CHAIRE EUROPEAN ELECTRICITY MARKETS
Fondation Paris-Dauphine

Working Paper #30

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Sébastien MATHIEU, Marie PETITET, Marie PERROT,
Damien ERNST and Yannick PHULPIN

10.10.2017

DAUPHINE UNIVERSITÉ PARIS

Chaire de recherche soutenue par

RTE EDF EPEXSPOT CELEST

SiSTEM, A MODEL FOR THE SIMULATION OF SHORT-TERM ELECTRICITY MARKETS

Sébastien Mathieu[1], Marie Petitet[2,3,*], Marie Perrot[2], Damien Ernst[1], Yannick Phulpin[2]

[1]University of Liège, Belgium
[2]EDF R&D, France
[3]Chaire European Electricity Markets, Paris-Dauphine University, France

October 10, 2017

Abstract
The aim of this document is to present SiSTEM, a multi-level simulation model of European short-term electricity markets, covering day-ahead and intraday exchanges to balancing activations in real-time, and imbalance settlement. In this model, power companies interact by making offers, notifying their positions to the system operator and impacting the balance of the electric system. The system operator activates balancing energy to restore the balance of the system, using all balancing activation offers, including from balancing reserves. Imbalance settlement implies bidirectional transactions between the system operator and power companies depending on the direction of their imbalance. A simulation of the model is performed by sequentially considering each time step and simulating actors' decisions.

The objective of this model is to understand the problems behind decisions of the actors within the short-term electrical system operation, to provide insights on how these problems can be solved through market design and to see how the decisions are linked together to shape a coherent system. This paper presents different simulation cases of an illustrative system in order to portray main features of the model in a practical and effective manner. In particular, the results show the importance of considering steady-state constraints and notice delays of generation units when looking at short-term issues. Future works could use this model to provide quantitative assessments of short-term market designs.

Key words: Electricity markets, balancing markets, simulation model, multi-level optimization, explicit offers building, steady-state constraints.

Acknowledgment: This work has been funded by EDF. It has also benefited from the support of the Chaire European Electricity Markets (CEEM) of the Université Paris-Dauphine under the aegis of the Foundation Paris-Dauphine, supported by RTE, EDF, EPEX Spot and CELEST.

* Corresponding author: marie.petitet@edf.fr

1. INTRODUCTION

The European Union recently approved the Network Code on Electricity Balancing, which aims at developing cross-border balancing markets [7] this enhancing competition and reducing costs. Further reforms of the European internal electricity market is subject to actual debate following on from legislative proposals from the European commission [21]. Assessing the impact of these regulatory changes is essential and motivates the development of an adequate model. This paper presents the multi-level simulation model SiSTEM aiming to model the short-term electrical system and allowing such analyses.

The introduction starts with a description of the context in Section 1.1, follows with the structure of the model and its objectives in Section 1.2 and ends with a review of the relevant literature in Section 1.3. The rest of the paper is organized as follows. The description of SiSTEM is divided in three parts: the energy market models, the power companies model and the system operator model. These models are the object of Sections 2, 3 and 4, respectively with more detailed information on the models of the production assets in Section 7. To portray main features of the model, results for an illustrative system are given in Section 5. Finally, Section 6 concludes and provides future perspectives for the model.

1.1. Context

Electricity is one of the most complex commodities to exchange due to the physical constraints underlying its production, consumption and transport. Electricity flows quasi-instantaneously through the network. Maintaining electrical system stability requires maintaining the balance between production and consumption at every instant. Unlike other goods, electricity cannot be efficiently stored in large volumes. Hydro-electric storage is limited by its low energy density and conversion efficiency from electrical to mechanical to gravitational energy, and the other way around. Battery capacities are small and costly with respect to the needs for electrical energy. Alternatives exist but still fail to provide an ideal lossless and costless storage solution for electricity.

To maintain the balance between production and consumption, electricity is traded before its actual delivery so that actors within the electrical system know in advance how much they are expected to produce or consume. This expectation only partially delivers in reality since production and consumption are uncertain. Electricity retailers who buy electricity on the wholesale market and sell it to end-user consumers cannot perfectly predict the power consumption of their clients'. Consumers do not inform their retailer that they intend to iron or watch the television in a few hours. Predictions of electrical production from the wind or the sun are as accurate as weather . Production and transmission assets are subject to outages. Given these uncertainties, actors could be tempted to exchange electricity as late as possible to get the best outcome. However, the most flexible production assets are also usually the most expensive ones. Therefore, relying solely on last-minute exchanges would be economically inefficient.

Achieving economic efficiency of electrical production at a large scale is the purpose of electricity markets. A power company willing to satisfy the demands of its consumers may either use its own production assets or buy energy on the electricity markets if it is expected to be cheaper. Exchanges may occur from the long-term, i.e. a few years ahead, to the short-term. This document focuses on European short-term electricity markets, in particular the day-ahead, the intraday and the balancing ones. In Europe at 12:00, the day-ahead market clears offers to buy or sell electrical energy for the next day. This market gives prices for each hour of the next day, which are often taken as reference for other financial transactions of electrical energy. Exchanges occurring after the gate closure of the day-ahead market are carried out in the intraday market. Usually, these exchanges are triggered by changes in forecasts or outages of production units, and give opportunities to power companies to balance their portfolio. The intraday market is different from one European country to another. The number of market periods, i.e. minimum spanning period of a market offer, also depends on the type of product and country e.g. one hour, half an hour, or a quarter of an hour. For instance, the French intraday market allows continuous trading of 30-minute products up to 30 minutes ahead of real-time [18]. Germany opens an hourly intraday market at 15:00 for the next day. At 16:00, the continuous market opens and allows trading 15-minute products up to 30 minutes before delivery begins [14]. In Switzerland, energy on 15 minutes is traded continuously up to one hour ahead [15]. The intraday market of Spain clears hourly products in six sessions occurring at 17:00 and 21:00 in the day-ahead and at 1:00, 4:00, 8:00 and 12:00 in intraday [32]. Since there is no unique clearing, there is no unique price settled in intraday for the same product, i.e., electricity delivered for a given time unit.

While energy markets aim at improving the economic efficiency of its production, the system operator ensures the security of its electrical system. One of its most important tasks is to ensure the equality between production and consumption in real-time. To separate natural monopolies from deregulated activities, the European Commission has, through Article 9 of the Directive 2009/72/EC, prevented the system operator from directly or indirectly performing any of the functions of generation or supply except in emergency situations [20]. The system operator must therefore resort to other methods than taking over production units to ensure the security of its system and have enough time to take actions.

The neutralization delay defines the minimum time needed by the system operator to analyze the impact of a change in the production plan. The term schedule in this document refers to the last schedule defined at the neutralization delay. Each producer must declare to the system operator its injections and off-takes from all its production assets connected to the transmission network. Throughout the day, a producer may define various schedules for its assets. Any change of schedule notified past this delay is rejected. The neutralized schedule can only be modified by the system operator to activate balancing offers or in case of outages. This delay indirectly limits intraday market exchanges since the production schedule cannot be changed.

Differences between production and consumption may still occur due to outages and forecast errors. These differences are balanced by the system operator using the balancing mechanism [10]. Imbalances are solved by three types of balancing capacities: frequency containment reserve, frequency restoration reserve and reserve replacement. The organization of these steps throughout time and space is represented in Figure 1. The frequency containment reserve provides a fast and automatic response proportional to the variation of frequency. This control is distributed among the different countries of a synchronized area and assets of the electrical system. The frequency restoration reserve provides the missing energy in order to release assets participating in the frequency containment process such that they are available for future imbalances. Balancing levers of frequency restoration are usually split into the manual and the automatic part, leading to different activation delays and processes. The reserve replacement occurs after the frequency restoration to either relieve the frequency restoration process, to restore market efficiency, or to improve the security of the system. This model focuses on the balancing energy offered in the frequency restoration and reserve replacement.

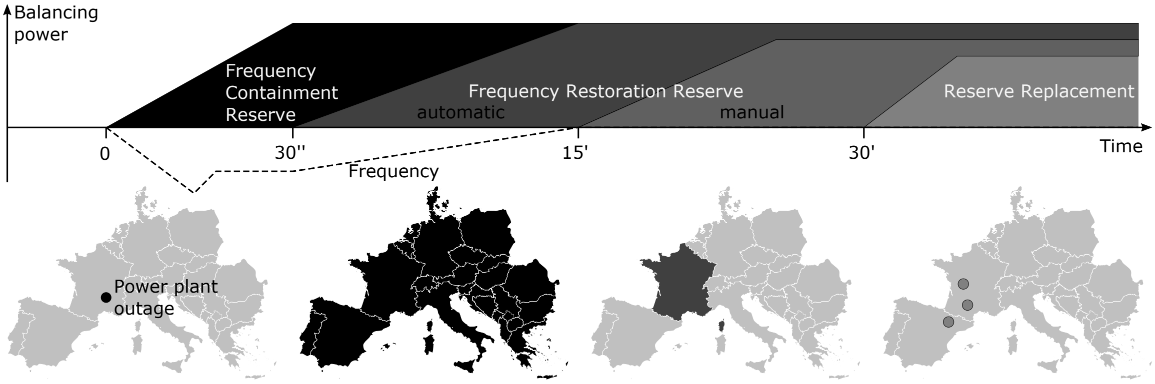


Figure 1: Balancing mechanism hierarchy throughout time and space. Inspired from [8, 11].

Actors with flexible assets, traditionally producers, communicate their flexibility and their activation cost to the system operator before real-time. The regulator may watch over these activation costs to avoid market power issues in the balancing mechanism. To ensure that enough flexibility is available to balance the system, balancing capacity can be reserved. Reservations can be done through bilateral contracts or dedicated markets where power companies are the sellers and the only buyer is the system operator. System operators of zones with compatible market designs can buy balancing capacity in a unique market. These reservations may be performed on the long term e.g. one year, but will tend to be made on shorter terms, e.g. a week or a day ahead [13]. These contracts include a reservation cost aimed at covering the loss of opportunity resulting from the reservation. Keeping upward flexibility off the markets could prevent a power company from making profits when market prices are higher than the production costs of a reserved production unit. Reserving downward flexibility could impose a producer to produce at a loss if the electricity market prices are low. Note that power companies could also exchange their balancing capacity between them throughout the reserve market. In addition to contracted reserves, additional balancing capacity can usually be obtained on the short term. The regulation of some countries imposes on power companies to provide the flexibility that has not been sold in the energy markets to the system operator. In other countries, for instance Germany, the system operator may not rely on additional balancing capacities.

The system operator activates its available balancing capacity based on the current system imbalance and forecasts of future imbalances. The system operator does its best to activate balancing energy at the lower cost. The cheapest production unit is selected to provide upward balancing, while downward balancing is preferably obtained by decreasing the production of the most expensive asset. Taking the cheapest course may not be possible due to technical constraints and uncertainties on the future system imbalances. These activations have a cost which is transferred to the power companies via the imbalance settlement.

Before the neutralization delay, a power company communicates to the system operator its net position resulting from its exchanges with others. The imbalance of a power company is given by the difference between its realization and its net position over a given period. This period is called the imbalance settlement period. A positive imbalance, e.g. too much production, leads to a payment by the system operator to the power company proportional to the positive imbalance price. A negative imbalance, e.g. not enough production, leads to a payment by the power company to the system operator proportional to the negative imbalance price. These imbalance prices are a function of the total system imbalance and the balancing activation costs. These prices should be designed to minimize total system cost, usually by dissuading power companies from increasing the total system imbalance.

Note that the term “balancing” is quite broad reaching since it includes all efforts made by the actors of the system to balance it. The balancing not only includes the system operator but also power companies themselves which participates to the balancing of the system. This participation can be direct - via the activation of balancing energy, or indirect - via deviations from their net positions which can be intentional or not. Note that intentional deviations can be either help or hinder the system depending on the signal sent by the imbalance prices. A balancing mechanism should therefore be carefully designed to provide convenient signals. Survey [13] from the ENTSO-E provides a quick overview of the diversity in Europe of balancing mechanisms in 2015.

1.2. Structure of the model and objectives

The aim of this document is to present one method to model short-term electricity markets from exchanges that occur the day before to balancing activations and imbalance settlement. This model focuses on a single market zone, which generally corresponds to one country, neglecting losses and network constraints. Power companies interact with the day-ahead electricity market, the intraday market and the system operator by building market offers, providing their positions to the system operator and impacting the balance of the electric system. The energy market clears by maximizing the sum of the surpluses of the offers. The system operator activates balancing energy to restore the balance of the system, using all the available balancing capacity, including reserve, which changes the realization of the power companies. The cost of these activations defines the imbalance prices. These prices are part of the imbalance settlement mechanism creating bidirectional transactions between power companies and the system operator. Figure 2 depicts the structure of the interactions within the model.

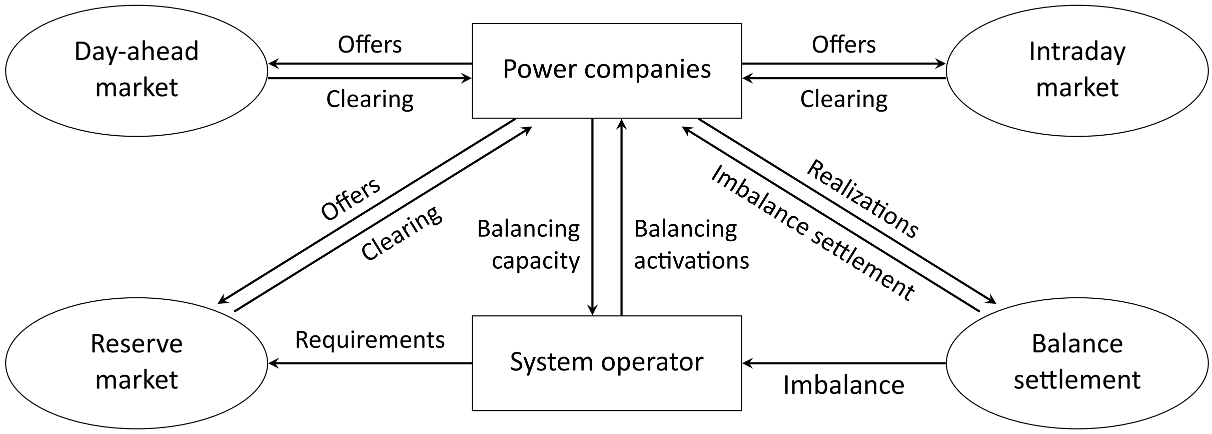


Figure 2: Overview of the interactions within the short-term electricity market model.

Time in the model is discretized into simulation time steps. Imbalances are often settled at a resolution of 15 minutes, which imposes to a simulation time step to cover at most 15 minutes. To integrate this constraint, the described model is developed to be flexible for resolutions going from one hour to five minutes. The resolution also acts as the smallest common divisor in the model. Imbalance settlement periods, intraday market periods and day-ahead market periods can all be expressed as sets of simulation time steps. One simulation with the model is performed by sequentially considering each time step of the horizon to be simulated, given the decisions taken in previous steps. An example of the situation at the simulation time step 12:00 of 15 minutes is presented in Figure 3. The clearings of intraday and day-ahead markets occur at 12:00 for energy delivered in future simulation time steps. Power companies may not change their production plan in the period 12:00-13:00. Further time steps are open to modifications of the schedule and power companies rely on planned schedules to build offers for intraday and day-ahead markets. Assuming a system operator acting, at most, half an hour in advance, the activation of balancing is performed in the period 12:00-12:30. In the model, since all information is known after the realization, the imbalance prices of the last imbalance settlement period are settled in the following simulation time step. Assuming an imbalance settlement period of a quarter of an hour, the imbalance prices between 11:45 and 12:00 are settled at the end of the time step 12:00.

This document breaks down the explanation of the model into three parts: energy markets models, the balancing mechanism model and the model of a power company. They are respectively described in Section 2, 4 and 3. The objective of building this model is first to understand the problems behind actions and decisions of the actors of the short-term electrical system. The second objective is to provide insights into how these problems can be solved. Usually the methods are complex and there is dedicated literature for most of the decisions to take in the electrical system. For instance, the clearing of the European day-ahead electricity market is itself the topic of numerous researches, e.g. [5, 27]. Unit

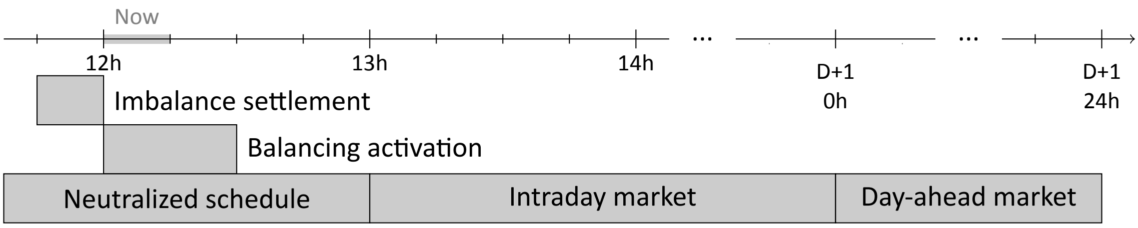


Figure 3: Impact of the actions taken at the simulation time step 12h of 15 minutes given a neutralization delay of one hour and a system operator activating balancing at most half an hour in advance.

scheduling is a very important element of the strategy of a producer and has become a renowned research topic for the operation research community, e.g. [36, 38, 45]. The third modeling objective is to see how the decisions are linked together in order to shape a coherent system. The links can be market offers, financial transactions, price signals, etc. In particular, building offers for the day-ahead market may not be straightforward since the products exchanged in this market cannot always accurately represent the constraints of some production units.

