Operational hydropower scheduling with post-spot distribution of reserve obligations

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***Abstract*—As a reliable and flexible electric power source, hydropower can quickly adjust its generation level and provide reserve power to balance the power fluctuations in the system. In this paper, we assume that the day-ahead spot market is cleared and the obligation for each reserve type is already contracted in a preceding market. Then the question is how to make the optimal decision to determine, for each unit and for each time step, the dispatched volume for the day-ahead market and the reserved capacity for various types of reserve. We formulate the constraints added to the optimization problem for distributing reserve obligations. The proposed mathematical formulation is based on an operational hydropower scheduling model used by most large hydropower producers in Scandinavia.**

***Index Terms*—Hydroelectric power generation, mathematical programming, optimal scheduling.**

I. INTRODUCTION

In any electric system, power generated must be maintained in constant equilibrium with power consumed. Otherwise, imbalance between generation and consumption leads to a deviation of the system frequency from its set-point values. Recent years have witnessed increasing penetration of wind and solar power in the power market. The large amount of production that varies within short period increases the need for ancillary services to secure the supply of electricity. As a reliable and flexible electric power source, hydropower can quickly adjust its generation level and provide reserve power to balance the power fluctuations in the system. Therefore, more and more hydropower producers choose to participate in both energy and ancillary services markets.

This practice brings about the new operational challenges for the hydropower producers. Two of the widely discussed challenges are: (1) how to develop bidding strategies in one market while considering the possibility to trade on other markets [1], and (2) how to find the feasible production plans with capacity allocated in multiple markets [2]. This paper focuses on the second challenge. That is, given the cascaded watercourses that consist of a large number of reservoirs, plants and turbines, the producer has to make the optimal decision to determine, for each unit and for each time step, the dispatched volume for the day-ahead market and the reserved capacity for various types of reserve. We formulate the constraints added to the optimization problem for distributing reserve obligations. The proposed mathematical formulation is based on an operational hydropower scheduling model, Short-term Hydro Optimization Program (SHOP), used by most large hydropower producers in Scandinavia [3].

In the literature, optimization models from the perspective of a hydropower producer to maximize the expected profit by participating in both the energy and the ancillary service markets have been extensively discussed. In [4] and [5], deterministic models are presented, both on the plant level. [6] introduces uncertainties about market participation and price, but simplifies the problem by limiting the modeling to non-hydraulically coupled hydroelectric plants. [7] proposes an explicit representation of a multi-reservoir system and focuses on the secondary regulation reserve market of the Spanish power system. [8] develops a method suitable for solving the medium-term hydropower scheduling problem. In this paper, we extend the work of [2] on the allocation of primary reserves to cover all the reserves. To the best of our knowledge, this is the first time that reserve constraints are formulated on such a detailed level for an operational scheduling model used in the real world.

Considerable differences exist between the reserve types defined in various countries or regions. These differences often lead to confusion because they extend not only to the technical specification of the reserve services but also to the terms used to describe them. To reduce this confusion, in this paper we use ENTSO-E terminology [9]. However, it is worth mentioning, that although we mainly discuss the operation in Northern Europe Synchronous Area (comprises Finland, Sweden, Norway and Eastern Denmark), the proposed method can be easily adapted to achieve the specific requirements of other markets.

The framework of the load-frequency control (LFC) processes consists of Frequency Containment Reserves (FCR), Frequency Restoration Reserves (FRR) and Replacement Reserves (RR). They usually can be mapped to three levels of controls, i.e. Primary, Secondary and Tertiary [10]. The frequency quality is maintained by keeping the system frequency as close as possible to Nominal Frequency (50 Hz). In Northern Europe, FCR is defined as two response rates, one for the normal operating range (FCR_N) and one for disturbance (FCR_D). FCR_N will be activated automatically in both directions when the frequency is between 50.1 Hz and 49.9 Hz. FCR_D is automatically activated if the frequency falls to the interval of 49.9 Hz to 49.5 Hz. If the imbalance continues for several minutes, FRR will take over to restore the frequency back to 50 Hz. If further regulation is necessary, RR will be activated manually by the transmission system operators (TSOs).

Control reserves can be provided both upwards (to increase the active power production in case of a low frequency) and downwards (to reduce the active power production in case of a high frequency), but not necessarily reacts symmetrically in both directions. We therefore give a separate definition of up- and down-regulation bands for each level of frequency control. Note that since FCR_D is activated only when the frequency falls, we assume this type of reserve is limited to up-regulation. TABLE I lists all the reserve types used in this paper.

