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Comparison between piecewise linear and non-linear approximations applied to the disaggregation of hydraulic generation in long-term operation planning

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ABSTRACT

This paper presents a comparison of two proposed approaches to model the hydropower production functions (HPF) applied to long-term operation planning problems. The first approach consists of a non-linear approximation that uses a sigmoid function, and the second approach consists of a piecewise linear approximation. In this study, we aimed to disaggregate the target for each subsystem into individualized generation targets. A study case using the Brazilian power system is presented to evaluate both methodologies. The results show that the piecewise linear approach presents a good approximation with a considerably lower computational time.

Introduction

The growth of electrical power systems in terms of size and complexity due to the increasing demand for electricity and the need for greater reliability, in addition to the need for cost reduction, have resulted in an ever-greater interconnection among existing power generating systems. Interconnected systems are advantageous because they allow for energy gains by coordinating hydrothermal operation, which ensures better hydrological use among existing basins. Due to the increase of these interconnections, the operation of the coordinated system is very complex, and detailed planning of its operating conditions is required for the achieved performance to be compatible with the quality and security requirements.

In this context, the primary objective of long-term hydrothermal system operation planning is to meet the estimated demand of electrical power for a period of up to five years with discretization on a monthly basis and while considering the uncertainties of availability and the generation costs [18]. Thus, to solve this problem, the optimal amount of hydro and thermal power generation for all planning stages must be determined to reduce the expected total operating costs over the study period and to consider the inflows' stochasticity.

The three main characteristics of this problem are (i) the stochasticity related to the uncertainty of the future inflows to the reservoirs; (ii) the spatial coupling in which the operation of a hydroelectric power plant with upstream reservoirs impacts the operation of the downstream hydroelectric power plants; and (iii) the temporal coupling, which is related to the impacts of the present generation decisions regarding the operating costs of the next stages [18].

One possible method for coping with this problem is to use Dynamic Programming (DP) to solve the Long-Term Operation Planning (LTOP) problem. Essentially, DP is a sequential decision-making process that follows "Bellman's Principle of Optimality" [3]. The use of DP requires a high level of computational effort due to the number of states. To avoid this problem, models that are based on the aggregation of hydroelectric power plants in equivalent energy systems are used to reduce the search space and the number of evaluated operational states [1].

Several studies have used dynamic programming techniques with reservoir aggregation to perform LTOP [14,15,19,5].

The solution of this problem is generally obtained using the following steps. (i) Operation Policy: A set of hydrological scenarios

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that are used in the construction of the expected cost to-go functions (ECF) for each study stage, [4]. (ii) Simulating the Operation: A set of hydrological scenarios that is used to reproduce the system operation using the ECFs that were created in the previous step. In this step, the solved optimization problems include a monthly basis, and the energy stored at the end of each stage is used as the initial stored energy for the following stage. The aim of this step is to define the values of the decision variables, including the Energy Generation, Energy Exchanges, Deficit, and Stored Energy variables. This step is performed by considering aggregated reservoirs. (iii) Individual Targets: In this step, the individual generation target, or the amount each unit must generate to follow the targets previously obtained in step (ii), is defined. One example is the Brazilian official chain of models [11].

The present study proposes two different approaches for approximating hydroelectric production functions in the simulation of operation and in individual hydro plants generation targets steps. The first approach uses a non-linear approximation with a sigmoidal function and the second approach uses a piecewise linear approximation. The impacts of both methodologies in long-term operation planning are evaluated. In addition, a case study with the Brazilian Interconnected System is presented to compare the results obtained by both approaches.

The paper is outlined as follows: Section 'General formulation' presents the general formulation of the problem. In Section 'Proposed methodologies', the proposed methodologies for approximating the hydro production functions are formulated. Section 'Results' details the results by considering a real system as a case study. Finally, the conclusions are presented in Section 'Conclusions'.

General formulation

The long-term hydrothermal operation-planning problem consists of minimizing the objective function that is composed of the expected operation costs that are subjected to the following constraints: (i) Water balance equation; (ii) Load balance equation; (iii) maximum hydraulic generation; (iv) expected cost-to-go functions and (iv) operation limits of variables [16].

Thus, the objective function given by Eq. (1) is to minimize the sum of the immediate operating costs of each month (thermal generation and deficits) and the expected future costs.

$$z_t = min\left\{E\left[\sum_{i=1}^{NSIS}\left[\sum_{w=1}^{NTER_i}\psi_{T_{i,t,w}} \times g_{T_{i,w,t}} + \psi_{D_i} \times def_{t,i}\right] + \alpha_{t+1}\right]\right\} \tag{1}$$

Here, $NSIS$ represents the number of subsystems; $NTER_i$ is the number of thermal generators of the each subsystem i; $\psi_{T_{i,t,w}}$ is the generation cost associated with the thermoelectric unit w (\$/MWmonth); $g_{T_{i,w,t}}$ represents the thermal generation of each unit at stage t (MWmonth); ψ_{D_i} represents the costs of the deficit for each subsystem (\$/MWmonth); $def_{t,i}$ represents the load shedding (MWmonth) and α_{t+1} is the expected future cost that is associated with the following stages.