Once the model is built, the last objective can be achieved: assessing the impact of changing the short-term market design or the type of system i.e. the production mix, the number of power companies, etc. This is the topic of Section 5, which starts by analyzing the results of a simulated reference case and follows with sensitivity analyses of various parameters of the model and market design.

1.3. Literature review

Many electricity market models exist; see [22] for a detailed review. This section reviews models which focus on the short-term European electricity markets. Table 1 provides a quick overview of the models reviewed in this paper, as well as *SiSTEM*, the one described in this paper. They are divided in two categories: the optimization models (OM) and the agent-based models (ABM). The table focuses on a limited number of particularities. For instance, there is no need to mention that all models integrate uncertainties. The check mark does not, however, reflect the quality of the modeling which is left to the discretion of the reader. The models are differentiated by the existence of an intraday model not necessarily including an intraday market, the presence of explicit market offers i.e. quantity and costs that are cleared to form a price, a procedure creating imbalance prices, and market zones with limited exchanges. A check mark in the transparency column is earned when a model publishes the equations and algorithms driving the behavior of the system, e.g. the optimization problems, the applied heuristics, etc.

Table 1: Comparison of short-term electricity market models.

Ref.	Name	Type	Intraday model	Market offers	Imbalance settlement	Market zones	Transparency
[40]	WILMAR	OM	✓		✓	✓	✓
[1]	stELMOD	OM	✓			✓	✓
[3]	METIS	OM	✓		✓	✓	✓
[2]		OM/ABM		✓		✓	✓
[29]		ABM		✓	✓		✓
[6]	PowerACE	ABM		✓		✓	✓
[4]	OPTIMATE	ABM	✓	✓	✓	✓	
	SiSTEM	OM/ABM	✓	✓	✓		✓

In optimization models, a benevolent planner runs unit commitment problems integrating all units in the system on a rolling horizon. These models are also called single-firm optimization models [41]. The value of the residual demand, i.e. the demand minus the non-dispatchable production, is updated at each simulation time step. The dual variables associated with the equality constraints between the production and the consumption are taken as approximation of market prices. The *WILMAR* model uses this procedure to obtain day-ahead, intraday and balancing volumes by performing a unit commitment over a 36-hour horizon rolling every three hours [40]. This model has shown that stochastic optimization results in less-costly, of the order of 0.25%, and better-performing schedules than deterministic optimization. Similar results are obtained with the *stELMOD* model on an illustrative application to the German power system, also using successive rolling horizon schedules [1]. The European Commission initiated the development of the energy modeling software *METIS* covering the European energy system for electricity, gas and heat at the hourly level [3]. To tackle the complexity of the problem, unit commitments are performed on clusters of production units and relaxed as linear programs. The model is able to simulate one year by optimizing a generation plan, including both energy generation and balancing reserve supply, based on day-ahead demand and renewable generation forecasts. Then, the generation plan is updated during the day, taking into account updated forecasts and technical constraints of the assets. Finally, imbalances are drawn to simulate balancing energy procurement and post-processing of the hourly schedule allows for the studying of balancing mechanisms.

In agent-based models, there is more than one power company and explicit market clearing procedures. Agent-based modeling is a common technique used to conduct quantitative analyses [39]. This technique does not require making strong simplifying assumptions to be able to represent the system analytically and to solve it [42]. The difference between an optimization model and an agent-based one has been estimated to 2.8% of the operating cost on a case study of the Central Western European system in favor of deterministic unit commitment procedure by a hybrid model [2]. Loads, renewable producers and certain thermal producers are modeled in this study as submitting continuous bids. Thermal generators are modeled as submitting large exclusive bid groups, one group per generator, containing a discretized version of their generation possibilities for the next day. An agent-based model has been used to quantify the impact of integrating retailers, controlling load flexibility with pay-back effect, in the day-ahead energy and reserve markets, and in imbalance settlement [29]. Market participants provide explicit balancing offers which are activated by the system operator to balance the system at least cost, leading to imbalance prices. The results show that the provision of reserves by flexible loads has a negligible impact on the energy market prices but markedly decreases the cost of reserve procurement of the studied system. The *PowerACE* agent-based model is more focused on long-term capacity expansion planning [6]. The model still simulates an hourly day-ahead market with limited interconnection capacities between market zones and determines the market outcome as well as power plants dispatch. In this model, supply and demand bidders provide basic offers to the day-ahead market, single period and no block offers. This model has been applied to analyze how cross-border congestion management and capacity mechanisms affect welfare and generation adequacy in Europe [35]. The *OPTIMATE* agent-based model integrates commercial actors and system operators. Simulations are run for a year at 30 to 15 minutes granularity, modeling day-ahead, intraday, real-time and ex-post processes. Commercial actors generate and submit bids to a market-coupling entity. The market-coupling entity conducts a net-transfer capacity-based or flow-based market coupling in order to compute the accepted bids and offers. The intraday chain models successive half-hourly actions by the transmission system operator and commercial actors followed by the imbalance settlement process. An ex-post learning module enables commercial actors to improve their price forecasts, and to conduct an inventory of hydro energy available for the hydro dams. Among other studies, the *OPTIMATE* model has been used to show that there is more generation curtailment using explicit balancing, i.e. using bids, than with implicit balancing, i.e. communicating the characteristics of the production assets [9]. *OPTIMATE* seems to be the most complete model of the state of the art, yet lacking a public detailed description including the implementation details such as the optimization problem solved by the commercial actors, the market clearing algorithm, the method to build their market offers, etc.

This paper presents in detail the *SiSTEM* model, for Simulation of Short-Term Electricity Markets, providing the mathematical problems influencing the decisions of all modeled actors. Even though the model simulates multiple independent agents, no learning is used throughout the simulation. SiSTEM belongs to the category of the simulation models according to the classification of [41], but not of the agent-based one. This model is a unique combination of the strengths of previous models aiming at precisely modeling short-term markets, with special care paid to balancing mechanisms and the constraints influencing their outcomes. In *SiSTEM*, each power company with its specific portfolio performs complex unit commitment at a 15-minute granularity. The assets handled are thermal units, hydro-electric reservoirs and curtailable production. The thermal unit model not only integrates traditional ramping constraints, the start-up/shut down phase and minimum on and off times but also notification delays inherent to many thermal units and steady-state constraints. See Section 7.1 providing the optimization model of thermal units for more details. Interaction with the day-ahead market, the intraday market and the system operator are conducted via bids which may be multi-period with partial acceptance, or not, and linked with other bids. The offers-building strategy of power companies can either be portfolio-based or unit-based. The influences of all the modeling specifics of SiSTEM are quantified in the results of Section 5.

2. ENERGY MARKETS MODELS

This section begins the description of SiSTEM, starting with the energy market models. Energy markets are responsible for matching purchases and sales. An offer is communicated as a bid b, consisting in a cost γ_b in €/MWh and quantities $q_{b,t}$ in MWh for each market period t. A single market period offer has only one $q_{b,t}$ which is nonzero. By convention, purchases are represented by positive quantities and sales by negative quantities. Similar to what is done in practice, the quantities are rounded to avoid numerical issues. In this model, the quantities are rounded to the closest integer leading to a minimum exchange of 1 MWh. Note that, the minimum volume on the EPEX day-ahead energy market is 0.1 MWh. Additional constraints may be added to these bids and are implemented in this model. In this document, binary bids correspond to bids constrained to a binary decision, accept everything or nothing. A bid may be restricted to be accepted only if another binary bid is accepted. These bids are respectively named child and parent bid. The model could be extended to all other type of offers and constraints. For instance, the European day-ahead energy market integrates many more different products [17].

2.1. Day-ahead energy market

The European day-ahead energy market clears the day before the delivering day. Typically, the gate closure for submitting bids occurs at 12:00 and results are provided one hour later. The clearing of the market aims at maximizing the global welfare of the market. In this model, the clearing is formulated using a primal-dual formulation inspired from [27] and [2]. The actual day-ahead market clearing is based on a branch-and-cut algorithm named Euphemia [17]. The optimization problem solved in SiSTEM is the following:

Sets

$\mathcal{B}$	Bids
$\mathcal{B}^b$	Binary bids
$\mathcal{C}$	Child bids
$\mathcal{C}(b)$	Child bids of block bid $b \in \mathcal{B}^b$
$\mathcal{T}$	Market time steps

Parameters

γ_b	Cost of bid b
M_b	Modeling constant to prevent accepted offers with negative surplus.
$q_{b,t}$	Volume of bid b in time step t
$[\pi^{\text{min}}, \pi^{\text{max}}]$	Market price range

Selling bids take positive quantities and buying bids take negative quantities.

Variables

x_b	Acceptance of bid b
π_t	Market price of time step t
s_b	Surplus of bid b

Optimization problem

$$\max \sum_{b\in\mathcal{B}} \gamma_b x_b \sum_{t\in\mathcal{T}} q_{b,t} \tag{1a}$$

subject to

$$\sum_{b\in\mathcal{B}} q_{b,t} x_b = 0 \qquad \forall t \in \mathcal{T}\ [\pi_t] \tag{1b}$$

$$x_b \leq 1 \qquad \forall b \in \mathcal{B}\ [s_b] \tag{1c}$$

$$x_{b_2} \leq x_{b_1} \qquad \forall b_1 \in \mathcal{B}^b, b_2 \in \mathcal{C}(b_1)\ [s_{b_2}] \tag{1d}$$

with $x_b \in [0,1], \forall b \in \mathcal{B} \setminus \mathcal{B}^b$; $x_b \in \{0,1\}, \forall b \in \mathcal{B}^b$; and

$$s_b + \sum_{t\in\mathcal{T}} \pi_{\zeta_b,\tau_b} q_{b,t} \geq \gamma_b \sum_{t\in\mathcal{T}} q_{b,t} \qquad \forall b \in \mathcal{B} \setminus \mathcal{B}^c \tag{1e}$$

$$s_b + \sum_{t\in\mathcal{T}} \pi_{\zeta_b,\tau_b} q_{b,t} - \sum_{b_2\in\mathcal{C}(b)} s_{b_2} \geq \gamma_b \sum_{t\in\mathcal{T}} q_{b,t} + M_b(1 - x_b) \qquad \forall b \in \mathcal{B}^b \tag{1f}$$

$$\sum_{b\in\mathcal{B}} \gamma_b x_b \sum_{t\in\mathcal{T}} q_{b,t} \geq \sum_{b\in\mathcal{B}\setminus\mathcal{C}} s_b \tag{1g}$$

with $\pi_t \in [\pi^{\text{min}}, \pi^{\text{max}}], \forall t \in \mathcal{T}$; $s_b \in \mathbb{R}^+, \forall b \in \mathcal{B}$.

The formulation (1) is a primal-dual formulation where the primal problem is given by (1a)-(1d). The objective function (1a) maximizes the welfare. The equality between accepted purchases and sales is enforced by constraint (1b). Constraint (1d) enforces the link between bids.

The dual part of the formulation (1e)-(1g) allows one to define the prices in the same optimization problem. The dual variables associated to each primal constraint are given in brackets within the primal problem. The price in a market period is given by the dual variable associated to the balance constraint (1b). The surplus of a non-binary bid is defined by inequality (1e). Note that if the bid is linked, this surplus is decreased by the price of its link with its parent. The surplus of a binary bids is given by inequality (1f) which includes the possibility to reject an offer if accepting it leads to a negative surplus. This possibility requires one to take the constant M_b large enough, e.g. $M_b = (\pi^{\text{max}} - \pi^{\text{min}}) \sum_{t\in\mathcal{T}} |q_{b,t}|$. The equality of the primal and dual objective function of the day-ahead energy market is ensured by (1g).

2.2. Intraday market

In most European countries, the real intraday market is a continuous market where offers are updated continuously by the market participants. In this model, the intraday market is implemented by market sessions taking place every simulation time step. The intraday market is cleared using optimization problem (1). Note that the latter problem is flexible with respect to the number of market periods or their duration. After the clearing of the day-ahead market, the intraday market opens for the next day, e.g. at 19:00. In every simulation time step, the intraday market first clears the opened intraday market period. For instance, the clearing at 8:00 clears the period from 9:00 to 24:00 of the same day. The one occurring at 20:00 clears the period from 21:00 of the current day to 24:00 of the next day. These procedures provide a price for each intraday period at each clear intraday market clearing. An indicative intraday price is built for a given delivery time step by taking the weighted average over the volumes exchanged in each intraday clearing, including the time step. At the end of the market session, the current intraday time step may include more than one simulation time step. Considering a half-hour-based intraday market, a product in this market covers two simulation time steps.

3. POWER COMPANY MODEL

Power companies are actors of the electrical system which manage the production units and the consumption. Each power company aims at maximizing its profit given its own portfolio of assets and clients. The model considers producers as power companies without consumption and retailers as power companies without production assets. To maximize their profits, power companies continuously update their schedules and offers in the markets. In the model, decisions are updated in each simulation time step in four phases: forecasting, dispatching, trading and communicating balancing capacity.

To make its decisions, a power company needs forecasts. For instance, forecasted exogenous quantities are the consumption and production from renewable energies such as wind, photo-voltaic or run-of-the-river hydro-electricity. Using its own forecasts, a power company decides which assets to use to produce the necessary energy to cover its consumption and sales. This scheduling phase is computationally challenging since it requires optimizing the output of each asset taking into account its constraints on a potentially large horizon. In practice, the schedule of the portfolio for a whole day does not change every minute, it would be too computationally demanding and would need too many human interventions. Scheduling is therefore divided into two parts in the model: short-term and long-term scheduling. They are both performed with the same resolution in this model, e.g. 15 minutes to study the impact of balancing. Short-term scheduling modifies the schedule of the assets over one or two hours and is performed in every simulation time step. Short-term scheduling is used to take into account the latest accepted intraday market offers, until the final schedule, and the activation of balancing. Long-term scheduling allows the integration of day-ahead market exchanges and aims at estimating how to satisfy the demand at the lowest cost in particular using assets with a lot of inertia. For instance, starting a coal production unit requires it running to keep for at least eight hours and its high start-up cost favors an even longer period. In the model, power companies perform long-term unit commitment before and after the opening of the day-ahead energy market, at the opening of the intraday market, and before and after the short-term reserve mechanism clearing and every four hours. The resulting production schedule describes how the power company intends to produce energy to satisfy its consumption and its exchanges. This schedule can be used as reference to compute how much the power company can increase its production and at what cost. This reference also provides the cost of energy production and therefore at which price the company is willing to buy energy to avoid using its own production assets. The reference therefore allows for the computing of the flexibility of the power company which can be either offered on the different markets or communicated to the system operator for balancing.

This section details how actions of a power company are modeled. The generation of forecasts feeding the scheduling model is detailed in Section 3.1. The general optimization model of units-scheduling is formulated in Section 3.2. The general method to obtain the flexibility of a production unit and to communicate it as offers for the day-ahead market, intraday market and balancing capacity procurement is described in Section 3.4. A portfolio-based alternative is given in Section 3.5. How this flexibility is proposed in the markets is detailed in Section 3.3. The specific models of the production assets are given in the Appendix. The model of thermal units is described in Section 7.1 and includes on-off status, ramping constraints, minimum on, off and steady-state time and notification delays. The hydro-electric reservoirs portfolio model is given in Section 7.2. The total stock is divided in a finite number of reservoirs with their own constraints. A total stock constraint links them together. The production cost is given by a stock value computed as a function of the stock level. Curtailable production is modeled in Section 7.3, with a maximum realization changing with the forecasts.

3.1. Forecasts

The target production schedule of a power company is given by the sum of its exchanges and forecasts of the consumption and the non-dispatchable production including, in particular, the renewable production. In this model, their predictions are generated from their realizations which are given as input to the model. The prediction error is modeled as evolving from a maximum error, obtained for a delay of T, to a minimum error in real-time. The maximum error signal is generated by taking a random signal around the realization, smoothed by convolution with a Hanning window. A forecast of minimum error is generated using the same method. In the implementation, the length of the default smoothing window used by a power company is given by $\lfloor W/10+4 \rceil$, where W is the number of simulation time steps per day.