TABLE I ABBREVIATION AND EXPLANATION OF THE RESERVE TYPES

Abbreviation	Explanation
FCR_N_UP	Frequency Containment Reserve for the Normal operating range for Up-regulation
FCR_N_DOWN	Frequency Containment Reserve for the Normal operating range for Down-regulation
FCR_D_UP	Frequency Containment Reserve for the Disturbance for Up-regulation
FRR_UP	Frequency Restoration Reserve for Up-regulation
FRR_DOWN	Frequency Restoration Reserve for Down-regulation
RR_UP	Replacement Reserve for Up-regulation
RR_DOWN	Replacement Reserve for Down-regulation

When the day-ahead spot market is cleared and a bid is accepted, the load obligation committed in the bid must be provided. In this paper, we assume that the obligation for each reserve type is already contracted in a preceding market. Then the question is how to integrate the commitments of generating units that participate in the LFC processes as a part of the optimal production scheduling after spot clearing.

In theory, a generating unit could be simultaneously present in all types of reserve services. If there is a need for up-regulation, the unit can increase its power generation from the current working point to the full capacity. Similarly, the unit can reduce the output to meet the reserve requirements for down-regulation. When providing FCR and FRR, the unit must be producing electricity (using a fraction of its capacity) in order to spin at the right speed to synchronize itself with the electrical grid. By contrast, delivery of RR_UP does not have the same requirements.

To cover all the possible combinations of available units to deliver reserves, and to represent the fact that capacity of a unit assigned for different reserves can change from time to time, we introduce a time dependent reserve pool, i.e. Reserve Group, to connect the units that can contribute to the reserves with the obligation for those reserves. For example (Fig. 1), all the units in both Plant A and Plant B can deliver FCR_N_UP (Reserve Group 1). Only one unit is dedicated to cover RR_UP (Reserve Group 2). In Reserve Group 3, there are obligations to FRR_UP and FRR_DOWN. Unit G1 in Plant B can contribute to both of the reserves but Unit G2 only contributes to FRR_UP. Once the assignment of Reserve Group is given, the optimization problem becomes how to distribute the reserve obligations among the chosen units, and meanwhile, to determine the optimal production level for all the units during the planning horizon.

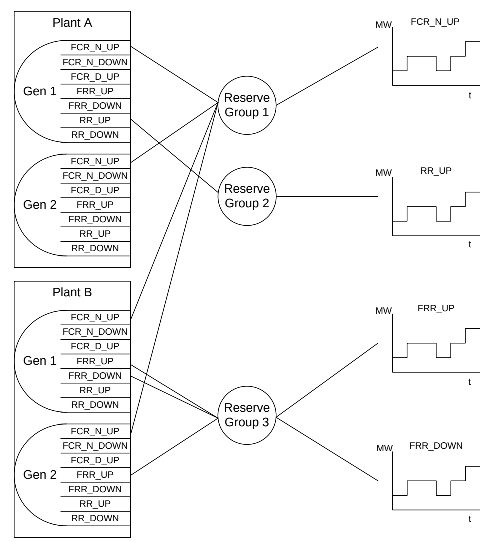

Figure 1. Example of reserve groups in SHOP

II. MATHEMATICAL FORMULATION

In this section, we mainly explain how the reserve constraints are formulated in SHOP. Because of the page limitation, we only present the basic constraints concerning hydrological balance in the reservoirs and power generation in the plants. The non-linear plant head optimization, start and stop cost of units, power loss in the tunnels are not included. The reserve functionality has also been implemented for Pelton turbines and variable speed pumps, but in this paper we only focus on Francis turbines.

In this paper we use hourly time resolution and the planning horizon is one week. In the first 24 hours, the load obligation from the day-ahead spot market is given. In the remaining hours, the power generation is optimized against the forecasted price in the energy market. Reserve obligations are assumed known for the whole planning period. The hydrological constraints do not take water usage related to activation of reserves into account.

A. Sets and Indices

T Set of time periods (hourly resolution), index $t \in T$.

R Set of all the reserve types (TABLE I), index $r \in R$.

R^{UP} Set of reserve types for up-regulation except for RR_UP, i.e. FCR_N_UP, FCR_D_UP and FRR_UP.

