Electric Power Systems Research 141 (2016) 264–271

Contents lists available at ScienceDirect

Electric Power Systems Research

journal homepage: www.elsevier.com/locate/epsr

Maximizing hydro share in peak demand of power systems long-term operation planning

Rafael Bruno S. Brandi [a,b], Tales Pulinho Ramos [a,b], Pedro A.M.-S. David [c], Bruno Henriques Dias [a,*], Ivo Chaves da Silva Junior [a], André Luís Marques Marcato [a]

[a] Department of Electrical Energy, Federal University of Juiz de Fora, Juiz de Fora, Brazil
[b] Education and Technology Department Campus Juiz de Fora, Electricity Group, Federal Institute of Education, Science and Technology of Minas Gerais, Brazil
[c] EPE – Brazilian Energy Research Company, Rio de Janeiro, Brazil

ARTICLE INFO

Article history:
Received 26 November 2015
Received in revised form 29 July 2016
Accepted 30 July 2016

Keywords:
Long-term operation planning
Hydrothermal systems
Peak demand

ABSTRACT

This paper presents an improvement in the long-term hydrothermal system operation planning by including peak generation as a decision variable in the simulations, in order to better operate the hydro plants. Although this has been widely considered in the short-term, the objective is to correctly set the power system operation planning to avoid instantaneous shortages and blackouts. Thus, the instantaneous generation capacity is included in the objective function in order to better consider this variable in long-term operation planning. The results show that it is possible to significantly increase peak power by simply modifying the operation of hydro plants. Moreover, this approach does not present a significant increase in the operation costs.

1. Introduction

The peak power supply was not a concern in power systems with controllable power generation, such as thermal and hydropower with large reservoirs. However, considering environmental constraints [1,2] and/or inappropriate topography to build large reservoirs [3], allow only the building of run-of-the-river hydropower plants, which has a limited power supply capacity in dry seasons.

Also, the huge expansion of wind and solar power plants, which are intermittent, make the peak power supply a point to be regarded carefully, both in long and short run planning as they increase the uncertainties in the system operation. In some systems they do not represent a large share yet. For example, they account for about 2% of total generation in the Brazilian power system in 2015. So, this kind of generation is generally discounted from the demand as a deterministic amount and they are not considered in the optimization process. Even so, some works focus on this problem and model renewable generation uncertainty impact in the operation as seen in [4].

Power systems long term operation planning (LTOP) studies are of significant importance for hydropower systems with large reservoirs, to supply the demand continuously along time [5,6]. Those planning studies may consider a 5-year horizon or longer [7]. In this context, LTOP studies are important to maintaining energy supply security and avoiding load shedding or the reservoirs to reach a very low storage level even at the end of drought periods.

In general, the LTOP studies usually consider the monthly load by its average loads or discretized in a few levels (light/medium/heavy), not considering the instantaneous peak load. The peak load is usually considered in short-run studies but not in long-run studies.

Although, the maximum generation capacity in a given instant depends on the level of the reservoirs. Reservoir levels are basically determined by LTOP models, so the maximum generation that is generally used during peak demands could be included in LTOP models.

It is important to highlight that hydro plants can turbine maximum outflow instantaneously without a significant change in their storage volume. This outflow is limited by the turbine limits without significantly changing their storage volume. Thus, in the context of power planning, it is possible to optimize hydro generation along the time (energy) and instantaneous peak power in the same planning model.

In long-term models, the effect of hourly load variations is represented by different load levels. In Brazil, there are three load levels. The heavy load level represents, on average, the effect of those periods of higher demand by associating a heavier load

* Corresponding author.
E-mail address: bdias@ieee.org (B.H. Dias).

http://dx.doi.org/10.1016/j.epsr.2016.07.027
0378-7796/

with a certain percentage of duration of the whole load (generally about 10%).