The forecast error decreases with time, according to a logarithmic function, toward a forecast of minimum error, $\hat{p}_t^b$, given by a Gaussian law. The prediction evolves from the worst forecast $\hat{p}_t^w$ achieved in $t-T$ of the realization p_t, to the best forecast, $\hat{p}_t^b$ achieved in t. One last parameter provides the relative decay of the error σ, arbitrarily set by default to 0.05. This evolution is influenced by the constant T and σ such that the forecast of p_t in time step τ, $\hat{p}_t(\tau)$, satisfies for $\frac{t-\tau}{T} \in [0,1]$

$$\hat{p}_t(\tau) = \hat{p}_t^b + \frac{\hat{p}_t^w - \hat{p}_t^b}{\ln\left(\frac{1+\sigma}{\sigma}\right)} \ln\left(\frac{\frac{t-\tau}{T}+\sigma}{\sigma}\right). \tag{2}$$

The default parameters in the implementation define a maximum error of 10% obtained 16 hours before real-time that decreases to 3%. Due to the smoothing processes, the actual error obtained differs from these parameters. To give an order of magnitude, the generated forecast error in day-ahead of a consumption signal ranged from 0 to 9.53% with an average of 2.47%. The error one hour before real-time ranged from 0 to 1.94% with an average of 1.47%.

3.2. Units-scheduling and balancing strategy

The units-scheduling task is to coordinate the production of individual units to reach a coherent schedule Q_t at minimal cost. The target schedule Q_t includes the forecasts detailed in Section 3.1, the energy exchanged on the markets and the balancing activation of the system operator. This coordination is performed by solving the optimization problem (3), traditionally known as a unit commitment problem. Three particularities of this formulation are worth highlighting. First, problem (3) is solved by each power company independently to reflect the current practice in the European electrical system. The problem is not solved by the system operator which has no direct control over the production units. Second, the target power to produce may be different from the consumption, in particular to include exchanges with other market participants. Third, the solution may deviate from the target schedule. The importance and occurrence of these deviations depends on the balancing strategy of the power company. This strategy is defined by the parameters of the optimization problem as explained further in the section.

Sets

$\mathcal{S}$	Balancing periods
$\mathcal{T}$	Time steps
$\mathcal{U}$	Production units
$\mathcal{X}_i$	Production units constraints

Parameters

$C_i(\mathbf{p}_i)$	Cost function of the production unit
Δ	Length of a time step
E_t	Exogenous production
$L^+_{i,t}, L^-_{i,t}$	Upward and downward reference for important deviation
κ^+_b, κ^-_b	Upward and downward important deviation prices
μ^+_b, μ^-_b	Upward and downward imbalance cost
Q_t	Target power to produce
R^+_t, R^-_t	Upward and downward reserve of the portfolio

Variables

$b^+_{i,t}, b^-_{i,t}$	Upward and downward balancing capacity of a unit
D^+_t, D^-_t	Upward and downward deviations
I^+_t, I^-_t	Upward and downward imbalance
K^+_t, K^-_t	Upward and downward important deviation
$p_{i,t}$	Power output of a unit

To simplify the notation we use $\mathbf{p}_i = \{p_{i,t}, \forall t \in \mathcal{T}\}$ and $\mathbf{b}_i = \{b^+_{i,t}, b^-_{i,t}, \forall t \in \mathcal{T}\}$.

Optimization problem

$$\min \sum_{i \in \mathcal{U}} C_i(\mathbf{p}_i) - \sum_{s \in \mathcal{S}} \left(\mu^+_s I^+_s + \mu^-_s I^-_s \right) - \sum_{t \in \mathcal{T}} \left(\kappa^+_t K^+_t + \kappa^-_t K^-_t \right) \tag{3a}$$

subject to

$$(\mathbf{p}_i, \mathbf{b}_i) \in \mathcal{X}_i \qquad \forall i \in \mathcal{U} \tag{3b}$$

$$\sum_{i \in \mathcal{U}} p_{i,t} + E_t = Q_t + D^+_t + D^-_t \qquad \forall t \in \mathcal{T} \tag{3c}$$

$$I^+_s + I^-_s = \sum_{t \in s} (D^+_t + D^-_t)\Delta \qquad \forall s \in \mathcal{S} \tag{3d}$$

$$K^+_t \geq D^+_t - L^+_t \qquad \forall t \in \mathcal{T} \tag{3e}$$

$$K^-_t \leq D^-_t - L^-_t \qquad \forall t \in \mathcal{T} \tag{3f}$$

$$\sum_{i \in \mathcal{U}} b^+_{i,t} = R^+_t \qquad \forall t \in \mathcal{T} \tag{3g}$$

$$\sum_{i \in \mathcal{U}} b^-_{i,t} = R^-_t \qquad \forall t \in \mathcal{T} \tag{3h}$$

with $(p_{i,t}, b^+_{i,t}, b^-_{i,t}) \in \mathbb{R}^+ \times \mathbb{R}^+ \times \mathbb{R}^-, \forall (i,t) \in \mathcal{U} \times \mathcal{T}$; $(D^+_t, K^+_t, D^-_t, K^-_t) \in (\mathbb{R}^+)^2 \times (\mathbb{R}^-)^2$, $\forall t \in \mathcal{T}$; $(I^+_s, I^-_s) \in \mathbb{R}^+ \times \mathbb{R}^-$, $\forall s \in \mathcal{S}$.

The individual constraints of the production units are summarized by equation (3b) where for each unit i, $\mathbf{p}_i$ is the vector of power output through time and $\mathcal{X}_i$ the set of constraints specific to the unit. The details of $\mathcal{X}_i$ for each type of production unit are available in the Appendix. Power balance is ensured by equality (3c), also computing the deviation in each time step. The deviation is defined as the difference in one simulation time step between the target schedule and the solution schedule. Equation (3d) defines an imbalance as the average of the deviations over an imbalance period. Balancing strategy may be refined by defining important deviations, i.e. deviations above a given threshold, as expressed by (3e)-(3f). The objective function jointly minimizes production and imbalance costs and penalizes important deviations. The reserve that the power company must provide is dispatched between the units of its portfolio using the coupling constraints (3g)-(3h).

The balancing strategy of the actor, i.e. the compromise the actor makes between following its schedule and relying on the imbalance mechanism, is determined by the following parameters. The upward and downward imbalance costs, μ_s^+, μ_s^-, quantify the financial incentive for the power company to balance itself. For instance, if the downward imbalance cost is lower than a production cost, the solution of the optimization problem favors a deviation. However, the power company will avoid important deviations assuming the prices set for them are important. A deviation is qualified as important if it is respectively above or below the reference powers L_t^+ and L_t^-.

Two different balancing strategies are implemented: a no-imbalance strategy and a price-based strategy. In the first one, imbalance prices forecast which are used by the power company in its unit commitment are very conservative, which corresponds to a risk-averse behaviour. Before the clearing of the day-ahead market the forecasts are set to 3000 €/MWh for a downward imbalance and -3000 €/MWh for an upward imbalance. In the intraday, the company uses pessimistic values of the imbalance prices, arbitrarily set to 300 €/MWh for a downward imbalance and -1 €/MWh for an upward imbalance.

The second balancing strategy is a more risk-taking one. In this intentional-imbalance strategy, the power company use the current imbalance prices as reference for its forecasts if the current system imbalance is significant. An imbalance is considered significant if it is larger than 50% of the system operator balancing requirements and the imbalance is increasing. This 50% is the default parameter of a power company and can change in function of the simulated instance. For the next hour and half, the power company uses the current positive and negative imbalance prices, π^{i+} and π^{i-}, the current system imbalance I to compute the parameters of the balancing strategy as follows:

$$\mu_b^+ = \pi^{i+} - \chi|\pi^{i+}| - 1 \tag{4a}$$
$$\mu_b^- = \pi^{i-} + \chi|\pi^{i+}| + 1 \tag{4b}$$
$$L_t^+ = \max\{I/20, -I/4\} \tag{4c}$$
$$L_t^- = \min\{I/20, -I/4\} \tag{4d}$$

where χ is the relative mixed-integer programming gap tolerance used to solve the optimization problem (3).

3.3. Energy markets interactions

In the model, offers to the day-ahead market are submitted in the time step right before the clearing of the market. These offers can be built unit-based or portfolio-based. The two strategies are respectively described in Sections 3.4 and 3.5. In either case, the reference schedule considered is obtained by performing an initial units-scheduling where the power company satisfies its own consumption using its production units. The portion of the production or consumption which is not covered by the units is offered to the day-ahead market as buying or selling offers at a cost corresponding to the forecast of the imbalance price, see Section 3.2. Other alternatives could be considered, such as taking a zero reference which may imply buying its own production on the market to satisfy its own consumption. A more complex one would be to predict the volume that will be traded on the day-ahead market and add them to the consumption to obtain a centered reference around the most likely market settlement.

Offers to the intraday market are built unit-based since it concerns significantly smaller volumes and therefore may be more impacted by the minimum production constraint of some production units. A power company also needs to take into account the time needed to adjust its schedule once the offer is accepted. Therefore, availability of offers depends on the neutralization delay and the notice delay of the production unit if relevant. In the implementation, if any time step of an intraday market period is neutralized in the next simulation time step, the power company makes no offers in this market time step. Any unit with a notice delay increases this effect by the corresponding amount of simulation time step.

3.4. Unit-based offers

To interact with the markets, a power company needs to be able to compute the flexibility of a given unit with respect to its reference schedule. The time horizon on which this flexibility is computed depends on the target market. The following details the generic method to compute the flexibility of a unit in a given time step on any trading period. The trading period can include more than one trading time step and consequently many simulation time steps. Specific applications to the different markets are specified afterwards.

The unit-based flexibility module is responsible for providing a list of bids valid on the trading period for a given unit. The following explains the process to build bids for upward flexibility. The process to obtain downward flexibility offers is symmetric. The quantity of available upward flexibility for unit i is obtained by taking the difference between the reference schedule $\mathbf{p}_i$ and the maximum production of the unit $\mathbf{p}_i^+$. This maximum depends on the schedule outside of the trading period and can be obtained by solving the following optimization problem.

Sets

$\mathcal{H}$	Trading time steps
$\mathcal{X}_i$	Production units constraints

Parameters

$p_{i,T^{\text{start}}}$	Scheduled power output in the time step before the first trading time step
$p_{i,T^{\text{end}}}$	Scheduled power output in the time step after the last trading time step
$b_{i,t}^+, b_{i,t}^-$	Upward and downward balancing capacity of the unit

Variables

$p_{i,t}^+$	Power output of a unit

To simplify notation, we use $\mathbf{p}_i^+ = \{p_{i,t}^+, \forall t \in \mathcal{T}\}$ and $\mathbf{b}_i = \{b_{i,t}^+, b_{i,t}^-, \forall t \in \mathcal{T}\}$.

Optimization problem

$$\max \sum_{t\in\mathcal{H}} p_{i,t}^+ \tag{5a}$$

subject to

$$p_{i,T^{\text{start}}}^+ = p_{i,T^{\text{start}}} \tag{5b}$$

$$p_{i,T^{\text{end}}}^+ = p_{i,T^{\text{end}}} \tag{5c}$$

$$(\mathbf{p}_i^+, \mathbf{b}_i) \in \mathcal{X}_i \tag{5d}$$

with $p^{+}_{i,t} \in \mathbb{R}, \forall t \in \mathcal{T}$. The initial power output of the unit is defined by (5b). Equality (5c) imposes that the unit returns to its schedule after the trading period. Finally, (5d) impose that the modulation satisfies the unit constraints recycling the unit model $\mathcal{X}_i$ defined in scheduling problem (3).

The flexibility of a production unit is given by the difference between the initial schedule and the alternative schedule. By default, the flexibility in each trading time step is offered as in independent bid which can be partially accepted at a cost equal to the variable cost of the production unit. Particularities of offers building for each type of production units is detailed in their respective section in the Appendix. In particular, thermal production units require making block offers, offers covering more than one trading time step, and links between the offers.

3.5. Portfolio-based offers

Portfolio-based offers are generated based on a predefined number of generation scenarios. The algorithm is composed of the following steps. First, it performs three units-scheduling with three different targets: minimum production, maximum production and getting as close as possible to the reference scenario. Intermediate scenarios are then generated in between these three scenarios, twenty additional scenarios by default. Units-scheduling in these scenarios provides the closest possible volumes and the associated costs. Theses volumes and costs are then divided into individual offers for each market time step. The reference scenario is considered as a base to define the flexibility offers and is arbitrarily set to the forecast of the consumption. Volumes above this reference are converted into selling offers. The difference in volume between the first scenario above the reference and the reference volume is offered at the difference of total cost between the two scenarios divided by the difference of volume over the whole horizon. The process is repeated for the next scenarios taking the difference with the previous ones. Sales are generated using the symmetric process. Note that this algorithm only generates bids on single trading periods that can be partially accepted. No blocks are generated by this procedure. The target schedule resulting from the clearing of the energy market may be difficult to follow by the production assets' portfolio. This bidding strategy is therefore optimistic compared to the possibility granted by the dynamic constraints of the production units. For this reason, the portfolio-based flexibility is meant to be used by power companies controlling a sufficiently large portfolio of production units.

4. BALANCING MECHANISM MODEL

This section details the balancing mechanism from the point of view of the system operator. The model focuses on the balancing energy from the frequency restoration reserve and the replacement reserve. The implemented reserve mechanisms are described in Section 4.1. Section 4.2 describes the forecast of the future imbalances of the system. The activation process of the balancing capacity is described in Section 4.3 and the following imbalance settlement in Section 4.4.

4.1. Balancing reserve procurement

Balancing reserve procurement rules differ from one European country to another. Different types of reserve, i.e. manual or automatic frequency restoration reserves or replacement reserves, are contracted with different delays [13]. For instance, Spanish automatic frequency restoration reserves and replacement reserves are contracted on the day-ahead. French manual frequency restoration reserves and replacement reserves are contracted one year ahead. Reserve obligations are often contracted with an actor and may be the object of bilateral exchanges with other power companies as long as they are certified by the system operator. Currently, short-term reserves in Europe are mostly contracted via organized markets which may still lead to bilateral contracts [13]. The rules used by system operators to define their capacity requirements change from one system to another. Review [30] provides a comparison of operating practice of system operators.

In this model, two mechanisms are implemented to model balancing reserve procurement. The simplest is long-term unit-based reserves included in the model as a mandatory capacity to be able to be produced or consumed by a given unit. Power companies include these volumes as constraints when providing the schedule of their unit. The amount of reserve is an input parameter of the model. The system operator considers that reserves should be as available for activation on a single balancing period and can be partially activated without any notification delay.

The second implementation is a day-ahead balancing reserve procurement. This variant is also equivalent to modeling the results of a long-term portfolio-based reservation followed by bilateral exchanges between producers. The reserved capacities provided by each power company are obtained by an iterative process where the system operator reserve requirements are given as parameters. In an iteration, the system operator sets upward and downward reserve prices. Given these prices and the reserve requirements, power companies communicate the reserve they are willing to provide. If this reserve is below the requirements, reserve prices are increased, otherwise they are decreased. The minimum reserve price is set to 1 €/MW/h. With a price of 0 €/MW/h in this model, power companies would have no incentive to propose their flexibility to the system operator and instead keep it for themselves.

The day-ahead reserve prices definition process can be seen as a black-box optimization problem with important discontinuities. These discontinuities mainly come from the start-up constraint of thermal units. If the reserve price allows one to cover the start-up cost of a unit scheduled to be off, all its remaining capacity becomes available as reserve. Algorithm 1 describes one procedure to define the upward reserve price for a given reserve time step. It takes as parameters the required capacity of reserve R and the default reserve price increment α, e.g. 50 €/MW/h. The extension to multiple time steps and downward reserve is straightforward and omitted for clarity and conciseness. This algorithm is inspired from the pattern search method tuned to this problem, in particular to deal with the discontinuities and the necessity to reach the reserve requirements. This process may be computationally expensive since it requires at each iteration for each power company to compute a schedule. To maintain reasonable computation efforts, the maximum number of iteration is set to 20 with a tolerance of 10 MW on the reserve capacity and a 2 €/MW/h tolerance on the reserve prices are used to stop iterating.

procedure Reserve prices($\mathbf{R}, \boldsymbol{\alpha}$)
    $k, \boldsymbol{\lambda}, \mathbf{V}^0, \leftarrow 1, \mathbf{1}, \mathbf{0}$ ▷ Initial iteration, reserve prices and volumes
    while $k \leq$ Maximum number of iterations **do**
        $\mathbf{V}^k \leftarrow \sum_{a \in \text{power companies}} \text{reserve}(a, \boldsymbol{\mu})$ ▷ Compute reserve obtained from prices
        for all $t \in$reserve periods **do**
            $\alpha_t \leftarrow \alpha_t/2$ **if** $\left|R_t - V_t^k\right| \leq \left|R_t - V_t^{k-1}\right|$ **else** $1.5\alpha_t$ ▷ Update price variation
            $\lambda_t \leftarrow \lambda_t + \alpha_t$ **if** $V_t^k < R_t$ **else** $-\alpha_t$ ▷ Update reserve price
        end for
        $k \leftarrow k + 1$
    end while
end procedure

Algorithm 1: Reserve market price definition algorithm from the required reserve volume R and a default reserve price increment α.