R^{DOWN} Set of reserve types for down-regulation, i.e. FCR_N_DOWN, FRR_DOWN and RR_DOWN.

R^{FCR} Set of reserve types related to FCR, i.e. FCR_N_UP, FCR_N_DOWN and FCR_D_UP.

G Set of reserve groups, index $g \in G$.

S Set of plants, index $s \in S$.

I_s Set of units in plant s, index $i \in I_s$.

I_{gt}^r Set of units in reserve group g of reserve type r in period t.

K_s Set of direct upper reservoirs of plant s, index $k \in K_s$.

B. Paramters

P_t^{SPOT} Forecasted price in the spot market in period t, $t = 25, \dots, T$, (€/MWh).

$P_{k,T}^{END}$ Water value at the end of planning horizon T of the reservoir k (€/MWh).

$V_{k,0}^{INIT}$ Initial volume of reservoir k (Mm^3).

NI_{kt} Natural inflow forecast at reservoir k in period t (m^3/s).

E_s Energy conversion factor for plant s (MWh/Mm^3).

$MW_{ist}^{MAX\_PROD}$ Maximum production of unit i in plant s in period t (MW).

$MW_{ist}^{MIN\_PROD}$ Minimum production of unit i in plant s in period t (MW).

$MW_{is}^{NOM\_PROD}$ Nominal production of unit i in plant s (MW).

MW_t^{PROD} Load obligation in period t, $t = 1, \dots, 24$, (MW).

D_{ist}^{MAX} Maximum unit droop of unit i in plant s in period t.

D_{ist}^{MIN} Minimum unit droop of unit i in plant s in period t.

D_{ist}^{FIX} Given unit droop of unit i in plant s in period t.

W Minimum unused fraction of maximum capacity for a unit delivering FCR (%).

B^r Bandwidth of the regulation limit on reserve type r, $r \in R^{FCR}$.

MW_{gt}^r Obligation to reserve type r in reserve group g in period t (MW).

PC_t^{PROD} Cost for not fulfilling the load obligation in period t, $t = 1, \dots, 24$, (€/MW).

SC_t^{PROD} Cost for exceeding the load obligation in period t, $t = 1, \dots, 24$, (€/MW).

PC_{gt}^r Cost for not fulfilling the obligation to reserve type r in reserve group g in period t (€/MW).

SC_{gt}^r Cost for exceeding the obligation to reserve type r in reserve group g in period t (€/MW).

DC_{ist}^{DROOP} Unit droop cost of unit i in plant s in period t (€).

X A large number used to ensure that a constraint is not binding. In SHOP, $X = 2 \cdot MW_{ist}^{MAX\_PROD}$.

C. Variables

There are two types of variables, binary variables and non-negative continuous variables.

$\omega_{ist} \in \{0, 1\}$ 1 if unit i in plant s is running in period t, 0 otherwise.

$\varphi_{ist}^{FCR} \in \{0,1\}$ 1 if unit i in plant s contributes to reserve types related to FCR in period t, 0 otherwise.

$\gamma_{ist}^{RR\_UP} \in \{0,1\}$ 1 if unit i in plant s contributes to RR_UP in period t, 0 otherwise.

v_{kt} Water volume of reservoir k at the end of period t (Mm^3).

mw_{ist}^{PROD} Power produced by unit i in plant s in period t (MW).

pmw_t^{PROD} Amount of load obligation not fulfilled in period t, $t = 1, \dots, 24$, (MW).

smw_t^{PROD} Volume exceeding the load obligation in period t, $t = 1, \dots, 24$, (MW).

q_{ist} Flow going through unit i in plant s in period t (m^3/s).

d_{ist} Unit droop of unit i in plant s in period t.

l_{ist}^r Delivery limit on reserve type r of unit i in plant s in period t (MW).

mw_{ist}^r Power reserved for reserve type r of unit i in plant s in period t (MW).

pmw_{gt}^r Amount of reserve obligation not fulfilled for reserve type r in reserve group g in period t (MW).

smw_{gt}^r Volume exceeding the obligation to reserve type r in reserve group g in period t (MW).