The water balance constraints that represent the dynamics of the hydroelectric reservoirs between two stages are represented by Eq. (2).

$$\begin{aligned} &va_{j,t+1} + vt_{j,t} + vv_{j,t} - \sum_{m=1}^{NM_j}(vt_{m,t} + vv_{m,t}) \\ &\quad = AFL_{j,t} \times FATOR_t + VA_{j,t} - VEVAP_{j,t} \end{aligned} \tag{2}$$

where $va_{j,t+1}$ is the volume stored at the hydraulic power plant j at instant t, which belongs to subsystem i (hm^3); $vv_{j,t}$ is the spilled volume (hm^3); $vt_{j,t}$ is the turbined volume (hm^3); $AFL_{j,t}$ represents the incremental inflow of each hydroelectric power plant (hm^3); NM_j is the set of hydroelectric power plants upstream a given power plant j, $VA_{j,t}$ is the volume stored in the beginning of stage t and $VEVAP_{j,t}$ is the evaporated volume (hm^3).

The constraint that represents the load balance is depicted in Eq. (3) and considers the sum of thermal and hydroelectric generations, the deficits and also accounts the energy exchange between subsystems.

$$\begin{aligned} &\sum_{j=1}^{NUSI_i} hg_{j,t} + \sum_{w=1}^{NTER_i} g_{T_{i,w,t}} + def_{i,t} - \sum_{j=1}^{NSIS} int_{i,j;i\neq j,t} + \sum_{j=1}^{NSIS} int_{j,i;i\neq j,t} \\ &\quad = DEMLIQ_{i,t} \end{aligned} \tag{3}$$

Here, $hg_{j,t}$ is the hydro generation (MWmonth); $int_{j,i;i\neq j,t}$ and $int_{i,j;i\neq j,t}$ is the energy exchange (imported and exported) between subsystems (MWmonth) and $DEMLIQ_{i,t}$ is the net demand of each subsystem (MWmonth), that in this case represents the total demand minus the estimate generation from small hydropower stations that are not centrally dispatched.

The ECFs represent the temporal coupling of the current decisions and their future consequences on the operation costs. Eq. (4) is very important for the problem because it is responsible for coupling the dispatch of the individual power plants with the dispatch based on energy equivalent subsystems. Thus, there is no need to use an iterative process. Each stage has only one solved non-linear programming problem that is dispatched to individual power plants that access an ECF based on energy equivalent subsystems. For each cut of the ECF, a restriction should be included, which is given by Eq. (4). The cumulative producibility used in Eq. (5) is calculated based on the sum of the power plant producibility and all its cascading downstream flows to the ocean.

$$\alpha_{t+1} \geqslant \omega_c + \sum_{i=1}^{NSIS}\pi_{v_{c,i,t+1}} \times EARM_{i,t+1} + \sum_{i=1}^{NSIS}\sum_{p=1}^{NPARp}\pi_{EAF_{p,c,i,t+1}} \times ENA_{i,t-p+1} \tag{4}$$

$$EARM_{i,t} = \sum_{r=1}^{NDAM_i} VA_{r,t} \times \rho_{r,t}^{acum} \tag{5}$$

Here, ω_c is the constant term of c-th Benders' cut (\$), $NPARp$ is the maximum order of the PAR(p) model, $ENA_{i,t-p+1}$ is the previous month natural inflow (MWmonth), $EARM_{i,t+1}$ is the stored Energy (MWmonth), $\pi_{v_{c,i,t+1}}$ is the coefficient of the c-th cut constructed at stage t and associated with the storage of the subsystem or power plant i, $\pi_{EAF_{p,c,i,t+1}}$ is the coefficient of the j-th cut constructed at stage t and associated with the flow of the past p-th stage and to the subsystem or power plant i, $\rho_{r,t}^{acum}$ is the cumulative producibility associated with the power plant r and $NDAM_i$ is the number of power plants with reservoirs.

The constraints shown in Eqs. (6)–(10) represent the operational limits of the generators and the possible limits for exchange between the subsystems.

$$0 \leqslant vt_{j,t} \leqslant \overline{vt_{j,t}} \tag{6}$$

$$\underline{va_{j,t+1}} \leqslant va_{j,t+1} \leqslant \overline{va_{j,t+1}} \tag{7}$$

$$0 \leqslant vv_{j,t} \leqslant \infty \tag{8}$$

$$\underline{g_{T_{i,w,t}}} \leqslant g_{T_{i,w,k,t}} \leqslant \overline{g_{T_{i,w,t}}} \tag{9}$$

$$0 \leqslant int_{i,j,t} \leqslant \overline{int_{i,j,t}} \tag{10}$$

Here, $\overline{vt_{j,t}}$ represents the maximum turbined outflow of the hydropower plants (hm^3), $\underline{va_{j,t+1}}$ and $\overline{va_{j,t+1}}$ represent the minimum and the maximum storage limits of the hydropower plants (hm^3), $\underline{g_{T_{i,w,t}}}$ and $\overline{g_{T_{i,w,t}}}$ represent the minimum and the maximum storage limits of the hydropower plants (MWmonth) and $\overline{int_{i,j,t}}$ is the maximum limit of the energy exchange between the subsystems (MWmonth).