To participate in the modeled short-term reserve market, a power company needs to provide reserve quantities corresponding to reserve prices. These quantities may be obtained by solving a modified version of problem (3). The modified version (6) aims at determining the quantities of reserve R_t^+, R_t^- for each reserve time step t based on the reserve prices λ_t^+ and λ_t^-. These quantities are restricted by the maximum amount that could be bought by the system operator $\overline{R}^{?} +_t, \underline{R_t^-}$.

Sets

$\mathcal{S}$	Balancing periods
$\mathcal{T}$	Simulation time steps
$\mathcal{T}^r$	Reserve time steps
$\mathcal{U}$	Production units
$\mathcal{X}_i$	Production units constraints

Parameters

$C_i(\mathbf{p}_i)$	Cost function of the production unit
Δ	Length of a simulation time step
E_t	Exogenous production
$L^+_{i,t}, L^-_{i,t}$	Upward and downward reference for important deviation
λ^+_t, λ^-_t	Upward and downward reserve prices
κ^+_b, κ^-_b	Upward and downward important deviation prices
μ^+_b, μ^-_b	Upward and downward imbalance cost
$\overline{R}^+_t, \underline{R}^-_t$	Maximum upward and minimum downward reserve to provide
Q_t	Target power to produce

Variables

$b^+_{i,t}, b^-_{i,t}$	Upward and downward balancing capacity of a unit
D^+_t, D^-_t	Upward and downward deviations
I^+_t, I^-_t	Upward and downward imbalance
K^+_t, K^-_t	Upward and downward important deviation
$p_{i,t}$	Power output of a unit
R^+_t, R^-_t	Upward and downward reserve of the portfolio

To simplify the notation we use $\mathbf{p}_i = \{p_{i,t}, \forall t \in \mathcal{T}\}$ and $\mathbf{b}_i = \{b^+_{i,t}, b^-_{i,t}, \forall t \in \mathcal{T}\}$.

Optimization problem

$$\max \sum_{t\in\mathcal{T}^r} \left(\lambda^+_t R^+_t - \lambda^-_t R^-_t\right) - \sum_{i\in\mathcal{U}} C_i(\mathbf{p}_i) + \sum_{s\in\mathcal{S}} \left(\mu^+_s I^+_s + \mu^-_s I^-_s\right) + \sum_{t\in\mathcal{T}} \left(\kappa^+_t K^+_t + \kappa^-_t K^-_t\right) \tag{6a}$$

subject to

$$(\mathbf{p}_i, \mathbf{b}_i) \in \mathcal{X}_i \qquad \forall i \in \mathcal{U} \tag{6b}$$

$$\sum_{i\in\mathcal{U}} p_{i,t} + E_t = Q_t + D^+_t + D^-_t \qquad \forall t \in \mathcal{T} \tag{6c}$$

$$I^+_s + I^-_s = \sum_{t\in s} (D^+_t + D^-_t)\Delta \qquad \forall s \in \mathcal{S} \tag{6d}$$

$$K^+_t \geq D^+_t - L^+_t \qquad \forall t \in \mathcal{T} \tag{6e}$$

$$K^-_t \leq D^-_t - L^-_t \qquad \forall t \in \mathcal{T} \tag{6f}$$

$$\sum_{i\in\mathcal{U}} b^+_{i,t} \geq R^+_t \qquad \forall t \in \mathcal{T}^r \tag{6g}$$

$$\sum_{i\in\mathcal{U}} b^-_{i,t} \leq R^-_t \qquad \forall t \in \mathcal{T}^r \tag{6h}$$

with $(p_{i,t}, b^+_{i,t}, b^-_{i,t}) \in \mathbb{R}^+ \times \mathbb{R}^+ \times \mathbb{R}^-, \forall (i,t) \in \mathcal{U} \times \mathcal{T}$; $(R^+_t, R^-_t) \in [0, \overline{R}^+_t] \times [\underline{R}^-_t, 0], \forall t \in \mathcal{T}^r$; $(D^+_t, K^+_t, D^-_t, K^-_t) \in (\mathbb{R}^+)^2 \times (\mathbb{R}^-)^2$, $\forall t \in \mathcal{T}$; $(I^+_s, I^-_s) \in \mathbb{R}^+ \times \mathbb{R}^-$, $\forall s \in \mathcal{S}$.

4.2. System imbalance forecast

A proactive system operator needs to forecast the future system imbalances to take proactive actions. These forecasts must capture the needs to activate block offers ahead of time for major imbalances, while preventing as much as possible the need for costly counter-activation afterwards. Note that one important component of the imbalance is the forecast error. Therefore, forecasting imbalance roughly corresponds to forecasting a forecast error which should, by construction, be zero on average. In this model, the system operator directly forecasts the balance of the whole system rather than forecasting the consumption as in section 3.1 and subtracting the planned production. The system operator builds a scenario tree around the trend of observed system imbalances. The observed imbalances not only include the sum of forecast errors of the actors, but also outages, differences between schedules and exchanged energies due to the minimum volume accuracy of energy markets, etc. This scenario tree is used in the balancing activation process described in Section 4.3.

A scenario tree of system imbalance forecasts is built in two steps. First, a most credible scenario is predicted. Many methods can be used to define a most credible scenario such as taking a 0 future imbalance, unchanged imbalance or linear regression as depicted in Figure 4. The default method used in this model is to take the average of the past imbalances. This baseline is adapted with the outages information to improve the accuracy of the forecast. Based on this most credible scenario, two others are generated: one above and one below the most credible. Based on these three scenarios, the scenario tree is built by creating, for each node, at most three children corresponding to the three base scenarios. This procedure is illustrated in Figure 4. From the system imbalance realizations, the system operator generates a trajectory of system imbalance given by the dotted line in the example. Based on this trajectory, the system operator generates two additional scenarios, one above and one below, to capture credible deviations. The implementation arbitrarily places them at 75% and 125% of the base trajectory. The black lines represent the links between the nodes of the scenario tree. Note that a node in Figure 4 may correspond to multiple nodes in the scenario tree since past actions must be taken into account.

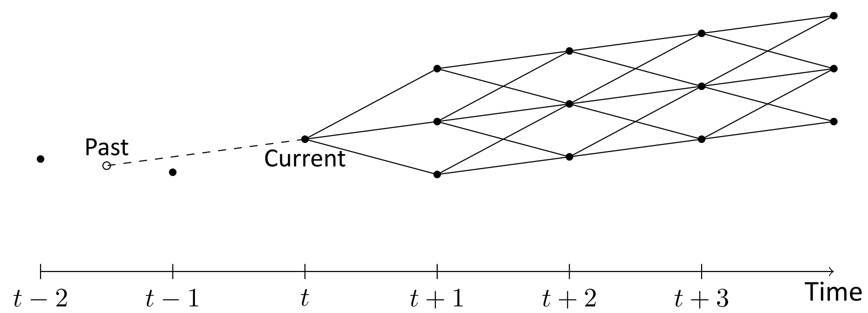


Figure 4: Forecast of the future system imbalance as a scenario tree.

4.3. Balancing activation

Knowing the current system imbalance, the system operator selects the flexibilities to activate from the available balancing capacity. To make its decisions, the system operator considers their impact on the future time steps of the system. The maximum horizon on which the system operator can activate balancing energy is named the operational window. A system operator only acting in one balancing period is named reactive since it only observes the current imbalance and activates the opposite energy volume. A proactive system operator first forecasts imbalance scenarios then activates balancing energy based on decisions taken previously. Note that this is also valid for decisions taken in the future. Decisions taken for three time steps further depend on the ones taken two time steps before now. Note the plural which implies that there are multiple decision states in one time step and their dependence must be handled by non-anticipatory constraints.

Power companies communicate all the flexibility resulting from their schedule to the system operator and the corresponding activation cost in the following simulation time steps. In this model, this flexibility is communicated as bids similar to the day-ahead and intraday markets. Activation of bids is subject to various constraints. Binary decisions, links and exclusions need to be considered. In practice, this complexity is ignored by some system operators and only basic products are considered. An additional constraint imposes a notification delay before the activation of some bids. These delays are communicated by the power companies to integrate reaction delays and constraints of their production units. An additional constraint is added to this model for offers named "security bids". These bids are limited to be used only in the opposite direction of the predicted system imbalance. For instance, a nuclear production unit can provide a reserve if its set point is not altered by much. The balancing capacity coming from the reservation of such units should therefore only be used for security purposes.

Power companies also communicate the outages of their thermal production plants: the missing energy production and the outage's duration. The duration is capped by the neutralization delay since the actor is responsible for changing its schedule or buying the missing energy on the markets outside of the neutralized period. The implementation takes a time series of outages as input described by the notification time, the duration and the maximum availability of the unit. If a unit is producing and faces a partial outage, the production of the unit decreases to a maximum available power given as a parameter.

The objective of the system operator in this phase is to balance the system at least cost. This obviously implies activating the upward flexibility with the least cost and the downward flexibility with the highest cost. The system operator may therefore perform economic counter-activations i.e. activate two bids that cancel each other out if the downward cost is higher than the upward cost. The latter may be prevented in some countries and in the model. The default choice in the implementation is to allow the system operator economic counter-activations, therefore improving the economic efficiency of the system. Note that counter-activations are not always economic and can come from the compensation of proactive actions taken using a bad forecast of the system imbalance.

Optimization problem (7) provides the decisions of balancing activations similar to what a decision support tool could provide, see for instance [28].

Sets

$\mathcal{B}$	Bids
$\mathcal{B}^b$	Binary bids
$\mathcal{B}^a$	Security bids
$\mathcal{L}$	Links between bids $(b_1, b_2) \in \mathcal{B}^b \times \mathcal{B}$ such that activation of b_1 is mandatory to activate b_2
$\mathcal{E}$	Activation exclusive bids $(b_1, b_2) \in \mathcal{B}^b \times \mathcal{B}^b$
$\mathcal{N}$	Nodes of the scenario tree
$\mathcal{N}_t$	Nodes of the scenario tree in time step t
$\mathcal{N}_{n,t}$	Children of node n in time step t
$\mathcal{T}$	Time steps
$\mathcal{T}_0$	Time steps except the current one

Node 0 corresponds to the root of the scenario tree.

Parameters

$A(n,k)$	Ancestor node $\in \mathcal{N}$ of node n of degree k. The parent of node n is $A(n,1)$.
β_b	Activation cost
κ	Penalty of the predicted residual imbalance of the system
κ_0	Penalty of the residual imbalance in the root node of the scenario tree
I_n	Total imbalance of the system
M_t^+, M_t^-	Maximum upward and downward available balancing capacity for activation
ω_n	Probability of a node
$q_{b,t}$	Volume of bid $b \in \mathcal{B}^b$ in time step t
τ_b	Activation time step of a bid b
v_t	Activated balancing volume by previous decisions

Upward capacities are taken positive and represents an increase of the production or a decrease of the consumption. Downward capacities are given by negative volumes.

Variables

i_n^+, i_n^-	Residual upward and downward imbalance of the system
b_n^+, b_n^-	Activated upward and downward balancing volume
$y_{b,n}$	Activation of bid b in node $n \in \mathcal{N}_{\tau_b}$

Optimization problem

$$\min \sum_{b\in\mathcal{B}} \left(\beta_b \sum_{t\in\mathcal{T}} q_{b,t} \sum_{n\in\mathcal{N}_{\tau_b}} w_n y_{b,n} \right) + \kappa_0 \left(i_0^+ - i_0^- \right) + \kappa \sum_{n\in\mathcal{N}\setminus\{0\}} w_n \left(i_n^+ - i_n^- \right) \tag{7a}$$

subject to

$$b_n^+ = \sum_{b\in\mathcal{B}:\tau_b\leq t, q_{b,t}>0} q_{b,t} y_{b,A(n,t-\tau_b)} \qquad \forall t \in \mathcal{T}, n \in \mathcal{N}_t \tag{7b}$$

$$b_n^- = \sum_{b\in\mathcal{B}:\tau_b\leq t, q_{b,t}<0} q_{b,t} y_{b,A(n,t-\tau_b)} \qquad \forall t \in \mathcal{T}, n \in \mathcal{N}_t \tag{7c}$$

$$b_n^+ + \min\{0, I_n\} \leq -M_t^- \qquad \forall t \in \forall t \in \mathcal{T}_0, n \in \mathcal{N}_t \tag{7d}$$

$$- b_n^- + \min\{0, -I_n\} \leq M_t^+ \qquad \forall t \in \forall t \in \mathcal{T}_0, n \in \mathcal{N}_t \tag{7e}$$

$$I_n + b_n^+ + b_n^- + v_t = i_n^+ + i_n^- \qquad \forall t \in \mathcal{T}, n \in \mathcal{N}_t \tag{7f}$$

$$y_{b_2,n_2} \leq y_{b_1,n_1} \qquad \forall (b_1,b_2) \in \mathcal{L}, (n_1,n_2) \in \mathcal{N}_{\tau_{b_1}} \times \mathcal{N}_{\tau_{b_2}} \tag{7g}$$

$$y_{b,A(n,t-\tau_b)} = 0 \qquad \forall t \in \mathcal{T}, n \in \mathcal{N}_t, b \in \mathcal{B}^n : q_{b,t} I_n > 0 \tag{7h}$$

$$\sum_{b\in\mathcal{B}^a:q_{b,t}>0} q_{b,t} y_{b,A(n,t-\tau_b)} \leq -I_n \qquad \forall t \in \mathcal{T}, n \in \mathcal{N}_t : I_n < 0 \tag{7i}$$

$$\sum_{b\in\mathcal{B}^a:q_{b,t}<0} -q_{b,t} y_{b,A(n,t-\tau_b)} \leq I_n \qquad \forall t \in \mathcal{T}, n \in \mathcal{N}_t : I_n > 0 \tag{7j}$$

$$y_{b_1,n_1} + y_{b_2,n_2} \leq 1 \qquad \forall (b_1,b_2) \in \mathcal{E} : \tau_{b_1} \leq \tau_{b_2}, n_1 \in \mathcal{N}_{\tau_{b_1}}, n_2 \in \mathcal{N}_{n_1,\tau_{b_2}} \tag{7k}$$

$$y_{b_1,n_1} + y_{b_2,n_2} \leq 1 \qquad \forall (b_1,b_2) \in \mathcal{E} : \tau_{b_1} > \tau_{b_2}, n_2 \in \mathcal{N}_{\tau_{b_2}}, n_2 \in \mathcal{N}_{n_2,\tau_{b_1}} \tag{7l}$$

with $y_{b,n} \in [0,1], \forall b \in \mathcal{B}^c, n \in \mathcal{N}_{\tau_b}$; $y_{b,n} \in \{0,1\}, \forall b \in \mathcal{B}^b, n \in \mathcal{N}_{\tau_b}$ and $i_n^+, i_n^- \in \mathbb{R}^+ \times \mathbb{R}^-, \forall n \in \mathcal{N}$.

Objective (7a) minimizes the activation costs while minimizing the remaining imbalance of the system. The default parameter for the penalties of the remaining imbalance are set to the imbalance price cap except for the root node, arbitrarily chosen at 20000 €/MWh. This choice of parameters expresses that ensuring the balance in the current time step is critical for security. On the other hand, the other nodes are predictions and could not become a realization. Making this difference is particularly important if the solver is stopped before reaching the optimal solution. The upward and downward activated balancing volumes in node n are computed by (7b) and (7c). Constraints (7d)-(7e) limit the balancing volumes activated in future time steps to avoid large counter activations. The implementation arbitrarily chooses M_t such that at least 25% of the available balancing capacity and the minimum balancing requirements cannot be counter-activated. The residual system imbalance is computed by (7f). The links between bids are enforced by inequality (7g). Security bids may not be activated in the same direction as the imbalance of the system by constraint (7h). If these bids are in the same direction, constraints (7i)-(7j) also restrict the activated volume to be less than the forecasted imbalance.

