 17/06/2009 11:00 (D1) and 19/06/2009 03:00 (D2). The results from the market clearance, price (P1, P2) and quantity (Q1, Q2) are shown in the x and y axis.

A demand D1 of 38 362 MWh results in a market clearing price of 44 €/MWh (equal to the price of the marginal technology HP2). A demand D2 of 25 376 MWh results in a market clearing price of 29 €/MWh. The market equilibrium also determines the amount of power sold by each generation technology. In **Error! Reference source not found.** the low demand D2 is covered by the six cheapest techonogolies, namely: HP1, nuclear, SR-B, others, thermal and a fraction of SR-A. The high demand D2 requires additional power from SR-B, CCGT and a fraction of HP2. The water footprint and the carbon footprint of each technology in the energy mix can be calculated from available data on water requirements and CO_2 emissions for each generation technology.

A comparison of observed and calculated equilibrium prices throughout the week is shown in Figure 5.

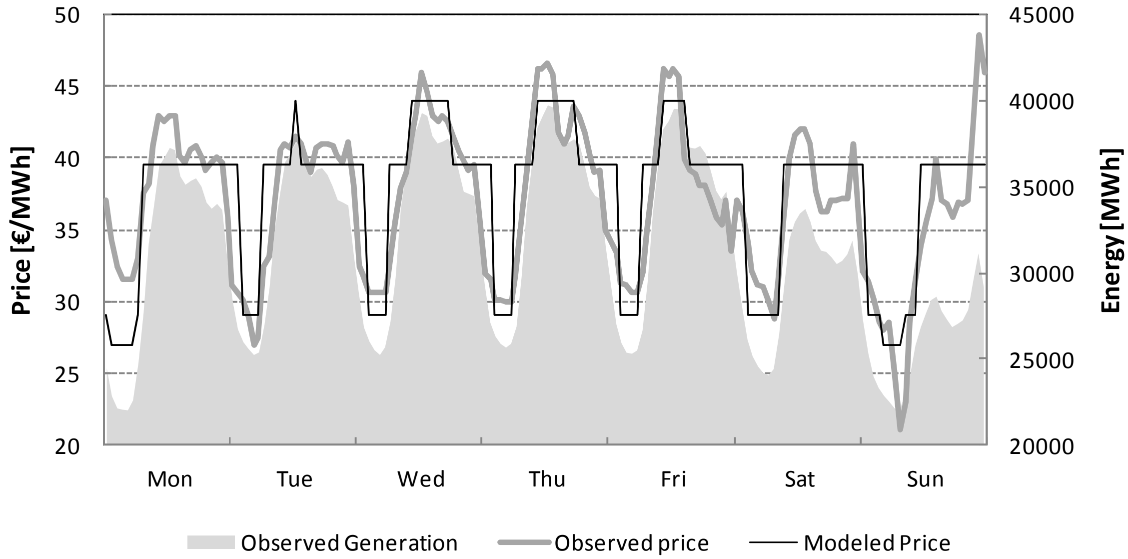

Figure 5. Observed and modeled hourly equilibrium prices from 15 June 2009 00:00 – 21 June 2009 23:00.

4. Discussion and Conclusions

The links between water and energy systems are becoming more important, and a way to assess them is through coupled modeling of the two systems. One of the components of a coupled model is the determination of hydropower generation as a function of reservoir levels and expected electricity prices.

In this paper we present a hydropower bidding strategy for a price-taker generator operating in a competitive electricity market. The reservoir releases are either minimum or maximum depending on a price threshold, which is a function of reservoir volumes and expected prices. Generation increases when the expected price is high and it goes to a minimum when the expected price is low. This translates into a bidding strategy in which the production associated with minimum releases is bid at zero, while the production during maximum releases is bid at the price threshold.

During the period assessed the price threshold provides generation schedules comparable to a dynamic program, which is taken as benchmark. The applicability of the method was tested through an example of the hydropower system in the Spanish portion of the Iberian Elecitricity Market: the demand curve was set to be the observed hourly generation; and the supply curve was created with available capacity and constant marginal prices deduced from the data of generation per technology and price over the period. Market clearing prices were determined by the intersection between the two curves, which resulted in prices similar to those observed during the same period. The methodology requires few data, making it easy to be applied in all reservoirs of interest in the system.

The proposed hydropower bidding strategy is instrumental to our coupled water-energy modeling approach, which will be suitable for scenario assessments:

- Energy policy scenarios can be included in the power market simulation through the bids to supply of each technology. For example, higher penetration of wind energy can be modeled through lower price bids and higher installed wind capacity. The feasibility of storing higher windpower production in pumped storage schemes will depend on the hydrological system and the transmission network.
- Climate change scenarios can be incorporated through modifications in the hydrological system which can lead to changes in the spatio-temporal availability of water resources.
- Each scenario will result in a power price and an energy mix, which will be used to compute the water and the carbon footprint of the power system, and to assess other aspects of the water and energy relationship.

While this approach shows promising results, it has a number of limitations: (1) marginal generation costs for each generation technology are not constant; (2) marginal costs are not equal across all producers using a certain technology, (3) transmission losses and grid congestion are not considered.

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