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Estimation of the Remuneration of Hydro Plants in a Market Environment Using an Iterative Under-relaxation Approach

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Abstract — **One of the challenges that generation companies having hydro stations are facing corresponds to build the most adequate bids to send to day-ahead markets, maximizing their profit and taking into account the expect inflows, market prices and the interdependency between hydro plants in cascades. As a contribution to address this problem, this paper describes a short-term optimization model to build one-week schedules for a set of hydro power plants so that the outputs can be used to bid in the day-ahead market. This model is coordinated with a medium-scale (one year) model that inputs the value of using the water in the short-term problem. The developed model considers the non-linear relationship between the electric power, the net head and the turbine discharge and it takes in consideration pumping as well. The solution approach is based on an under-relaxed iterative procedure based on the algorithm described in [1] and the players are considered as price-takers, so that market prices are input variables. To solve the medium-term problem we propose a similar model that sends information about the final week volumes of each power plant to the short-term problem. On the other hand, we conducted a scenario analysis regarding market prices and inflows to internalize uncertainty. Finally, the model was successfully applied to a real size Portuguese cascade and the paper includes several results to illustrate the application of the developed models.**

Key words – hydro generation, short-term hydro scheduling, medium-term hydro scheduling, pumping, day-ahead market, profit maximization, under-relaxed iterative procedure.

I. INTRODUCTION

During the last years, important changes occurred in the electricity sector, especially with the development of electricity markets. This evolution introduced a trend towards decentralization and liberalization of the sector. These facts place major challenges to all agents, namely to generation companies that are now required to take a number of strategic decisions with different time scales.

Considering the stochastic nature of inflows, as well the interdependency of hydro power plants in a cascade, the management of a power system with a large hydro component is very complex, namely because water has a zero direct generation cost. The development of electricity markets, the possibility of pumping and the non-linear nature of the problem also contribute to increase the complexity of the operation of generation systems having a large hydro component. This is specially important in view of the fact that hydro resource allocation corresponds to one of the most relevant decisions that should be taken by generation companies.

These decisions have different time scales, namely medium-term decisions, as for instance one year for systems having large storage capacity. Afterwards, the medium-term planning will provide inputs to the short-term operation problem, that is, will provide adequate signals in order to achieve satisfactory results when talking about hydraulic coordination.

This paper presents a model to obtain information that can be useful to build the generation bids to send to the day ahead market for a set of connected hydro plants, using the under-relaxed iterative procedure described in [1]. The implemented model considers the non-linear relationship between the electric power, the net head and the turbine discharge, as well as the possibility of pumping.

The main goal of the problem is to determinate the operation schedule of a set of hydro units belonging to the same hydro cascade maximizing the profit that could be obtained in the day-ahead market, while enforcing all constrains as inflows, reservoir levels, water rights or detraction flows for consumption. The model has an hourly base and includes a coordination stage between a short-term model (one week) and a medium-term model (one year). In the short-term, we aim at maximizing the profit taking into account the market prices and the inflows, while the medium-term problem outputs information to the short-term model regarding the best way to allocate the expected inflows over the weeks.

In order to get these objectives, this paper is structured as follows. After this Introduction, Section 2 briefly describes existing approaches in the literature regarding this topic and Section 3 details the implemented model. Section 4 includes results of the application of this approach to a real hydro system based on the Portuguese hydro generation system in order to illustrate the performance of the solution algorithm and the interest of the results for generation companies. Finally, Section 5 reports the main conclusions of the work.

II. STATE OF THE ART

Generation companies have to ensure the best possible operation strategy while trying to maximize their profit. In a competitive environment, they have to build a set of selling bids and communicate them to the day-ahead market operator. But dealing with hydro power plants originates a complex and non-linear problem. There are some strategies to deal with this particular non-linear problem that can be found in literature as for example the following ones:

- considering an average constant net head - this

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approach is not suitable if the reservoirs of hydro power plants have large variation levels, because that would correspond to an unrealistic representation of the reality. In fact, this kind of reservoirs can display large net head variations;
- several publications as [2], [3] and [4] adopt dynamic programming to solve the mentioned non-linear problem. The use of this technique usually leads to large dimension optimization problems if we are dealing with realistic size hydro generation systems;
- the literature on this topic also includes several publications using other techniques as Lagrange relaxation, mixed integer linear programming [5] and meta-heuristics. In this class, there are publications using *Simulated Annealing* [6], *Neural Networks* [7, 8] and *Tabu Search* [9];
- another possibility corresponds to use an iterative procedure in which the net head is assumed constant in each iteration. The value of the net head is successively updated according to the indications in [1, 10, 11].