Although this heavy load level is still related to a mean monthly generation value during the high demand time of the day, the important aspect of analyzing the impact of the instantaneous balance between supply and demand still remains a long-term assessment. Essentially, the available margin of peak power must be known in order to avoid faults or blackouts, which reinforces the importance of the approach proposed in this paper. As mentioned before, the peak power supply is generally treated in the short-run planning where the horizon is shorter, usually hours [8–11].

This paper presents an improvement in the long-term hydro-thermal system operation planning by including peak hydro generation as a decision variable in the LTOP simulations, in order to better operate the hydro plants. So, the instantaneous generation capacity is included in the objective function in order to better consider this variable in long-term operation planning. The results show that it is possible to significantly increase peak power by simply modifying the operation of hydro plants, thus the increase in the peak generation hydro share represents a reduction in the operation costs due to the reduction of the thermal share.

The paper is outlined as follows. Section 2 presents the nomenclature used in the equations of the paper. Section 3 details the proposed methodology that includes the maximum peak generation variable in the optimal simulation of the LTOP problem. In Section 4, two case studies are presented utilizing data from the Brazilian power system and considering subsystems and individual representations. Finally, conclusions are drawn in Section 5.

2. Nomenclature

For the following definitions, consider s as a given subsystem and t as the stage under analysis. We have the following:

CD_s	marginal deficit cost associated to subsystem s (R$/MWh)
$CT^t_{n,s}$	cost of operation of thermal unit n in subsystem s, stage t (R$/MWh)
D^t_s	demand to be met in subsystem s, stage t (MWmonth)
def^t_s	deficit in subsystem s, stage t (MWmonth)
$EARM^{t+1}_s$	stored energy in subsystem s at beginning of stage $t+1$ (MWmonth)
ENA^{t-p+1}_s	natural inflow to subsystem s related to stage $t+p+1$ (MWmonth)
$ENGOL^t_{i,s}$	maximum turbined outflow of plant i in subsystem s, stage t (m^3/s);
$gt^t_{n,s}$	generation of thermal plant n in subsystem s, stage t (MWmonth)
$GTMAX_{n,s}$	maximum thermal generation of plant n in subsystem s (MWmonth)
$GTMIN_{n,s}$	minimum thermal generation of plant n in subsystem s (MWmonth)
$hefet_{i,s,c}$	net head of turbines, set c of plant i in subsystem s (m)
$HJUS_{i,s}$	tail of plant i in subsystem s (m)
$hl^t_{i,s}$	net head of hydro plant i subsystem s in stage t (m)
$hmon^t_{i,s}$	head of plant i in subsystem s, stage t (m)
$int^t_{ss,s,s\neq ss}$	energy exchange to subsystem s from subsystem ss (MWmonth)
$int^t_{s,ss,s\neq ss}$	energy exchange to subsystem ss from subsystem s (MWmonth)
$INTMAX^t_{s,ss,s\neq ss}$	maximum energy exchange from subsystem s to subsystem ss in stage t (MWmonth)
$IPH_{i,s}$	programmed unavailability index of plant i in subsystem s
$M_{i,s}$	set of hydro plants immediately upstream of plant i in subsystem s
$NCjMaq_{i,s}$	number of generator sets of plant i in subsystem s
$NMaqCj^t_{i,s,c}$	number of generators in the set c of plant i in subsystem s, stage t
$NPARp$	maximum order of inflow time series model PAR(p)
$NSIS$	number of subsystems in the study case
$NTER_s$	number of thermal units of subsystem s
$NUSI_s$	number of hydro plants in subsystem s
$PCV_{i,s,j}$	coefficients j of height-volume polynomial to plant i in subsystem s
$PHIDR_{i,s}$	hydraulic losses of plant i in subsystem s (m)
$Pmax^t_{i,s}$	maximum available power to plant i in subsystem s, stage t (MW)
$Pnom^t_{i,s}$	nominal power of generators of plant i in subsystem s, stage t (MW)
$QI^t_{i,s}$	incremental inflow to hydro plant i in subsystem s, stage t (hm^3/month)
$Qmin_{i,s}$	minimal outflow of plant i in subsystem s (hm^3/month)
$TEIFH_{i,s}$	forced unavailability index of plant i in subsystem s
$va^{t+1}_{i,s}$	stored volume of hydro plant i in subsystem s, stage $t+1$ (hm^3)
$VA^t_{i,s}$	stored volume in the beginning of plant i in subsystem s, stage t (hm^3)
$Vevap^t_{i,s}$	evaporated volume in the reservoir of hydro unit i in subsystem s, stage t (hm^3)
$VMAX_{i,s}$	maximum volume of plant i subsystem s (hm^3)
$VMIN_{i,s}$	minimum volume of plant i subsystem s (hm^3)
$vt^t_{i,s}$	turbined outflow of hydro plant i in subsystem s, stage t (hm^3)
$vv^t_{i,s}$	spillage outflow of plant i in subsystem s, stage t (hm^3)
w_j	jth term of Benders' cut (R$)
z_t	system operation cost at stage t
α_{t+1}	future cost associated to stage t (R$)
$\beta_{i,s}$	constant that depends on the characteristics of the turbine – 1.2 for Kaplan and 1.5 for Francis or Pelton of hydro plant i in subsystem s
$\rho^t_{i,s}$	hydropower production rate of plant i in subsystem s associated to its final storage volume at the end of stage t (MW/hm^3)
μ	benefit value
$\pi^{t+1}_{EAFp_{j,s}}$	coefficient of the jth cut related to stage $t+1$ associated with the inflow of the pth past stage, in subsystem s (R$/MWmonth)
$\pi^{t+1}_{v_{j,s}}$	coefficients of the jth cut constructed in stage $t+1$ associated with water storage in subsystem s (R$/$hm^3$)