4.4. Imbalance settlement

A legal entity responsible for the balance of its intakes and off-takes is called a balancing responsible party [12]. In this model, each power company is considered as its own balancing responsible party. In practice, multiple power companies may form a single balancing responsible party. Balancing activation costs and revenues are redistributed among the balancing responsible parties, power companies in this model, proportionally to their imbalance volume. This imbalance volume is given by the difference between the realization of the balancing responsible party and its net position. The net position is computed by the balancing responsible party and communicated to the system operator at the neutralization delay. This position should correspond to the result of its exchanges with other market participants. A power company producing all the necessary energy to satisfy its consumption would therefore have a zero net position. A power company receives money if it produces more than its net position and pays out if it produces less than its net position. The amount of money received or paid is proportional to the positive and negative imbalance prices respectively. The volume of imbalance is defined by the energy difference between the net position and the realization. The latter net position corresponds to the position of the actor directly resulting from its commercial exchanges of flexibility at the neutralization delay before real-time. The imbalance volume is corrected by the system operator with the balancing activations which are not considered as imbalances. This energy difference is computed by averaging the power difference over an imbalance settlement period. For instance, Figure 5 shows an imbalance settlement over two simulation time steps.

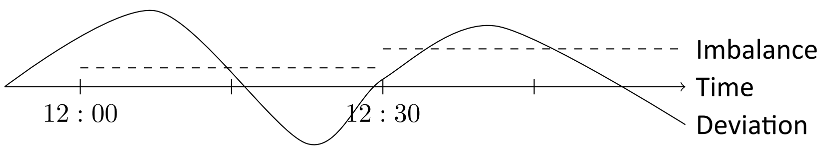


Figure 5: Definition of the imbalance by averaging the average deviation of an actor over an imbalance settlement period of half an hour.

Imbalance prices are computed in the model at the end of each imbalance settlement period. In practice, there can be a delay before the publication of these prices. Imbalances may be invoiced months later and gradually corrected over the year with the collection of electricity meter data. There are two main categories of imbalance settlement mechanism: single and dual pricing. In a single price imbalance settlement, positive and negative imbalance prices are equal and depend on the cost of activated balancing assets. In a dual price imbalance settlement, the imbalance price for power companies penalizing the system is a function of the cost of activated balancing assets, whereas the price for power companies helping the system is a function of the day-ahead market price. Table 2 provides one imbalance settlement rule used by the French system operator. Note that this rule corresponds neither to a single price nor a dual price imbalance settlement. Each column corresponds to one state of the system: long with more injections than off-takes and short with less injections than off-takes.

Imbalance price	System balance	
	Long	Short
Positive	min $\left(A^{-}\left(1-k\right), A^{-}\left(1+k\right)\right)$	min $\left(A^{+}\left(1-k\right), A^{+}\left(1+k\right)\right)$
Negative	max $\left(A^{-}\left(1-k\right), A^{-}\left(1+k\right)\right)$	max $\left(A^{+}\left(1-k\right), A^{+}\left(1+k\right)\right)$

Table 2: Imbalance settlement rule used by the French system operator where A^{+} and A^{-} respectively are the upward and downward average weighted cost of the activated balancing assets and k a coefficient defined to balance incomes and expenditures from balancing actions.

5. RESULTS

This section presents results on a fictive base case presented in Section 5.1. The results of its simulation are given in Section 5.2. The sensitivity of the results with respect to the simulation bias is evaluated in Section 5.3. In the other result sections, a limited number of parameters are changed to evaluate their impact. Sections 5.4 - 5.6 compare different market designs or quantify the impact of relaxing one modeling assumption. Additional results are presented in Appendix 8. Table 3 provides a summary of the parameters changed in the results with respect to the base case. These results only aim at illustrating the capabilities of the model. To provide accurate and detailed messages on market designs, one would need to perform more than one simulation per studied case. Since the outputs of such simulations are numerous and very detailed, the results focus only on noteworthy changes. Time series, such as prices or imbalance volumes, are described by their median, to be more robust to outliers, and their standard deviation.

The model is implemented in Python 3 using the Pyomo library [25]. The simulations are performed on a computer equipped with an Intel Xeon CPU E5-2697 v3 at 2.6 GHz, 64 GB of RAM, Python 3.5.2 and CPLEX 12.6 with a time limit for each optimization problem of 600 seconds and a mixed-integer gap tolerance of 5%, except for energy market clearings which are solved to optimality.

5.1. Description of the base case

Production assets and the consumption are managed by four different power companies. Actor 1 is a producer and a retailer operating all the nuclear power plants and the majority of hydro-electric reservoirs' capacity. Actor 2 is a producer and a retailer operating a coal power plant and two combined-cycle gas turbines and a small capacity of hydro-electric reservoirs. Actor 3 is a retailer with no generation asset and actor 4 a renewable energy producer. Their market shares are given in Table 4. All offers provided by the power companies are unit-based except the offers built by actor 1 for the day-ahead market which is assumed to rely on portfolio bidding. All power companies use the risk-averse balancing strategy described in Section 3.2.

Capacities of Table 4 are divided into production units following the parameters of Table 5. Variable costs are consistent with [26]. Start-up costs of nuclear plants are inferred from reference [37]. Other values, in particular constraints' parameters, are arbitrary choices taken for illustrative purposes and can differ significantly from actual values. There are two types of nuclear plants, two of combined-cycle gas turbines (CCGT), one of open-cycle gas turbine (OCGT) and one small-size coal power plant. Variable costs of the units are drawn from 5%-wide uniform distribution around values given in Table 5. The parameters of their outages are given in Table 6. The deratings correspond to outages adequate for the scale of the system, i.e. 300 MW. The variable cost of the renewable production is arbitrarily set to zero.

Dispatchable hydro-electric production from reservoirs is divided into two parts, the manually-controlled one and the remote-controlled one. The only difference between the two is the delay of notice which is

Table 3: Summary of the parameters changed in each subsection of the results.

Case	Parameters			System			Markets				Actors behavior	
	Number of runs	Time resolution	Neutralization delay	Types of constraints	Level of uncertainty	Number of power companies	Day-ahead	Intraday	Balancing	Short-term reserve	Market offer types	Balancing strategy of the actors
• Main results (Section 5)												
5.2 Base case	1	15 minutes	15 minutes	All	Forecast errors and outages	4	1 hour products	15 minute products	Reactive SO	No market for reserves	Unit-based except portfolio-based DAM offers from actor 1	No-imbalance
5.3 Simulation bias	20											
5.4 Steady state constraints and delay of notice				No steady state constraint and delay of notice								
5.5 Time and portfolio resolution of the DAM							15 minute products				Unit-based for all	
5.6 Short-term balancing reserve procurement										Market for reserves		
• Addtional results (Appendix B)												
8.1 Hourly resolution		1 hour										
8.2 Benevolent monopoly						1						
8.3 Perfect forecast					No uncertainty							
8.4 Absence of intraday market								No intraday market				
8.5 Price-based actor balancing												Actor 1: price-based
8.6 Proactive system operator			1 hour						Proactive SO			

Table 4: Distribution of the capacity between the actors of the studied case in MW.

Type	Actor 1	Actor 2	Actor 3	Actor 4
Nuclear A	1300			
Nuclear B	1720			
CCGT A		400		
CCGT B	200	200		
OCGT	360			
Coal		300		
Remote reservoir	320	100		
Manual reservoir	80			
Photovoltaic				260
Wind				500
Consumption	[-3840, -2138]	[-768, -428]	[-512, -285]	
Run-of-the-river	[114.2, 287.2]	[28.6, 71.8]		
Cogeneration	62.6	11.4		

respectively of three hours and five minutes. Their infeeds and bounds are taken from French historical data and scaled to match the installed capacities given in Table 4. The bounds on the stock supplies ensure a coherent management of the reservoirs on the long term. The average hourly infeed of the reservoirs is 116 MWh. Their stock values may vary between 20 and 120 €/MWh with an average sensitivity of 0.283 c€/$(\text{MWh})^2$. The economic impact of the final stock variation of the hydro-electric reservoirs in the total system cost is computed using 50 €/MWh in all scenarios. This allows making the results less dependent on the variable stock value of hydro-electric reservoirs while preserving the management strategy of the water in the simulation. Note that the variable cost of the reservoir is zero in practice if considered in a long-term model. In this short-term model, it is necessary to include the cost of releasing more water since it will not be available later, i.e. outside of the simulated time horizon. A scenario releasing more water should therefore be seen as more costly than another.

The remote-controlled hydro-electric production is imposed to provide 150 MW of upward reserve, 120 MW and 30 MW respectively provided by actors 1 and 2. In practice, nuclear power plants have a limited flexible capacity around its steady-state operation point. See reference [34] for a discussion on the technical flexibility of modern nuclear power plants. In this base case, nuclear A provides up to 11.5% of its maximum power, corresponding to 150 MW, for downard reserve without any constraints. In the following, this flexibility is referred to as flexible nuclear to differentiate if from a shift of operational point. The capacities of Table 5 lead to a system of 9 thermal production units for a total of 14 controllable production units.

Table 5: Parameters of the thermal units.

Type	Variable cost	Startup cost	Power range	Ramp rate	On time	Off time	Steady period	Notice delay
	€/MWh	*k€*	*MW*	*MW/h*	*h*	*h*	*min*	*min*
Nuclear A	10	325	[250, 1300]	2400	72	24	120	30
Nuclear B	12	225	[180, 860]	1800	72	24	120	30
CCGT A	28	21.5	[180, 400]	1020	4	4	15	15
CCGT B	30	10	[100, 200]	1020	4	4	15	15
OCGT	150	7.2	[125, 180]	720		0.5	15	
Coal	20	30	[150, 300]	210	8	8	60	45

The time series used to model the consumption and production from run-of-the-river hydroelectricity, cogeneration, photovoltaic and wind are taken from historical chronicles of France in 2014 scaled to

Table 6: Outage parameters of the thermal units.

Unit	Yearly occurrence	Duration	Derating
	%	h	%
Nuclear B	5	7	25
CCGT A	5	3	50
CCGT B	5	3	100
Coal	7.5	7	50

$1/20$. The numbers given in Table 4 are the range of values taken by the time series and the installed capacities for the photovoltaic and wind productions. Forecasts for each of these time series are generated as explained in Section 3.1. Figure 6 shows the individual error of each actor at the clearing of the day-ahead market, one hour ahead and 15 minutes ahead. These forecasts lead to a system forecast errors on the day-ahead of 3.06% with a maximum of 11.84%, and 1.18% in real-time with a maximum of 6.03%. This forecast error is indirectly observed by the system operator via its imbalance forecast described in Section 4.2.

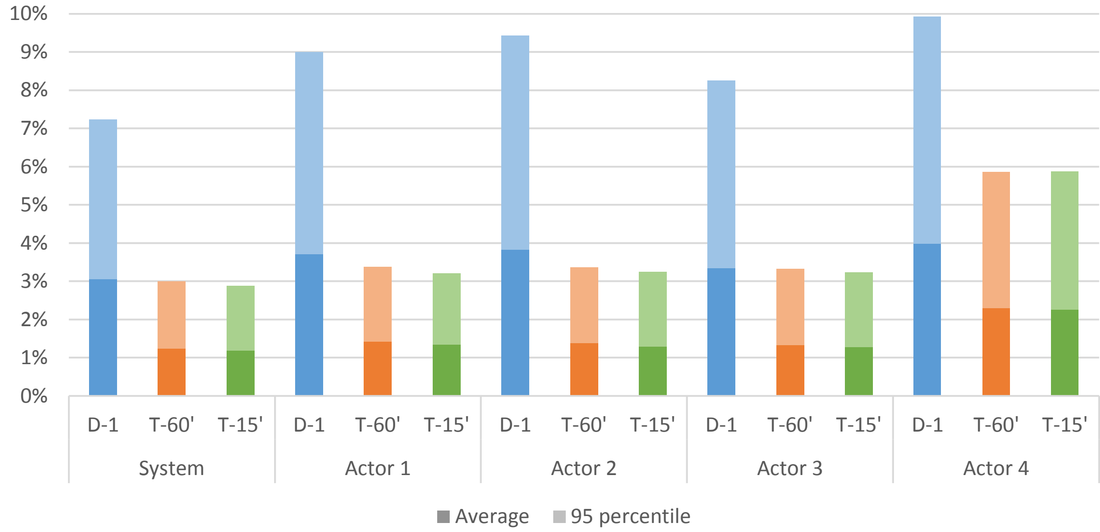


Figure 6: Relative forecast errors.

The system is simulated over 32 consecutive days representing January. Each day is divided into 96 simulation time steps. The day-ahead market divides the next day into 24 market periods. The intraday market resolution is set to 15 minutes. The system operator is reactive, i.e. only activates balancing in the current 15 minutes simulation time step. There is no short-term reserve mechanism. The neutralization delay is set to 15 minutes. The imbalance prices are computed according to the average single price imbalance settlement mechanism described in Section 4.4 and the parameters given in Table 2. For conciseness, results only provide one imbalance price measure which corresponds to the average of the positive and negative imbalance prices.

5.2. Results from the simulation of the base case

Results are obtained after 15 hours of computation. The energy shares of each production technology and the corresponding average production costs are given in Table 7. The variable costs provided in this table include startup costs. For most types of production unit, these costs are close to their variable costs. OCGT units make the exception with predominant startup costs since they are mostly used in brief production peaks. Figure 7 shows the top part of the realization of the production since 78% of the produced energy is provided by nuclear plants. Nuclear plants are mostly producing at their maximum capacity but still reduce their production by 15% to 30% during the night and at the week-end.

Table 7: Breakdown by production technology of the energy share and short-term production costs.

	Energy share	Average cost [€/MWh]
Nuclear	77.56%	10.80
CCGT	9.46%	31.76
Coal	6.21%	20.52
Hydro	2.11%	50.00
Renewable	4.53%	
OCGT	0.13%	242.22
Average	3837 MWh/h	14.03 €/MWh

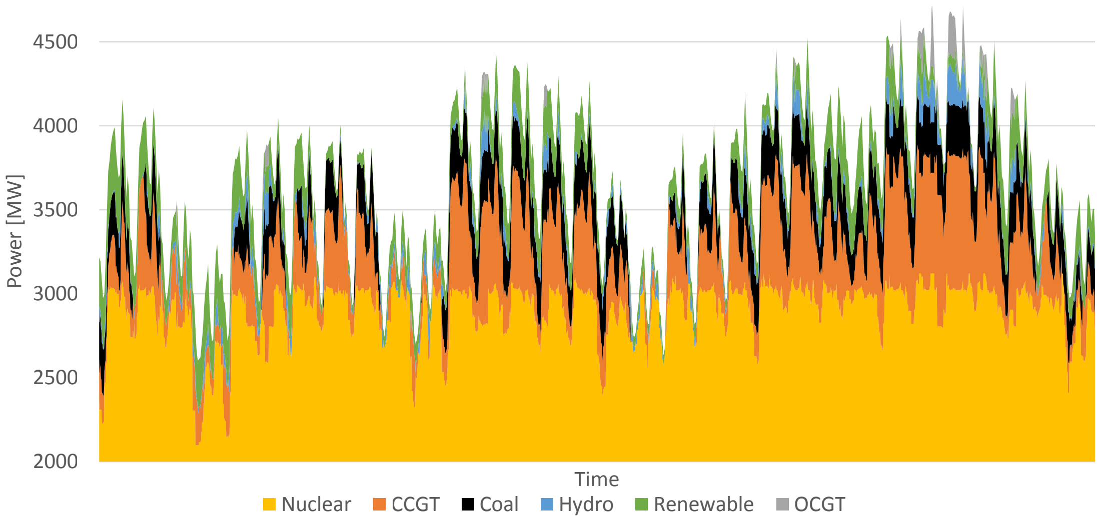


Figure 7: Zoom on the realization throughout the simulated month of the production divided per technology.