In the computer application reported in this paper we adopted an iterative approach method to solve the non-linear problem in which the value of the net head is assumed fixed in each iteration. Finally, it should be mentioned that we included in the model the possibility of pumping as a way to increase the realism and applicability of the developed application.

III. MATHEMATICAL FORMULATION

A. Hydro Scheduling Problem (HSP)

The main objective of the Hydro Scheduling Problem (HSP) can be stated as follows - find a feasible operation schedule for a set of hydro stations (including for instance cascades) that maximizes the profit while enforcing a number of constraints. One of the main difficulties when trying to solve this problem corresponds to the non-linear relationship between the discharge volume q, the net head h, and the hydropower $p(q,h)$. This non-linear relationship is illustrated in Figure 1, in which we represent a family of curves of the hydropower depending on the discharge volume, for specified values of the net head.

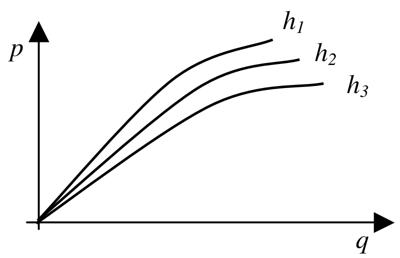

Figure 1 – Family of curves for the hydropower output of an hydro power plant.

Depending on the main characteristics of the hydro system under analysis, this non-linear relation can be neglected or not. For instance, the Portuguese system has several hydro chains with small reservoirs in which the net head variations can be large. In this case, the mentioned non-linear relation should be retained and addressed in the model in order to obtain accurate results.

In this work we used the under-relaxed iterative procedure originally described in [1] to tackle this non-linear nature. This approach solves the non-linear problem using an iterative procedure in which the net head is considered constant in each iteration. Its value is successively updated so that the next iteration uses a refreshed value for the net head. As the net head of each hydro station is a variable of the problem, depending on the reservoir levels at each scheduling period, it is impossible to determinate *a priori* their optimal values. For this reason, the approach described in [1] follows the iterative procedure detailed below. Let us consider the reservoir *i*, and the scheduling period *k*. The iterative algorithm would then evolve as follows:

Step 1 – Iteration *it*=1. Initialize the net head h_{ik}^{it},

Step 2 – Build the simplified expression for $\phi_{ik}^{it}(q_{ik})$,

Step 3 – Solve the simplified HSP problem using $p_{ik} = \phi_{ik}^{it}(q_{ik})$,

Step 4 – Update h_{ik}^{it}. If convergence is not reached, increase the iteration counter *it* and return to Step 2.

In this scheme, the variables have the following meaning:
- h_{ik}^{it} is the net head of reservoir i, in period k;
- q_{ik} represents the discharge volume;
- p_{ik} is the power output;
- $\phi_{ik}^{it}(q_{ik})$ represents the simplified linear function relating the power output and the discharge volume for a specific value of the net head.

A detailed description of this iterative algorithm is provided in the next paragraphs.

Step 1

In order to simplify the problem, let us assume that the tailwater level of the downstream reservoir is constant. Under this condition, the net head h_{ik} can be calculated as a function of the reservoir storage v_{ik} using (1).

$$h_{ik} = \rho(v_{ik}) \tag{1}$$

To initialize the iterative process, we should select the value of the net head to use in the first iteration. This value can be selected using the approach proposed in [1]. This means assuming a linear trajectory of the stored water by joining the initial and the final stored water along the temporal scheduling horizon.

Step 2

In this step we build the simplified HSP linear function using the current values of the net heads for each hydro station. However, considering that the head is constant is not enough in order to obtain a linear function. The relation between the power output and the discharge volume is also non-linear because of the head loss as indicated by expression (2)

$$p_{ik} = k \cdot q_{ik} \cdot (h_{ik} - \beta \cdot q_{ik}^2) \tag{2}$$

In this expression:

- k is a constant related with the efficiency;
- $\beta = \dfrac{\Delta hn}{qn^2}$ is the head loss coefficient;
- Δhn is the nominal head loss;
- qn represents the nominal discharge flow.