3. Methodology

In this paper, the individual hydroelectric power plant model is used to model the power system. A detailed approach to that model in the LTOP problem has already been presented in many references, making use of stochastic dual dynamic programming (SDDP) [12–14]. For a further description of those equations, see [15,16]. The equations of this problem are as follows:

$$\min(z_t) = \sum_{s=1}^{NSIS}\left(\sum_{n=1}^{NTER_s}(CT^t_{n,s}\times gt^t_{n,s}) + CD_s\times def^t_s - \mu\sum_{i=1}^{NUSI_s}\mathrm{Pmax}^t_{i,s}\right) + \alpha_{t+1} \quad (1)$$

$$va^{t+1}_{i,s} + vt^t_{i,s} + vv^t_{i,s} - \sum_{j\in M_{i,s}}^{NUSI_s}(vt^t_{j,s} + vv^t_{j,s}) = VA^t_{i,s} + QI^t_{i,s} - Vevap^t_{i,s} \quad (2)$$

$$\sum_{n=1}^{NTER_s} gt^t_{n,s} + \sum_{i=1}^{NUSI_s}\rho^t_{i,s}\times vt^t_{i,s} + \sum_{ss=1}^{NSIS} int^t_{ss,s,s\neq ss} - \sum_{ss=1}^{NSIS} int^t_{s,ss,s\neq ss} + def^t_s = D^t_s \quad (3)$$

$$vt^t_{i,s} + vv^t_{i,s} \geq Qmin_{i,s} \quad (4)$$

$$\sum_{ss=1}^{NSIS} int^t_{ss,s,s\neq ss} - \sum_{ss=1}^{NSIS} int^t_{s,ss,s\neq ss} = 0 \quad (5)$$

$$Pmax^t_{i,s} = (1 - TEIFH_{i,s})(1 - IPH_{i,s}) \times \sum_{c=1}^{NCjMaq_{i,s}}\left[NMaqCj^t_{i,s,c}\times Pnom_{i,s,c} \times \min\left(\left(\frac{hl^t_{i,s}}{hefet_{i,s,c}}\right)^{\beta_{i,s}}, 1.0\right)\right] \quad (6)$$