The median of volumes exchanged per hour in the day-ahead market is 570 MWh with a standard deviation of 149 MWh. This corresponds to 15% of the average production. This rate is low since most of the consumption belongs to the portfolio of power companies owning production assets. This rate is of the same order of magnitude as the 21% reached in 2016 by France on EPEX which includes exports [16]. The median day-ahead market price is 26.59 €/MWh with a standard deviation of 11.48 €/MWh. The median of intraday exchanges per hour is 136 MWh, 3.5% of the average production, with a standard deviation of 83 MWh. The standard deviation magnitude shows the high volatility of this intraday market which is confirmed by the median price of 28.69 €/MWh with a standard deviation of 20.72 €/MWh. The median imbalance price is 41.06 €/MWh with a standard deviation of 28.74 €/MWh. The 8% difference between the upward and downward prices comes from the coefficient k as detailed in Table 2. Over the month, there are ten balancing periods where the imbalance price reaches 400 €/MWh. This value corresponds to the marginal cost of running an OCGT for a single quarter which ranges from 385 to 550 €/MWh taking into account the startup costs. Balancing is mainly provided by the flexible nuclear production and the remote-controlled hydro-electric reservoirs. OCGTs are mostly used in this model for downward balancing in the simulated scenarios. A typical scenario is when actor 1 dispatches an OCGT plant to balance itself and that the system requires less production than anticipated. As a result, the system operator requires downward balancing from the OCGT. Curtailment of renewable energy only happens in four 15' time steps for downward balancing of approximately 20MW from wind turbines during the night. The model allows the system operator to perform economic counter-activations i.e. activate two bids that cancel each other out if the downward cost is higher than the upward cost, see Section 4.3. These counter-activations sum up to 12% of the balancing energy. They mainly take the form of an energy transfer between the reservoirs of actors 1 and 2 when their stock values differ. The balancing activation could be modeled to be less sensitive to economic counter-activations by changing the activation costs.

Figure 8 shows how exchanges in the day-ahead and intraday markets impact the net position of the power companies. Actor 1 is the main seller in the day-ahead market since it owns the cheapest production units. Most of the time, actor 2 is a buyer on the day-ahead market. Actor 3 is a pure retailer which buys the totality of its energy on the day-ahead market. Actor 4, possessing the renewable energy production, only sells on the day-ahead market. Actors 3 and 4 still exchange small quantities on the intraday market which correspond to their forecast updates. In intraday, Actor 1 buys energy from actor 2 which possesses the CCGTs with a cheaper flexibility than the hydro-electric reservoirs. The median stock value obtained over the month is 43.22 €/MWh with a standard deviation of 8.15 €/MWh. Energy provided for balancing represents 30% of the hydro-electric reservoirs production.

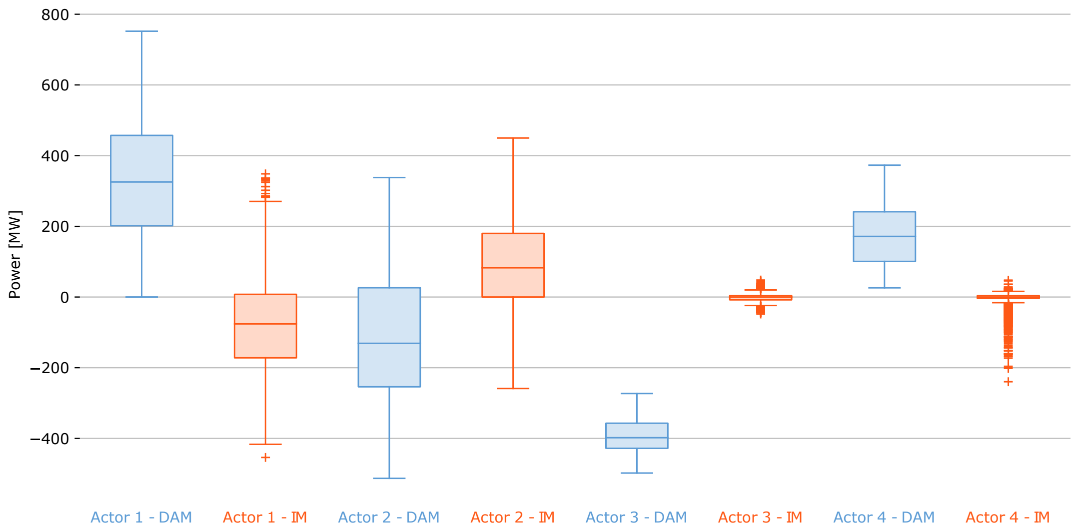


Figure 8: Box plot of the net exchanges in the day-ahead market (DAM) and intraday market (IM) where positive quantities represents energy to be produced by the power company.

The day-ahead and intraday markets, as well as the balancing mechanism, allows for using block bids and links between blocks. In the development of the model, those blocks imposed themselves as necessary to properly communicate the constraints of thermal units. In the day-ahead market, 27 of the submitted bids where blocks or linked bids corresponding to 6.3% of the total number of bids and 10% of the volume. In intraday, there are 115 linked bids per day accepted with 35 pure blocks. They only represent 6.3% of the total number of bids but sum up to 32% of the energy exchanged. The balancing capacity counts 369 linked bids per day on average, which represents 23% of the communicated capacity. On average, only 4% of the activated balancing energy corresponds to linked bids. There are five days over the simulated month where the energy covered by the linked offers reaches more than 10% of the total energy activated.

5.3. Simulation bias

To obtain results in a reasonable amount of time but still be robust with respect to difficult optimization problems, the mixed-integer linear programs are solved with a tolerance of 5% and a time limit of 600 seconds. This introduces some randomness in the results which must be quantified. The sources of this randomness are the heuristics used by the solver, the parallelization of the branch-and-bound algorithm, etc. The instance of Section 5.2 is simulated twenty times. The aim is to determine the minimum variation of an indicator to be significant with respect to the simulation bias. Table 8 provides the difference between the maximum and the minimum values observed divided by the average value of the medians and standard deviations of different time series of instance simulated several times. Note that these biases are very pessimistic since they are based on the worst recorded difference.

Table 8: Maximum bias of the medians and standard deviations of time series for the same instance simulated twenty times.

Accuracies	Median	Std. deviation	Unit
Day-ahead price	0	2.54	*€/MWh*
Day-ahead volume	31	15.9	*MWh*
Intraday price	0.93	5.25	*€/MWh*
Intraday volume	28.55	22.16	*MWh*
Imbalance price	12.33	5.33	*€/MWh*
Imbalance	1.04	1.86	*MW*
Reservoirs stock value	10.55	1.18	*€/MWh*

The running time ranges from 14 to 17 hours to simulate the same month under the same conditions. The average production cost ranges from 13.95 to 14.16 €/MWh with an average of 14.04 €/MWh, which leads to a maximum bias of 1.5%. The average daily total revenues of actor 1 have a similar maximum variation of 1.56%. The median day-ahead price is identical in each of the twenty simulations. The median is less affected by outliers and is therefore used for the analysis of the results. The average day-ahead market price has a bias of 5% or 1.29 €/MWh. The medians of day-ahead and intraday prices and volumes are very reliable with a less than 5% error. The median imbalance prices may change by 20% which is the consequence of very volatile reservoir stock values, by approximately the same amount. The maximum difference of energy production from the reservoirs is 8.8% explaining the difference of reservoir stock values. This difference comforts the choice of setting the economic impact of the final stock variation at a constant value and not at the computed variable stock values. Stock values are not taken constant in the simulation since the computed value impact the strategy of the actors. For instance, if balancing volumes decrease then the production from reservoirs also decreases and stock values need to decrease in order to be able to sell the additional reservoirs stock supply in energy markets.

5.4. Steady-state constraints and delays of notice

In this scenario, steady-state constraints are ignored as well as delays of notice. The two constraints are grouped together since they are often ignored in the literature. This section shows why they are compulsory to correctly model balancing and how they impact the total cost.

Ignoring these two constraints reduce the computation time by 30% to 10 hours. The average production cost decreases by 2.7% to 13.65 €/MWh. This decrease is the result of a 3.42% decrease of the production costs from CCGTs, 0.78% from hydro-electric reservoirs and 0.48% from coal units compensated by an increase of 1.42% in nuclear production costs. The median day-ahead market price decreases by 5.64% to 25.09 €/MWh. The median intraday price also decreases by 7.2% to 26.62 €/MWh.

The volumes of imbalance barely change between the base case and the one using the relaxed thermal model since the main causes of imbalances are forecast errors and outages of thermal units. The technologies used for balancing are given in Figure 9. Neglecting the notification delays and the steady-state constraints allows CCGT to provide 30% of the balancing energy. Standard nuclear production is able to provide 15% of the upward balancing energy. The contribution of upward balancing of the hydro-electric reservoirs reduces to 45%. The contribution to downward balancing of reservoirs is less affected by the relaxation of the model. This results in a diminution of the energy production from the reservoirs of 11% leading to a median hydro-electric stock value of 30.50 €/MWh i.e. 30% less than in the base case. This price allows one to sell the hydro-electric stock supply in the day-ahead energy market in competition with CCGTs. 22% of the balancing energy comes from economic counter-activations, which explains the 10% increase of the activated balancing volumes with respect to the base case.

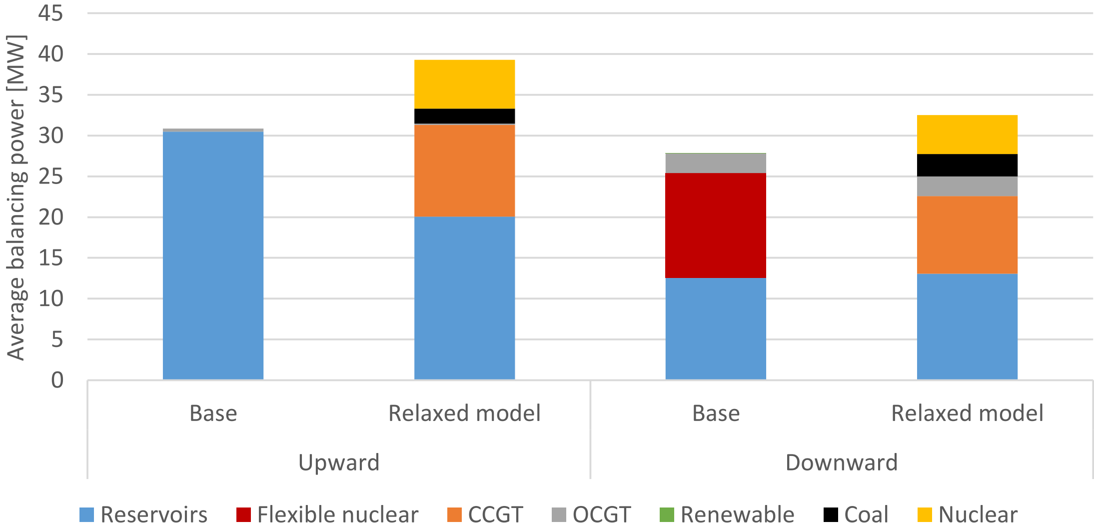


Figure 9: Share of each technology in the upward and downward balancing activations in the base case and with a relaxed thermal model neglecting steady-state constraints and delay of notice.

5.5. Time and portfolio resolution of the day-ahead market

This section evaluates the impact of two parameters: the resolution of the day-ahead market and the strategy used by actor 1 to build its offers. In the base case, the day-ahead market clears 24 market periods and actor 1 provides portfolio-based offers.

In the first scenario, the resolution of the day-ahead market is set to 15 minutes and actor 1 still provides portfolio-based offers. The simulation results show no difference of the median volume exchanged in the day-ahead market or the prices with respect to the base case. The same assessment for the intraday market shows that the difference in resolution is not the main cause of the intraday exchanges in this model. There is no impact on the imbalance volumes or prices since the outcomes of the energy markets are identical.

The strategy used by the power companies to build market offers is identical to the base case of Section 5.2. In particular, actor 1 provides portfolio-based offers as described in Section 3.5, i.e. single market period offers which can be partially accepted. One could wonder what the result of a simulation with unit-based day-ahead market offers from actor 1 might be. The portfolio-based strategy is used in the base case by actor 1 since it has a large and flexible portfolio of units which allows for reducing the impact of dynamic constraints on its schedule. This solution is optimistic compared to the possibility granted by the dynamic constraints of the production units. On the other hand, the unit-based strategy detailed in Section 3.4 is pessimistic since it does not include combinations of units. The influence of a portfolio-based or unit-based strategy used by actor 1 to compute offers for the day-ahead market is given in Figure 10. The total energy exchanged in the intraday market decreases by 20% in the unit-based case. The revenues from the day-ahead market of actor 1 increases with the portfolio-based strategy. This increase is equally compensated by the revenues from the intraday market. Day-ahead market prices resulting from the unit-based strategy are more volatile with the same median but a standard deviation of 186.9 €/MWh instead of 11.48 €/MWh in the base case. This high standard deviation is the result of various negative prices and price peaks above 150 €/MWh. This is the consequence of the large number of blocks that results from the unit-based strategy. Our simulation leads to four-times more linked bids on average than with the portfolio-based strategy. Note that the number of blocks is limited in the current day-ahead market as well as the number of links between the blocks [19]. The unit-based solution is less realistic to be used in practice in the day-ahead market for this reason and motivates the use of the portfolio based strategy for the base case.

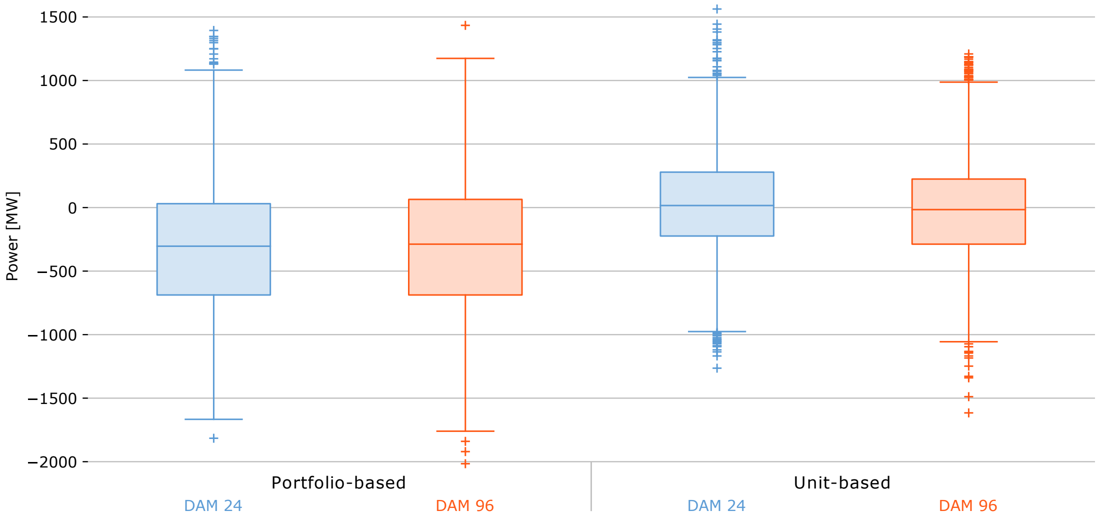


Figure 10: Box plot of the intraday exchanges of actor 1 using the unit-based or the portfolio-based strategy in a day-ahead market (DAM) of 24 or 96 periods.

5.6. Short-term balancing reserve procurement

Instead of imposing the unit-based reserve procurement in the long-term, this scenario uses the short-term reserve mechanism described in Section 4.1. The reserve procurement occurs at 17:00 for the next day. With the given parameters, only reservoirs, the flexible nuclear production and OCGTs are eligible as reserve capacity. Renewable production is arbitrarily prevented due to the high uncertainty that may result from its forecast. Reserve requirements are symmetric and given by the maximum between 4% of the consumption and 10% of the renewable production for a median requirement of 159 MW with a standard deviation of 19.5 MW.

This reserve is provided by the portfolios of actors 1 and 2. Actor 1 provides 72% of the upward reserve and 93% of the downward one. The resulting reserve prices are given in Figure 11. The average upward price is 6.09 €/MW/h. The upward reserve price is at its minimum, 1 €/MW/h, 92% of the time. The average price over the remaining hours is 67.29 €/MW/h. There are a few hours where the price goes above 100 €/MW/h and even one where the price reaches 350 €/MW/h driven by the startup of OCGTs. The rest of the time, OCGTs are already idle and are therefore able to provide reserves without the need to modify the original schedule. The average downward reserve price over the month is 12.58 €/MW/h which is higher than the upward one. This means that the production units able to provide reserves are not producing in the initial schedule. Usually the hydro-electric reservoirs are not producing in the initial schedule. One method to provide reserve is to decrease the nuclear or CCGTs production and replace it by hydro-electric production. Downward reserve prices are different from the minimum price in 56.51% of the hours with an average of 21.49 €/MW/h, which corresponds to the average cost of performing this switch.

Results show that the average production cost is not significantly affected by the short-term reserve mechanism compared to the base case where the flexible nuclear production and a part of the hydro-electric reservoirs provide constant reserves. There is no significant change in the prices and exchanges from the day-ahead energy market. The median intraday price decreases from 28.69 €/MWh to 28.02 €/MWh even if this variation is of the order of magnitude of the simulation bias. The imbalance signal, imbalance prices and stock values of the hydro-electric reservoirs are nearly identical. In the studied system, the results of using the long-term or the short-term reserve mechanism does not significantly impact the final production schedule. However, the approach quantifies the reservation cost at a resolution of one hour which could be used to calibrate a long-term reservation price.