So, to solve this problem, we consider that the head loss is constant, and that it corresponds to the maximum value of the discharge volume, that is, we assume that $\Delta h_o = \beta \cdot q^{max}$. This means that the power output of the hydro station i in the scheduling period k is now given by expression (3).

$$p_{ik} = k \cdot q_{ik} \cdot (h_{ik} - \Delta h_0) \tag{3}$$

Given the characteristics of the hydro system, this approximation is valid because it is operating close to its maximum discharge area Δq as illustrated in Figure 2.

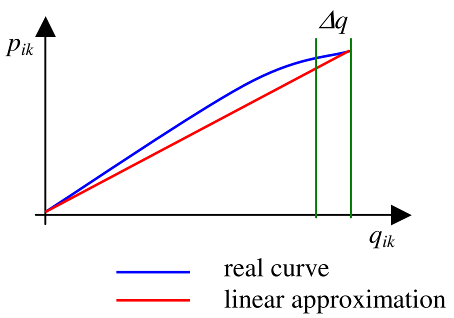

Figure 2 – Power output approximation for a given net head.

Step 3

After the linear function (3) is built, the simplified HSP problem for a constant net head is solved using a linear programming method. One advantage of using this iterative procedure comes from the fact that it is possible to include non-linear constraints as (10), given that the value of the net head is successively update in each iteration.

Step 4

In this step the model checks whether converge was reached, or not. If not, the input data for next iteration is prepared. As it is referred in [1], the values of the volume obtained in the last iteration could provide new values to the reservoir levels to be used in the next iteration. However, to avoid undesirable non convergence of the algorithm the authors in [1] proposed to update the net head h_{ik}^{it+1} also taking into account information from the previous iteration. In order to implement this strategy, they defined a relaxation parameter α>0 and the new value for the updated net head can be obtained using expression (4).

$$h_{ik}^{it+1} = \rho_i \left(v_{ik}^{it+1} \right) = \rho_i \left(v_{ik}^{it} + \alpha \cdot \left[v_{ik} - v_{ik}^{it} \right] \right) \tag{4}$$

Unfortunately, the definition of the value of the parameter α depends on the characteristics of the hydro power plants. This means that the use of this parameter becomes strongly case-dependent.

Finally, it is necessary to check if convergence has been reached or not. For that, we computed the relative error of the reservoir levels of each hydro station in each scheduling period, using expression (5).

$$\varepsilon = \frac{\left(v_{ik} - v_{ik}^{it} \right)}{v_{ik}^{it}} \tag{5}$$

This iterative procedure stops if the largest relative mismatch for the storage capacity, between two consecutive iterations, is smaller than the tolerance value specified for ε. In this work we used 0,1 % for this tolerance value.

B. Short-Term Model Formulation

The HSP short-term model aims at maximizing the profit of a set of hydro power plants operating in an electricity market environment. In the implemented approach we considered a time scale of a week with an hourly discretization. The formulation of this problem for a given iteration of the previous iterative algorithm, that is, for a constant value of the net head, corresponds to (6) to (14).

$$max \sum_{i=1}^{I} \sum_{k=1}^{K} (\pi_k \cdot Pt_{ik}) - (\pi_k \cdot Pb_{ik}) - (ps \cdot s_{ik}) \tag{6}$$

subj.

$$\begin{aligned} v_{ik} = {} & v_{i(k-1)} + a_{ik} - qt_{ik} - s_{ik} + qb_{ik} + \\ & + \sum_{m \in M_i}^{L} \left(qt_{m(k-\phi_m)} + s_{m(k-\lambda_m)} - qb_{m(k-\omega_m)} \right) \end{aligned} \tag{7}$$

$$vol_{ik}^{l\,min} \le qt_{ik} + s_{ik} - qb_{ik} \le vol_{ik}^{l\,max} \tag{8}$$

$$v_i^{min} \le v_{ik} \le v_i^{max} \tag{9}$$

$$qt_i^{min} \le qt_{ik} \le min \left(qt_i^{max}, qtn_i \cdot \sqrt{\frac{h_{ik}}{htn_i}} \right) \tag{10}$$

$$qb_i^{min} \le qb_{ik} \le min \left(qb_i^{max}, qbn_i - \delta_i \cdot (h_{ik} - hbn_i) \right) \tag{11}$$

$$0 \le s_{ik} \le \infty \tag{12}$$

$$v_{ik} = vol_{iK} \tag{13}$$

$$i = 1,...,I ; k = 1,...,K ; m = 1,...,L \tag{14}$$

In this formulation:

- I - number of reservoirs;
- K - number of scheduling time periods;
- L - number of upstream reservoirs;

- π_k - market price in hour k;
- Pt_{ik} - power output in reservoir i, hour k;
- Pb_{ik} - pumping power in reservoir i, hour;
- ps - penalty factor for spills;
- s_{ik} - spill of reservoir i, in hour k;
- v_{ik} - volume of reservoir i, in hour k;
- a_{ik} - inflow of reservoir i, in hour k;
- qb_{ik} - pumping volume of reservoir i, in hour k;
- qt_{ik} - discharge volume of reservoir i, in hour k;
- M_i - set of upstream reservoirs of reservoir i;
- ϕ_m - delay of turbine discharge volumes;
- λ_m - delay of spill volumes;
- ω_m - delay of pumping volumes;
- $vol_i^{l\,min}, vol_i^{l\,max}$ - minimum and maximum launch volumes of reservoir i;
- v_i^{min}, v_i^{max} - level volume limits of reservoir i;
- qt_i^{min}, qt_i^{max} - turbine discharge limits of reservoir i;
- qb_i^{min}, qb_i^{max} - pumping volumes limits of reservoir i;
- qtn_i - nominal turbine discharge volume of reservoir i;
- qbn_i - nominal pumping volume of reservoir i;
- htn_i - nominal turbine head of reservoir i;
- hbn_i - nominal pumping head of reservoir i;
- δ_i - pumping coefficient of reservoir i;
- vol_{iK} - volume level of reservoir i in the last scheduling period, K.

C. Medium-Term Model

In order to input meaningful information regarding the use of water resources along the year, we also implemented a medium-term scheduling model. It has a similar formulation regarding the one adopted for the short-term, but the time discretization corresponds now to a week. In this case, it aims at obtaining the allocation of the water resources to each week, according to the expected input price markets along the year.

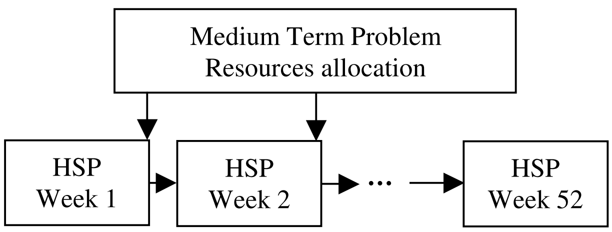

Figure 3 – Short-term / medium-term coordination.

This approach is important for generation companies having power plants with large storage capacities. This coordination strategy is illustrated in Figure 3. As a result of running this model, one can obtain the initial and final volumes of the hydro reservoirs as well as the value of using the water in each week. The weekly values of using the water correspond to the dual variables of the water balance equations established in the model for each week. In any case, it should be mentioned that the possibility of pumping is typically not considered in the medium-term model because we are interested in allocating the inflows to each week and to not to detail the hourly operation of the system.

This means we can then run the weekly short-term models in two ways. One can include the information about the initial and final volumes of each hydro reservoir in constraints (13). The second approach would correspond to use the value of the water obtained for the week under analysis in the medium-term model in the objective function of the short-term model. This would correspond to the approach adopted in reference [12]. In this paper, it is used the objective function (15) aiming at maximizing the addition of two terms. The first one corresponds to product of the electricity market prices by the output power in each hourly period. The second one reflects the value of using the water, Ψ, multiplied by the final volume in the last hour of the week. As an example, if the value of Ψ obtained for week i in the medium-term model is large, the short-term model will tend to use more water as a way to maximize the objective function (15).

$$F = max\left(\sum_{i=1}^{I} \sum_{k=1}^{K} \pi_{ik}\, p_{ik} + \sum_{i=1} \Psi_i(\, v_{ik}\,) \right) \tag{15}$$

During this research we also conducted some experiences in order to compare the results that could be obtained using these two approaches. We concluded that they were comparable meaning that it is possible to link the short-term formulation with other more powerful medium-term models to obtain more accurately the value of using the water.