D. Constraints

1) Basic constraints

In (1) and (2), we model the hydrological balance of reservoir k that is directly connected to downstream plant s: the end water volume of reservoir k in period t is the end volume in period $t-1$ plus the natural inflow minus the sum of outflow going through each unit. Flow due to spillage and time delay, and discharge from upper objects are not presented here. Hydrological laws for reservoirs with pressurized connections between each other are irrelevant to this paper and hence omitted.

$$v_{k,0} = V_{k,0}^{INIT}, \forall k \in K_s, s \in S. \tag{1}$$

$$v_{kt} = v_{k,t-1} + 0.0036 \cdot \left(NI_{kt} - \sum_{i \in I_s} q_{ist} \right) \quad k \in K_s, s \in S, t \in T. \tag{2}$$

For a specific unit, the power generation depends on the net plant head and the flow going through that unit. It also relies on the generator efficiency and head-dependent turbine efficiency. Based on the volume of upstream reservoir $v_{k,t-1}$ and the volume of downstream reservoir $v_{k+1,t-1}$ (if water level of downstream reservoir is higher than the outlet line of the plant), the gross plant head can be calculated in a straightforward way. However, the net plant head is influenced by the loss in the main tunnel and the penstocks, which is a quadratic equation of the total flow going through the tunnels. The detailed calculation is beyond the scope of this paper (Interested readers can refer to [11]), and therefore, we use the function $f(q_{ist}, v_{k,t-1}, v_{k+1,t-1})$ in (3) to represent the transformation from the discharge q_{ist} to the production mw_{ist}^{PROD}.

$$mw_{ist}^{PROD} = f(q_{ist}, v_{k,t-1}, v_{k+1,t-1}) \quad i \in I_s, s \in S, t \in T. \tag{3}$$

In the first 24 hours of the planning horizon, the load obligation comes from the cleared day-ahead spot market. Constraint (4) ensures it will be fulfilled.

$$\sum_{\substack{i\in I_s\\ s\in S}} mw_{ist}^{PROD} + pmw_t^{PROD} - smw_t^{PROD} = MW_t^{PROD} \quad t = 1,\ldots,24. \tag{4}$$

2) Constraints on regulation limits of FCR

In Norway, a unit can contribute to reserve types concerning FCR (i.e. FCR_N_UP, FCR_N_DOWN and FCR_D_UP) only if the unused capacity is no less than 2% (W%) of the maximum capacity [12]. In other countries, the value of W can vary, or even no such capacity rule exists. To make it universally applicable, we utilize binary variable φ_{ist}^{FCR} in (5) to model the capacity regulation. If the unused capacity of unit i is less than W% of the maximum production, φ_{ist}^{FCR} will be forced to be 0, which is expressed as

$$mw_{ist}^{PROD} \le MW_{ist}^{MAX\_PROD} - W \cdot MW_{ist}^{MAX\_PROD} \cdot \varphi_{ist}^{FCR} \quad i \in I_s, s \in S, t \in T. \tag{5}$$

In addition, only running units can contribute to the commitment of FCR. This requirement can be modelled as

$$\varphi_{ist}^{FCR} \le \omega_{ist}, \; i \in I_s, s \in S, t \in T. \tag{6}$$

The unit droop (d_{ist}) usually varies from 1 to 12. It can either be given as input data (parameter) or defined as a decision variable. In order to avoid non-linearity, in SHOP, it is expressed as reciprocal d_{ist}^{-1} and always treated as a variable. Therefore, if d_{ist} is given as a parameter, we fix d_{ist}^{-1} to the given value, as in

$$d_{ist}^{-1} = (D_{ist}^{FIX})^{-1}, \; i \in I_s, s \in S, t \in T. \tag{7}$$

If d_{ist} is a decision variable, it should be between a minimum and a maximum value, as shown in (8).

$$(D_{ist}^{MAX})^{-1} \le d_{ist}^{-1} \le (D_{ist}^{MIN})^{-1}, \; i \in I_s, s \in S, t \in T. \tag{8}$$

The theoretical values for regulation limits on FCR are calculated on the basis of d_{ist}^{-1}. They are modelled in (9). B^r is the bandwidth of the regulation limit. For instance, in Norway, both $B^{FCR\_N\_UP}$ and $B^{FCR\_N\_DOWN}$ are 0.1 and $B^{FCR\_D\_UP}$ is 0.4.

$$l_{ist}^r = 2 \cdot B^r \cdot MW_{is}^{NOM\_PROD} \cdot d_{ist}^{-1} \cdot \varphi_{ist}^{FCR}, \quad r \in R^{FCR}, i \in I_s, s \in S, t \in T. \tag{9}$$