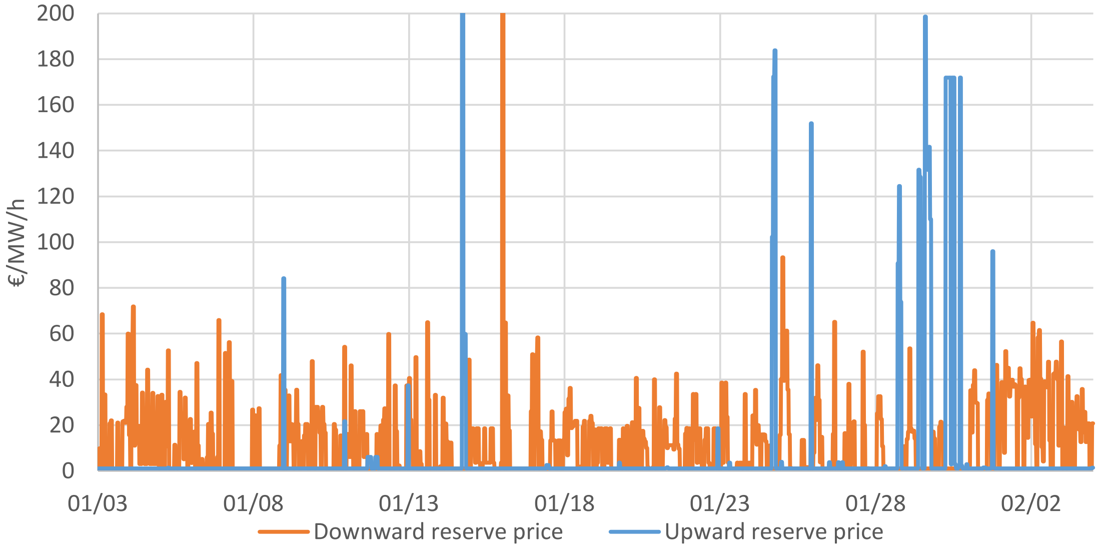


Figure 11: Hourly short-term reserve prices.

6. CONCLUSION

This paper details the implementation of *SiSTEM*, a model for the Simulation of Short-Term Electricity Markets. This model embeds an end-to-end representation of short-term electricity markets in a single market zone from exchanges that occur the day before real-time to balancing activations and imbalance settlement, providing the mathematical problems influencing the decisions of all actors. Power companies interact with the day-ahead electricity market, the intraday market and the system operator. The latter procures short-term reserve, activates balancing capacities and defines the imbalance prices. This model aims at accurately representing short-term electricity markets, with special attention paid to balancing mechanisms and the production assets constraints influencing their outcomes. Each power company, with its specific portfolio, performs complex unit commitments at a 15-minute granularity. The assets handled by the model are thermal units, hydro-electric reservoirs and curtailable renewable production. The thermal unit model integrates traditional unit-commitment constraints, start-up/shut down phases, and minimum on and off times. The model is enhanced by taking into account notification delays inherent to many thermal units and steady-state constraints. Interactions with the day-ahead market, the intraday market and the system operator are conducted via bids which may be multi-period with partial acceptance or not, and may be linked between them. The offers-building strategy of power companies can either be portfolio-based or unit-based. To the best of our knowledge, no articles in the literature which provide an efficient and accurate strategy to create flexibility offers from a schedule of a portfolio of units using different market products such as block bids and links between blocks. This paper details two strategies of power companies to build block offers for the energy markets or to communicate their balancing capacities.

The objective of developing this model is to understand the consequences of decisions made by competitive actors in the short-term, to provide insights on how these problems can be solved, and to see how the decisions are linked together in order to shape a consistent power system. Running this model allows for conclusions to be validated on study cases, taking into account the underlying hypotheses, as is the case with all simulation models. Results presented in this paper only aim at illustrating the capabilities of the model and are obtained from the simulation of a fictive instance. Conclusions could be different in other scenarios, for instance with an increased share of renewable energy, less nuclear production capacity, or different parameters for the flexibility of thermal units.

Compared to single firm optimization models, multi-actor simulation models and in particular *SiSTEM*, allows for analyzing prices, exchanges between the actors and their strategies. In particular, the model provides insightful intraday price approximations, shows how the exchanges depend on the portfolio of the actors, and allows for assessing different strategies of balancing, market offer construction, etc. For instance, traders could be implemented in this model and their impact quantitatively assessed.

Another particularity of *SiSTEM* is to model the system at a sub-hourly resolution. A comparison with an hourly resolution shows the importance of detailed thermal constraints on intraday exchanges and balancing activations. Among these constraints, the delay of notice before making changes and the minimum time in steady-state operation have a significant impact on the results. These constraints also impact the offers proposed in the different markets. In the simulated scenario, 32% of the volumes being exchanged intraday are block offers or offers linked to blocks. 23% of the available balancing capacity also corresponds to block or linked offers. The majority of the volumes exchanged in intraday aims at reducing the gap between the solutions obtained from previous market clearings including, in particular, the day-ahead market one, towards the economic optimum. Bids, with a reasonable number of blocks and links, cannot perfectly reflect the complex constraints of a production unit portfolio. However, successive exchanges in intraday achieve a state of the system as close to the optimum as would a benevolent planner. Therefore, the modeled markets allow power companies to accurately translate their energy needs and their technical constraints into offers. There is no need to add more short-term market products in the simulation model, e.g. linear piecewise offers, minimum income offers of the day-ahead market in Spain, etc.

Balancing actions in the studied system are significantly impacted by the model and hypotheses of the management of hydro-electric reservoirs. In particular, the stock values of the reservoirs drive the imbalance prices. The strategy used in practice by power companies to define their water stock values is within industrial expertise and requires the simultaneous handling of environmental and technical constraints both in short term and long term. This model provides one method to model its economic use. Comparing the alternative hydro-electric reservoirs models would be worth investigating.

Before inferring a conclusion on market design by comparing simulation results, every simulation model should quantify the influence of the simulation bias on the results. A small variation in outputs could be the result of a change in market design or a difference inherent to the non-deterministic results of some algorithms. This bias still exists in practice with unit commitments not solved to optimality, human decisions that are not always rational, etc. It is particularly important to be able to draw conclusions on balancing since the concerned energy is marginal with respect to the total production. Performing the same simulation several times allows one to observe more consistent changes in the results. It is particularly important in an electrical system where a variation of the production cost by one percent represents millions of euros per year.

The next perspective for the model is therefore to perform statistical analyses and draw conclusions on the length of the neutralization delay, the imbalance settlement period, or the length of the system operator's operational window. The model could also be used to compare the market design on different country mixes or observe the influence of the harmonization of the balancing mechanism in Europe. The model can be extended to study the impact on the electrical system of power companies with different behaviors. One could even try to add an actor that would act randomly or negatively in order to perform a stress test on a market design. *SiSTEM* could also be used to benchmark different market offer strategies of power companies. The model could be extended to handle exchanges between different market zones, in particular the exchange of balancing services between various system operators.

7. APPENDIX A: UNIT MODELS

In the units-scheduling problem (3) of Section 3.2, each production unit i has its own set of technical constraints $\mathcal{X}_i$ and a cost function $C_i(\mathbf{p}_i)$. Technical constraints limit the output power $\mathbf{p}_i$ and the upward and downward balancing capacity, $\mathbf{b}_i^+$ and $\mathbf{b}_i^-$. In the model, three types of production unit are implemented: thermal units, hydro-electric reservoirs and curtailable production. They respectively are the topics of Sections 7.1, 7.2 and 7.3. Due to the discretization of the time horizon, the power is considered constant in each time step and every parameter must be scaled according to the length of a time step.

7.1. Thermal units model

The considered constraints of thermal units are: a minimum notice delay before changing the production plan, a minimum power defining the production phase, a minimum time in production phase, the start-up and shutdown ramping rates when the unit is below the minimum power, the upward and downward ramping rates in production phase, a minimum off-time after a shutdown and a minimum steady-state time in the production phase. Model (8) describes the constraints and objective function of a thermal unit without steady-state time constraints. Additional constraints needed to model the minimum steady-state time are given by model (10). Note that formulation (8) may differ slightly from the literature in order to obtain a valid schedule on sub-hourly resolutions.

Parameters

β_i	Variable cost
d_i^s	Shutdown ramping rate $\in \mathbb{R}^-$
$[d_i, u_i]$	Minimum and maximum ramping rate in production phase
$n^{\text{on}}, n^{\text{off}}$	Minimum up and down time steps
$\mathcal{M}_i$	Set of notice period
γ_i	Start-up cost
$[p_{i,t}^{\text{min}}, p_{i,t}^{\text{max}}]$	Production range in production phase
u^s	Start up ramping rate $\in \mathbb{R}^+$

Variables

$p_{i,t}$	Power output
$v_{i,t}$	Begin of a start-up phase
$w_{i,t}$	End of a shutdown phase
$x_{i,t}$	Start-up status
$y_{i,t}$	Production phase status
$z_{i,t}$	Shut-down status

To simplify notation, we use $\mathbf{p}_i = \{p_{i,t}, \forall t \in \mathcal{T}\}$.

Constraints

$$C_i(\mathbf{p}_i) = \sum_{t \in \mathcal{T}} (\beta_i p_{i,t} + \gamma_i v_{i,t}) \tag{8a}$$

with $\mathcal{X}_i = \Big\{$

$$x_{i,t} + y_{i,t} + z_{i,t} \leq 1 \qquad \forall t \in \mathcal{T} \tag{8b}$$

$$x_{i,t} \leq 1 - y_{i,t-1} - z_{i,t-1} \qquad \forall t \in \mathcal{T} \tag{8c}$$

$$y_{i,t} \leq x_{i,t-1} + y_{i,t-1} \qquad \forall t \in \mathcal{T} \tag{8d}$$

$$x_{i,t} + y_{i,t} \geq x_{i,t-1} \qquad \forall t \in \mathcal{T} \tag{8e}$$

$$z_{i,t} \leq y_{i,t-1} + z_{i,t-1} \qquad \forall t \in \mathcal{T} \tag{8f}$$

$$v_{i,t} - w_{i,t} = x_{i,t} + y_{i,t} + z_{i,t} - x_{i,t-1} - y_{i,t-1} - z_{i,t-1} \qquad \forall t \in \mathcal{T} \tag{8g}$$

$$v_{i,t} + w_{i,t} \leq 1 \qquad \forall t \in \mathcal{T} \tag{8h}$$

$$p_{i,t} \leq p^{\text{max}}_{i,t} y_{i,t} + p^{\text{min}}(x_{i,t} + z_{i,t}) \qquad \forall t \in \mathcal{T} \qquad (8i)$$
$$p^{\text{min}}_{i,t} y_{i,t} \leq p_{i,t} \qquad \forall t \in \mathcal{T} \qquad (8j)$$
$$p_{i,t} \geq d_i(z_{i,t} + z_{i,t+1} - 1) \qquad \forall t \in \mathcal{T} \qquad (8k)$$
$$p_{j,t} = p^0_{j,t} \qquad \forall t \in \mathcal{M}_i \qquad (8l)$$

$$p_{i,t} - p_{i,t-1} \leq u_i y_{i,t} + u^s_i x_{i,t} \qquad \forall t \in \mathcal{T} \qquad (8m)$$
$$p_{i,t} - p_{i,t-1} \geq d_i y_{i,t} + d^s_i z_{i,t} \qquad \forall t \in \mathcal{T} \qquad (8n)$$
$$p_{i,t} - p_{i,t-1} \geq d_i y_{i,t} + d^s_i z_{i,t} + u^s_i(x_{i,t} + x_{i,t-1} - 1) \qquad \forall t \in \mathcal{T} \qquad (8o)$$
$$p_{i,t} - p_{i,t-1} \leq u_i y_{i,t} + u^s_i x_{i,t} + d^s_i(z_{i,t} + z_{i,t-1} - 1) \qquad \forall t \in \mathcal{T} \qquad (8p)$$

$$n^{\text{on}}(y_{i,t} - y_{i,t-1}) \leq \sum_{\tau=t}^{t+n^{\text{on}}-1} y_{i,t} \qquad \forall t \in \mathcal{T} \qquad (8q)$$
$$1 - w_{i,t} \geq x_{i,\tau} + y_{i,\tau} \qquad \forall t \in \mathcal{T}, \tau \in \{t, t + n^{\text{off}} - 2\} \qquad (8r)$$

where $w_{i,t}, x_{i,t}, y_{i,t}, z_{i,t} \in \{0, 1\}, \forall t \in \mathcal{T} \}$. Constraints (8b)-(8h) link the start-up, production and shutdown phase binary variables. The unit may only be in one of the modes at most (8b). A unit cannot be started if it is in production or shutdown phase in the previous time step (8c). The production phase can only be reached from a start-up phase or a production phase (8d). From a start-up phase, the unit must go to another start-up phase or in-production phase (8e). A unit can be in shutdown phase if its status in the previous time step is either production or shutdown (8f). Equality (8g) defines the beginning of startup phases and the end of shutdown phases. This constraint tightens the formulation by expressing the state transition as a flow constrain [24]. The formulation is further tightened by inequality (8h) expressing that a unit cannot start and stop simultaneously [31].

Based on the three statuses of the unit: start-up, production or shutdown, the dynamic constraints of the unit are given by (8i)-(9f). The maximum production of the unit is constrained by (8i). If the unit is producing, its minimum power is defined by (8j). In the shutdown phase, the production can only be zero in the last shutdown time step (8k). The schedule of the unit is fixed on time steps no further than the notice delay (8l). Ramping constraints are handled by (8m)-(8n). The rampings in the start-up and shutdown phases are forced to equal the value given as a parameter by constraints (8o)-(8p). Note that these constraints are only active if the starting or shutdown phase lasts more than one time step to handle the starting of a unit in the middle of a time step. A started unit must be on for a minimum amount of time steps as enforced by (8q). A unit which is off must stay off for at least a minimum amount of time steps (8r).

If the thermal unit is eligible to provide reserves, the following additional constraints are added to the model of the unit, or else the reserve capacity of the unit is set to zero. A thermal unit is eligible if its steady-state period and its notice delay are less than or equal to a balancing period. Note that even if the unit is not set as eligible, balancing capacity can still be obtained by computing the available flexibility of the unit, as explained in Section 3.4.

Additional parameter

$r^+_{i,t}, r^-_{i,t}$	Upward and downward reserve of the unit

Additional variable

$b^+_{i,t}, b^-_{i,t}$	Upward and downward balancing capacity of a unit

Additional constraints

$$b^+_{i,t} + r^+_{i,t} \leq p^{\text{max}}_{i,t} - p_{i,t} \qquad \forall t \in \mathcal{T} \tag{9a}$$
$$b^-_{i,t} + r^-_{i,t} \geq y_t p^{\text{min}}_{i,t} - p_{i,t} \qquad \forall t \in \mathcal{T} \tag{9b}$$
$$b^+_{i,t} + r^+_{i,t} \leq y_{i,t}(p^{\text{max}}_{i,t} - p^{\text{min}}_{i,t}) \qquad \forall t \in \mathcal{T} \tag{9c}$$
$$b^-_{i,t} + r^-_{i,t} \geq y_t(p^{\text{min}}_{i,t} - p^{\text{max}}_{i,t}) \qquad \forall t \in \mathcal{T} \tag{9d}$$
$$b^+_{i,t} + r^+_{i,t} + p_{i,t} - p_{i,t-1} \leq u_i \qquad \forall t \in \mathcal{T} \tag{9e}$$
$$b^-_{i,t} + r^-_{i,t} + p_{i,t} - p_{i,t-1} \geq d_i \qquad \forall t \in \mathcal{T} \tag{9f}$$

The reserve that must be provided by the unit is enforced by (9a)-(9f). These constraints also compute the available amount of balancing capacity from the unit. Equations (9a)-(9b) ensure that the necessary power margin is kept. Balancing and reserve cannot be provided if the unit is not on, following constraints (9c)-(9d). Inequalities (9e) - (9f) imposes the ramping constraint on the balancing capacity.

Some thermal production units need to include a minimum amount of time in their model during which the power is constant, to stabilize its operation. This is not usually included in traditional unit commitment formulations since they are usually done on an hourly time step. If production units switch from ramping up to ramping down without this period of steady operation, it increases the risk of equipment damage [44]. It is mandatory for higher resolution unit commitment to model a steady-state period. Although nuclear power plants control systems enable a fast plant response, there are several constraints that prevent the plant from regularly operating that way such as fuel integrity problems and xenon oscillations [23]. Cycling affects the lifespan of heat recovery steam generators, which are part of combined cycle plants [33]. Disregarding fatigue of combined-cycle gas turbine power plants leads to average operating costs that are higher than those resulting from taking fatigue into account [43]. In this model, minimum steady-state periods are imposed by extending the optimization model (8) with the constraints given in (10).