If the companies have small reservoirs, or have no interest in building a long time allocation of their water resources, it is possible to use the implemented model considering only the water value obtained for a few weeks forward.

D. Dealing with uncertainty

When considering a day-ahead time horizon, water inflows and market prices can be estimated with good accuracy. However, if we consider a time horizon of one year, forecasting exercises are far more difficulty. For this reason, it is important to incorporate uncertainty in this problem. In this approach, we treated uncertainty by analysing different scenarios for inflows and market prices, which can be considered in the input data. At the end, we can compute average values for several variables characterizing the operation of the hydro system as it will be illustrated in Section 4.

IV. CASE STUDY

A. Data of the hydro system

The approach described in this paper was tested using a real sized Portuguese river basin. The application was developed in MatLab in a 1.8 MHz PC with 512 Mb RAM. Table 1 details the data of the 8 hydro plants and Figure 4 illustrates the structure of the hydro basin. The inflows of hydro power plants F, G and H are typically large, while the inflows of the remaining hydro stations are more reduced.

Table 1 – Hydro plants characteristics.

Reservoir	Vol. max (hm^3)	Vol. min (hm^3)	qtn (m^3/s)	qbn (m^3/s)	htn (m)
A	31	25	120		30
B	83	71	500		2
C	216	156	210	162	116
D	97	85	550		30
E	95	82	744		27
F	148	132	705		33
G	106	84	320	251	50
H	110	94	750		11

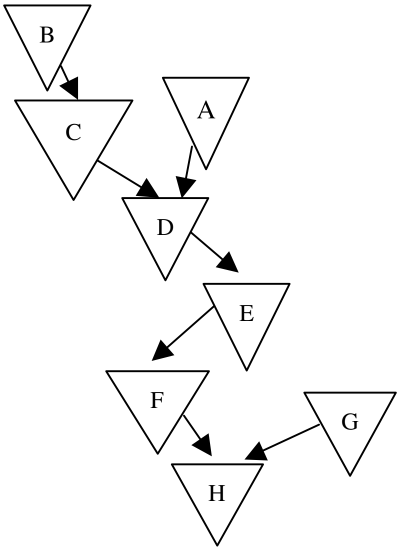

Figure 4 – Hydro chain cascade.

B. Short-term analysis

In the work reported in this paper we ran the medium-term model established for a complete year, that is, we used the initial and final volumes obtained for a complete year leading to the formulation (6) to (14). In the first place, we will present the results obtained for the HSP short-term optimization for a particular week of the year. Regarding this problem, Figure 5 presents the results that were obtained for a week. These results indicate how the hydro stations should be scheduled in order to fulfill the objective of maximizing the profit and the chart also indicates the evolution use for the price of electricity in the market. Units F and H are a good example of run-river units and the schedules of the other ones tend to follow the periods in which market prices are larger.

From a computational point of view, the iterative process converged in a reduced number of iterations and the results display a very good quality contributing to improve the operational results that could be obtained by the generation company.

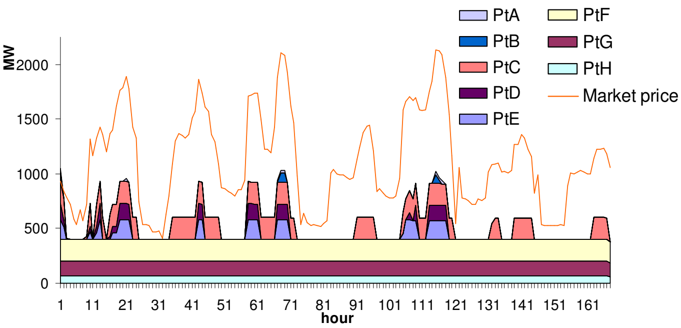

Figure 5 – Results for the generated power of the cascade.