To keep the constraint tractable as a standard mixed integer programming (MIP) formulation, we split (9) into two constraints presented below:

$$l_{ist}^r \le 2 \cdot B^r \cdot MW_{is}^{NOM\_PROD} \cdot d_{ist}^{-1}, \quad r \in R^{FCR}, i \in I_s, s \in S, t \in T. \tag{10}$$

$$l_{ist}^r \le X \cdot \varphi_{ist}^{FCR}, \; r \in R^{FCR}, i \in I_s, s \in S, t \in T. \tag{11}$$

Equation (11) secure that the regulation limits l_{ist}^r will be 0 if φ_{ist}^{FCR} is 0 (e.g., the capacity regulation is activated and the production is above W% of the maximum limit). Otherwise, l_{ist}^r is restricted by the theoretical value in (10).

The actual delivery of FCR should be no more than its regulation limit. This is expressed as

$$mw_{ist}^r \le l_{ist}^r, \; r \in R^{FCR}, i \in I_s, s \in S, t \in T. \tag{12}$$

3) Constraints on delivery of reserve obligations except for RR_UP

If a unit is running, the unused capacity can contribute to the obligations of FCR and FRR for up-regulation. That is, it may produce more power in the electric system if needed. If the unit is standing still, there is no production or reserve delivery. This is represented as

$$mw_{ist}^{PROD} + \sum_{r\in R^{UP}} mw_{ist}^r \le MW_{ist}^{MAX\_PROD} \cdot \omega_{ist} \quad i \in I_s, s \in S, t \in T. \tag{13}$$

As to the reserve obligations for down-regulation, the sum of allocated capacities for each reserve type should be within the minimum production limit. The following constraint is introduced to achieve this purpose.

$$MW_{ist}^{MIN\_PROD} \cdot \omega_{ist} \le mw_{ist}^{PROD} - \sum_{r\in R^{DOWN}} mw_{ist}^r \quad i \in I_s, s \in S, t \in T. \tag{14}$$

4) Constraints on delivery of reserve obligation to RR_UP

Despite the similarity from control point of view, manual FRR activation and RR activation lead to different control performances due to different activation time frames. RR includes operating reserves with activation time from 15 minutes up to hours [10]. Therefore, the units assigned to deliver RR_UP are not necessarily running. Instead, they can stand still but be started if required. Then we have to take two situations into account:

- When a unit is standing still, if it is required to deliver RR_UP, the minimum volume should be no less than its minimum production and the maximum volume should be no greater than its maximum production;
- When a unit is running, the capacity of providing RR_UP must be between 0 and the maximum limit.

To adequately model these two situations, we introduce following constraints:

$$MW_{ist}^{MIN\_PROD} \cdot \left(\gamma_{ist}^{RR\_UP} - \omega_{ist}\right) \le mw_{ist}^{RR\_UP}, \quad i \in I_s, s \in S, t \in T. \tag{15}$$

$$mw_{ist}^{PROD} + \sum_{r\in R^{UP}} mw_{ist}^r + mw_{ist}^{RR\_UP} \le MW_{ist}^{MAX\_PROD}, \; i \in I_s, s \in S, t \in T. \tag{16}$$

$$mw_{ist}^{RR\_UP} \le X \cdot \gamma_{ist}^{RR\_UP}, \; i \in I_s, s \in S, t \in T. \tag{17}$$

If the unit is standing still ($\omega_{ist} = 0$), it still can be committed to provide RR_UP ($\gamma_{ist}^{RR\_UP} = 1$). In this case, equation (15) indicates the delivery of RR_UP must be above the minimum production. Equation (16) ensures that the delivered amount will be no more than maximum production, since mw_{ist}^{PROD} and $\sum_{r\in R^{UP}} mw_{ist}^r$ are both 0 (restricted by (13)).

If the unit is running ($\omega_{ist} = 1$) and contributes to RR_UP ($\gamma_{ist}^{RR\_UP} = 1$), equations (15) and (16) then imply that the minimum delivery of RR_UP can be 0 but the sum of the capacity assigned to each reserve type cannot exceed the maximum production.

Constraint (17) is introduced to make sure $mw_{ist}^{RR\_UP}$ will be 0 if $\gamma_{ist}^{RR\_UP} = 0$.

5) Constraints on reserve groups

For a reserve group g of reserve type r, several units will be assigned to it for the contribution in the specific reserve market. We summarize the actual reserve delivery of these units. The penalty and slack variables are used to avoid infeasibilities, and expressed in (18):

$$\sum_{i,s \in I_{gt}^{r}} mw_{ist}^{r} + pmw_{gt}^{r} - smw_{gt}^{r} = MW_{gt}^{r} \qquad r \in R, g \in G, t \in T. \tag{18}$$

6) Objective function

The goal of the model is to maximize the profit during the planning horizon for a hydroelectricity producer. The profit is the production revenues (first term in (19)) plus the water value at the end of planning horizon (second term) and minus the violation cost for load and reserve obligations (third to sixth terms) and minus the droop cost (last term). Note that the droop cost usually decreases with the increase of the unit droop.

The future marginal water value in a reservoir is assumed to be a fixed value. However, in practice, this value can be expressed as a concave piecewise linear function of the water volume. It is provided by a mid-term scheduling model that would integrate the stochastic nature of inflows and spot prices [13].

$$\begin{aligned} Max \; & \sum_{\substack{i \in I_s \\ s \in S \\ t=25,\dots,T}} P_t^{SPOT} \cdot mw_{ist}^{PROD} + \sum_{\substack{k \in K_s \\ s \in S}} P_{k,T}^{END} \cdot E_s \cdot v_{k,T} \\ & - \sum_{t=1,\dots,24} PC_t^{PROD} \cdot pmw_t^{PROD} - \sum_{t=1,\dots,24} SC_t^{PROD} \cdot smw_t^{PROD} \\ & - \sum_{\substack{r \in R \\ g \in G \\ t \in T}} PC_{gt}^{r} \cdot pmw_{gt}^{r} - \sum_{\substack{r \in R \\ g \in G \\ t \in T}} SC_{gt}^{r} \cdot smw_{gt}^{r} \\ & - \sum_{\substack{i \in I_s \\ s \in S \\ t \in T}} DC_{ist}^{DROOP} \cdot d_{ist}^{-1} \end{aligned} \tag{19}$$

III. NUMERICAL RESULTS

The proposed constraints are implemented in the SHOP model and the resulting optimization problems are solved by CPLEX. SHOP involves two modelling modes: Unit commitment (UC) mode and Close-in mode. In the first mode, a commitment plan concerning which units are committed to run is established by using MIP. After 2 or 3 iterations using successive linear programming method, the result has normally converged. Then a dispatch plan regarding exact generation level is obtained in the Close-in mode [3].

The test case comprises two reservoirs. Each reservoir has one power plant with two identical generating units. The production intervals for the units in PLANT 1 are [80 MW, 310 MW] and nominal production is 310 MW. For the units in PLANT 2, production spans from 50 MW to 250 MW and nominal production is 250 MW. We assume that all the units in both plants are assigned to one reserve group and can provide all the reserve types. The reserve obligations are constant, i.e. FCR_N_UP=40 MW, FCR_N_DOWN=40 MW, FCR_D_UP =50 MW, FRR_UP=60 MW, FRR_DOWN=30 MW, RR_UP =80, and RR_DOWN=40 MW. The costs for not fulfilling or exceeding the load or reserve obligation are 5000 €/MW and the unit droop costs are 100 €/MW.

The test cases are aimed at (A) to examine the result of integration of reserve obligations into optimal production scheduling; (B) to compare the difference in the delivery of FRR_UP and RR_UP; (C) to study the impact of the regulation limits on the distribution of reserve obligations.

A. Integration of Reserve Obligations into Optimal Production Scheduling

We first run the model without reserve obligations and then add the reserve commitments into the optimization model. Fig. 2 contrastingly shows the two production plans. In the first 24 hours, because a load obligation is given and must be followed in both situations, the production plans are the same. However, in the remaining hours, though the quantity of electricity offered still follows the trend of the forecasted electricity price, there is obvious difference after integrating reserve obligations into the scheduling. When the price is low, the units have to keep running to deliver reserves for down-regulation. On the other hand, when the price is high, the units cannot run at the maximum capacity in order to be able to provide reserves for up-regulation.