Figure 6 shows the results obtained for pumping. As we can see, the hydro station G has no pumping consumption, because it has large inflows during the whole week. Differently, the hydro station C typically has reduced inflows. As a result its consumption for pumping is large and this coincides with the periods in which market electricity prices are more reduced.

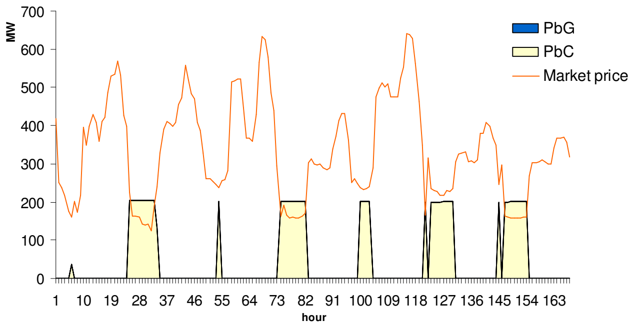

Figure 6 – Results for the pumping power of the cascade.

Finally, the convergence error computed using expression (5) is shown in Figure 7. As we can see, convergence was reached in 4 iterations with an execution time of 30 seconds. The value of the parameter α used in this simulation was 0.9.

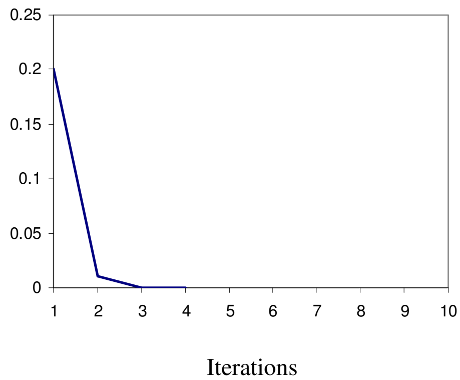

Figure 7 – Evolution of the convergence error.

C. Short-term/Medium-term coordination

As mentioned in the beginning of Section IV.B, the short-term results were obtained using the initial and final volumes coming from the medium-term model. However, the medium-term also outputs the value of using the water for each week of the period. The value for each hydro plant corresponds to the dual variable of the corresponding balance equation. As an example, Figure 8 presents the water value for one of the hydro power plants of the cascade in Figure 4 along the year.

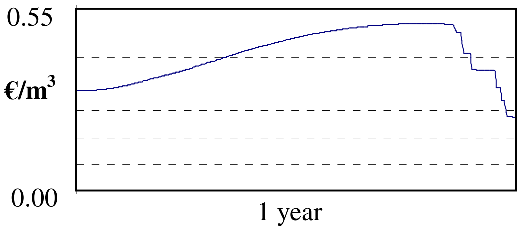

Figure 8 – Water value of one hydro station of the cascade.

D. Estimate of the operation profit

To take the uncertainty into account, we considered and analyzed 10 scenarios of inflows and 3 scenarios of electricity prices (an high, medium and low price scenario). This means they were analysed 30 inflow/price scenarios from which we computed average values for several variables characterizing the operation of this hydro system.

Table 2 presents the results of these simulations, namely the annual average values for the generation, the pumping cost, the generation value, the cost of pumping and the final net benefit. This benefit corresponds to the difference between the average values of the annual value of generation and the annual cost of pumping.

Table 2 – Average annual results obtained.

Average Annual Generation	GWh	2,160
Av. Annual Pumping Cons.	GWh	868
Av. Annual Value of Generation	k€	83,994
Av. Annual Cost of Pumping	k€	15,082
Average Annual Net Benefit	k€	68,912
Processing time	h	11.0

V. CONCLUSIONS

This paper presents a short-term optimization model to help hydro generation companies to obtain a good scheduling for their units so that they can prepare bids to communicate to a pool based day-ahead electricity market. The developed approach solves the non-linear optimization problem using an iterative under-relaxation approach, considering pumping, the interdependency of units, reservoir constrains and electricity prices. The hydro power plants were supposed to be price takers. This paper also details a medium-term scheduling model to obtain medium-term schedules for the use of the water that can, afterwards, be used as input to the short-term problems.

Finally, the results obtained for a real system based on the Portuguese generation system were very satisfactory namely in terms of improving the operational profit regarding the values that were traditionally obtained.

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