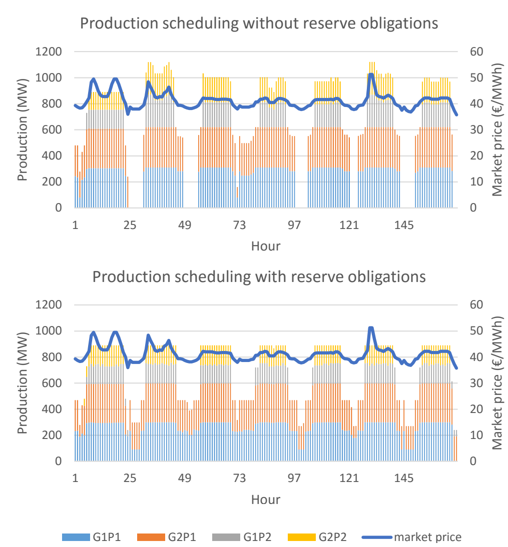

Figure 2. Production scheduling without and with reserve obligations

B. Difference in the Delivery of FRR_UP and RR_UP

Fig. 3 presents the distribution of obligations to FRR_UP and RR_UP among the units in the first 24 hours. As mentioned above, when providing FCR and FRR, a unit must be in operation. Therefore, the obligation to FRR_UP is allocated to those running units for each hour. In contrast to FRR_UP, RR_UP can be delivered by units that stand still. In the first 5 hours, although Unit G1 in Plant 2 (G1P2) is not running, it is assigned to deliver RR_UP. Note that since the minimum production of G1P2 is 50 MW, the minimum volume that can be reserved for RR_UP when it stands still should be no less than 50 MW, as shown in Hour 3 and 5. When it is running, there is no longer such limit, e.g. Hour 9, 12, and 17.

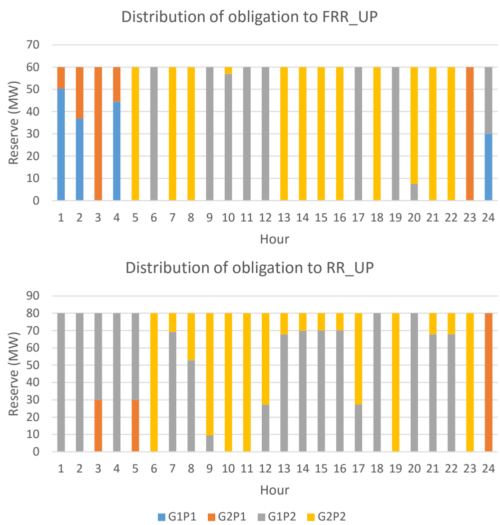

Figure 3. Distirbution of obligations to FRR_UP and RR_UP

C. Impact of the Regulation limits

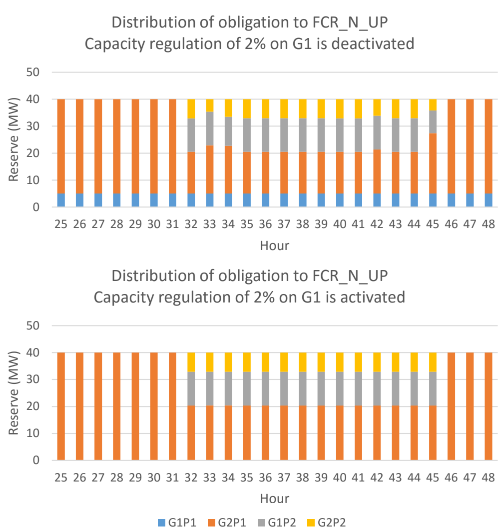

Figure 4. Distribution of obligation to FCR_N_UP without and with the activation of the capacity regulation

The maximum production of Unit G1 in Plant 1 (G1P1) is 310 MW. We now assume that G1P1 has a production schedule of 305 MW, which means the unused capacity of G1P1 is less than 2%. We first run the model by deactivating the capacity regulation ($W = 0$) and then run it again by restoring the regulation and setting $W = 2\%$. Fig. 4 displays the resulting distribution of FCR_N_UP delivery without and with the activation of the capacity regulation in the second day. When the regulation is not activated, the unused capacity of G1P1 (5 MW) can still be reserved to deliver FCR_N_UP. However, when the regulation is activated, G1P1 is not allowed to contribute to any reserves related to FCR.

IV. Conclusion

This paper integrates the distribution of reserve obligations into optimal hydropower scheduling. Detailed mathematical formulation of the related constraints is presented. These constraints are included in an operational scheduling model that is used in the real world. Future developments will focus on integrating the prices for reserves and trading in multiple markets under uncertainty. How to ensure there is enough water in the reservoirs when the committed up-regulations reserves are delivered will be another upcoming subject.

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