Additional parameters

n^b	Minimum number of steady-state time steps

Additional variables

$y^a_{i,t}$	Upward ramping production phase status
$y^b_{i,t}$	Steady-state production phase status
$y^c_{i,t}$	Downward ramping production phase status

Additional constraints

$$y^a_{i,t} + y^b_{i,t} + y^c_{i,t} = y_{i,t} \qquad \forall t \in \mathcal{T} \tag{10a}$$
$$y^a_{i,t} + y^b_{i,t} \geq y^a_{i,t-1} \qquad \forall t \in \mathcal{T} \tag{10b}$$

$$y^b_{i,t} + y^c_{i,t} + z_{i,t} \geq y^c_{i,t-1} \qquad \forall t \in \mathcal{T} \qquad (10c)$$
$$y^a_{i,t} \leq 1 - (y^c_{i,t-1} + z_{i,t-1}) \qquad \forall t \in \mathcal{T} \qquad (10d)$$
$$y^c_{i,t} \leq 1 - (y^a_{i,t-1} + x_{i,t-1}) \qquad \forall t \in \mathcal{T} \qquad (10e)$$

$$x_{t-1} \leq x_{i,t} + y^a_{i,t} + y^b_{i,t} \qquad \forall t \in \mathcal{T} \qquad (10f)$$
$$y^a_t \leq x_{t-1} + y^a_{t-1} + y^b_{t-1} \qquad \forall t \in \mathcal{T} \qquad (10g)$$
$$y^c_t \leq y^b_{t-1} + y^c_{t-1} \qquad \forall t \in \mathcal{T} \qquad (10h)$$

$$d_i(1 - y^b_{i,t}) \leq p_{i,t} - p_{i,t-1} \leq u_i(1 - y^b_{i,t}) \qquad \forall t \in \mathcal{T} \qquad (10i)$$
$$d_i(1 - y^a_{i,t}) \leq p_{i,t} - p_{i,t-1} \leq u_i(1 - y^c_{i,t}) \qquad \forall t \in \mathcal{T} \qquad (10j)$$
$$p_{i,t} - p_{i,t-1} \geq u^a_i(y^a_{i,t} + y^a_{i,t-1} + x_{i,t-1} - 1) + d_i(y^c_{i,t} + z_{i,t}) \qquad \forall t \in \mathcal{T} \qquad (10k)$$
$$p_{i,t} - p_{i,t-1} \leq u_i(x_{i,t} + y^a_{i,t}) + d^c_i(y^c_{i,t} + y^c_{i,t-1} - 1) \qquad \forall t \in \mathcal{T} \qquad (10l)$$
$$p_{i,t} - p_{i,t-1} \leq u_i(x_{i,t} + y^a_{i,t}) + d^c_i(z_{i,t} + y^c_{i,t-1} - 1) \qquad \forall t \in \mathcal{T} \qquad (10m)$$
$$p_{i,t} - p_{i,t-1} \leq u_i(x_{i,t} + y^a_{i,t}) + d^c_i(y^c_{i,t} + y^c_{i,t+1} + z_{i,t+1} - 1) \qquad \forall t \in \mathcal{T} \qquad (10n)$$
$$n^b(y^b_{i,t} - y^b_{i,t-1}) \leq \sum_{\tau=t}^{t+n^b-1} y^b_{i,t} \qquad \forall t \in \mathcal{T} \qquad (10o)$$

with $y^a_{i,t}, y^b_{i,t}, y^c_{i,t} \in \{0,1\}, \forall t \in \mathcal{T}$. Constraints (10a)-(10e) defines the variables of the production phase status. They are tightened by inequalities (10f)-(10h). Ramping constraints in the production phase are enforced by (10i)-(10j). Additional ramping constraints (10k)-(10n) ensures the continuity of the ramping, i.e. ramping at the maximum ramping rate if the unit is ramping in two consecutive time steps. Finally, the minimum steady-state time is enforced by (10o).

To simplify the description, models (8)-(10) ignore cases where constraints refer to time steps outside of the optimization horizon $\mathcal{T}$. If a schedule is already defined, constraints for the time steps immediately before and after the optimization horizon are satisfied by increasing the horizon by two time steps and fixing the corresponding powers to the given realizations. Cases regarding more than two time steps in the future are handled by adding constraints and fixings ensuring the consistency of the solution outside of the optimization horizon. For instance, consider a unit which has been switched off at 3:00, a minimum off time of two hours, and an hourly optimization horizon from 4:00 to 6:00. A pre-processing must prevent the unit from being be switched on until 5:00. Another example is a unit that is switched off until 14:00, a minimum off time of two hours and an optimization horizon from 11:00 to 13:00. Due to the scheduled start, the unit cannot be switched on in this optimization horizon and satisfy the minimum off time afterwards. Similar considerations need to be taken into account for the minimum on and the steady-state times.

Upward unit-based flexibility is obtained by solving the optimization problem (5) and proposing, as offers, the difference between the current schedule and a maximum production schedule. This flexibility needs to be converted into standard bids as shown in Figure 12a. Upward offers are separated into two parts: base block bids and operation bids. Figure 12a illustrates the process of building upward flexibility offers for units without steady-state constraint. The flexibility on market periods $1-12$ is split into block bids $1-3$ and operation bids $4-11$. Base block bids offer the flexibility of the unit below its minimal power. The cost of these bids includes the unit variable costs and the start-up costs. Start-up costs are considered depending on the schedule. A basic example is the case where the unit is started only to provide flexibility. However, it is not always as straightforward to include the start-up cost. For instance, bid 1 does not include any start-up cost since the unit would be already started anyway in market period 3. Another example is given by bid 2, in which the start-up cost needs to be subtracted since one start-up is avoided if the bid is accepted. Operation bids cover the flexibility above the minimal power and are offered at the unit variable cost. They are dependent on the base bids. Bid 4 can only be accepted if bid 1 is accepted. Bids 6 to 9 can only be accepted if bid 2 is accepted. Bid 5 and 10 are independent. If the thermal unit has a minimum steady-state time greater than a market period, bids $4-12$ are merged into a single offer. In the latter case, this single operation can be partially accepted only if bids $1-3$ are accepted. The principle for building downward flexibility is similar and illustrated in Figure 12b. The downward flexibility is separated into two parts: the operation bids above minimum power, and the base block bids. Base bids may only be accepted totally and include the start-up costs if they are relevant. For the downward flexibility, no links are integrated between base bids and operation bids. In the example of Figure 12b, bid 1 may in theory be accepted and bid 6 rejected. This situation is unlikely to happen in practice since bid 1 is more expensive due to the start-up cost and more difficult to use since it is a block covering multiple periods. Future work could add an exclusive relationship between the base bids and a new block bid, including the base bids and the operation bids. For units with steady-state constraints, operation bids are offered as a single offer. If its length is greater than the steady-state time, the resulting multi-period offer may-be partially accepted, otherwise a binary bid is offered. In the example of Figure 12a, areas 4 to 11 are merged in a single bid with partial acceptance. Operation blocks of duration inferior to the steady-state period are also merged with base blocks if there is any block covering one of the time steps of the operation block.

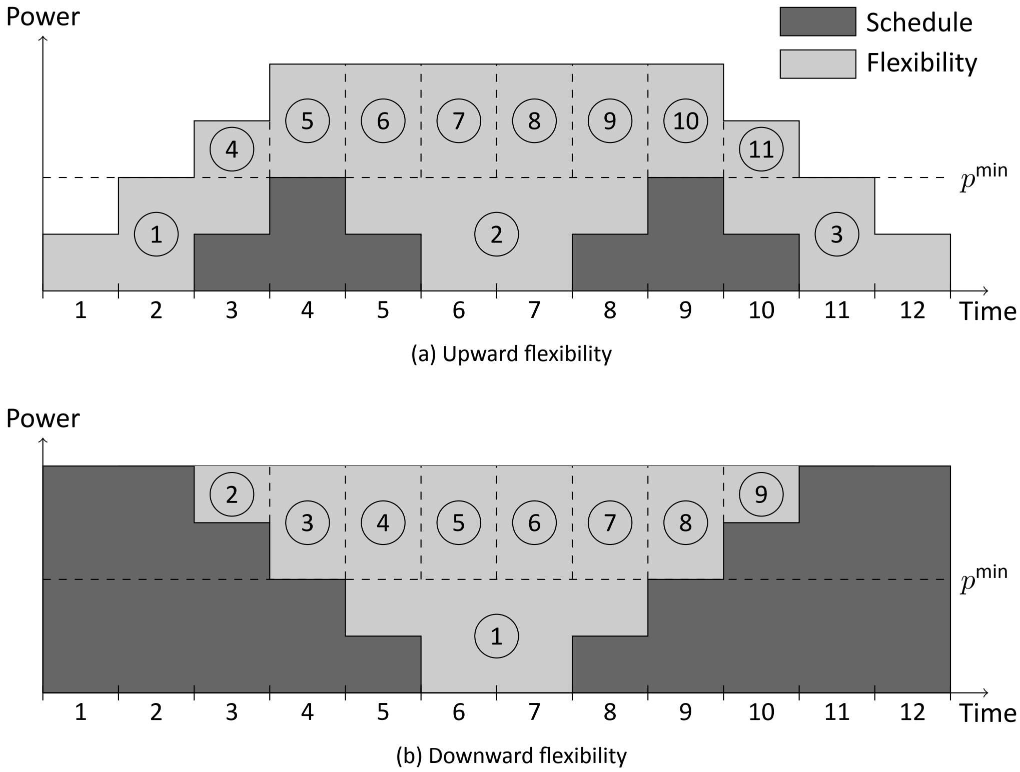


Figure 12: Building of flexibility offers of a thermal unit.

7.2. Hydro-electric reservoirs model

In practice, the management of hydro-electric reservoirs is very complex and differs from one reservoir to another. Exploitation of the water in one place must conform to a dedicated contract, including many constraints difficult to formulate: dynamic production constraints, fishing constraints, seasonality constraints, etc. On the time scale of the study, the complexity behind these dynamics may be summarized by simple dynamic bounds on the storage level and the power output of the reservoir. A portfolio of hydro-electric reservoirs $\mathcal{U}^h$ is scheduled at once using model (11) incorporating a coupling constraint between the different reservoirs in the global portfolio model $\mathcal{X}^h$.

Sets

$\mathcal{U}_i^h$	Hydro-electric reservoirs of the portfolio
$\mathcal{M}_j$	Notice period

Parameters

$a_{j,t}$	Stock supply
Δt	Simulation step length
n_j	Stock release efficiency
$p^0_{j,t}$	Initial schedule
$[p^{\text{min}}_{i,t}, p^{\text{max}}_{i,t}]$	Power output bounds
$r^+_{j,t}, r^-_{j,t}$	Upward and downward reserve of the unit
$[s^{\text{min}}_{j,t}, s^{\text{max}}_{j,t}]$	Individual stock bounds
$[S^{\text{min}}_{i,t}, S^{\text{max}}_{i,t}]$	Global stock bounds
$s_{i,0}$	Initial stock
T	Last simulation time step in $\mathcal{T}$
β_j	Stock value
$[\beta^{\text{min}}_i, \beta^{\text{max}}_i]$	Cost of violating the minimum and maximum collection stock bound
$[\beta^{\text{min}}_j, \beta^{\text{max}}_j]$	Cost of violating the minimum and maximum stock bound

Variables

$p_{j,t}$	Power output
$b^+_{j,t}, b^-_{j,t}$	Upward and downward balancing capacity of a unit
$s_{j,t}$	Stock level
$[D^{\text{min}}_{i,t}, D^{\text{max}}_{i,t}]$	Global stock bounds slacks
$[d^{\text{min}}_{j,t}, d^{\text{max}}_{j,t}]$	Stock bounds slacks

Constraints

$$C_i(\mathbf{p}_i) = \sum_{j\in\mathcal{U}_i^h}\left(-\beta_j(s_{j,T}-s_{j,0}) + \sum_{t\in\mathcal{T}}\left(\beta^{\text{min}}_j m^{\text{min}}_{j,t} - \beta^{\text{max}}_j m^{\text{max}}_{j,t}\right)\right) + \sum_{t\in\mathcal{T}}\left(\beta^{\text{min}}_i M^{\text{min}}_{i,t} - \beta^{\text{max}}_i M^{\text{max}}_{i,t}\right)$$

with $\mathcal{X}^h = \{$

$$s_{j,t} = s_{j,t-1} + a_{j,t}\Delta t - n_j p_{j,t}\Delta t \qquad \forall (j,t)\in\mathcal{U}^h\times\mathcal{T} \tag{11a}$$

$$p_{j,t} + b^+_{j,t} + r^+_{j,t} \leq p^{\text{max}}_{j,t} \qquad \forall (j,t)\in\mathcal{U}^h\times\mathcal{T} \tag{11b}$$

$$p_{j,t} + b^-_{j,t} + r^-_{j,t} \geq p^{\text{min}}_{j,t} \qquad \forall (j,t)\in\mathcal{U}^h\times\mathcal{T} \tag{11c}$$

$$s_{j,t} - n_j\Delta t\sum_{\tau=0}^{t}\left(b^+_{j,\tau} + r^+_{j,\tau}\right) \geq s^{\text{min}}_{j,t} + d^{\text{min}}_{j,t} \qquad \forall (j,t)\in\mathcal{U}^h\times\mathcal{T} \tag{11d}$$

$$s_{j,t} - n_j\Delta t\sum_{\tau=0}^{t}\left(b^-_{j,\tau} + r^-_{j,\tau}\right) \leq s^{\text{max}}_{j,t} + d^{\text{max}}_{j,t} \qquad \forall (j,t)\in\mathcal{U}^h\times\mathcal{T} \tag{11e}$$

$$\sum_{j\in\mathcal{U}^h}\left(s_{j,t} - n_j\Delta t\sum_{\tau=0}^{t}\left(b^+_{j,\tau} + r^+_{j,\tau}\right)\right) \geq S^{\text{min}}_t + D^{\text{min}}_{j,t} \qquad \forall t\in\mathcal{T} \tag{11f}$$

$$\sum_{j\in\mathcal{U}^h}\left(s_{j,t} - n_j\Delta t\sum_{\tau=0}^{t}\left(b^-_{j,\tau} + r^-_{j,\tau}\right)\right)\Delta t \leq S^{\text{max}}_t + D^{\text{max}}_{j,t} \qquad \forall t\in\mathcal{T} \tag{11g}$$

$$p_{j,t} = p^0_{j,t} \qquad \forall (j,t) \in \mathcal{U}^h \times \mathcal{M}_j \tag{11h}$$

where $s_{j,t} \in [s^{\text{min}}_{j,t}, s^{\text{max}}_{j,t}], p_{j,t} \in [p^{\text{min}}_{j,t}, p^{\text{max}}_{j,t}]\ \forall (j,t) \in \mathcal{U}^h \times \mathcal{T}, (d^{\text{min}}_{j,t}, d^{\text{max}}_{j,t}) \in \mathbb{R}^- \times \mathbb{R}^+\ \forall (j,t) \in \mathcal{U}^h \times \mathcal{T}, (D^{\text{min}}_{i,t}, D^{\text{max}}_{i,t}) \in \mathbb{R}^- \times \mathbb{R}^+\ \forall t \in \mathcal{T}\}$. The cost of spilling water expressed in (11a) is given by the difference of stock level multiplied by the stock value. Evolution of the stock from one time step to another is given by equality (11a). Power bounds, integrating the flexibility, are given by inequalities (11b)-(11c). The effect of the worst-case use of flexibility on the stock is defined by (11d)-(11e). Stock bounds are implemented as soft constraints. The cost function (11a) penalizes the violation of stock bounds. In practice, these stock bounds are given to satisfy long-term constraints of the stock and can therefore allow slight violations. The bounds on the total stock constraint are enforced by (11f)-(11g), including the available flexibility. Finally, constraint (11h) fixes the schedule of a reservoir in time steps in which it cannot be modified.

Note that in model (11), the stock value is assumed to be constant. The model could be refined by considering the dependence of the stock value to the stock level. However, this would lead to a nonlinear, yet convex optimization problem which would therefore be less tractable. Since our optimization horizon is at most a few days, the approximation is reasonable and does not justify the major overhead in computation time. The stock values are updated in each simulation time step as a function of the stock level at the last neutralized simulation time step. The stock value for one time step is given by an affine function between two given stock values associated with the individual stock bounds. The default parameters are arbitrarily set to 20 and 120 €/MWh, leading to a stock value of 70 €/MWh at the middle of the stock range. For the assessment of overall generation costs, the final stock is valued at a fixed stock value of 50 €/MWh.

7.3. Curtailable production model

This model corresponds to the uncertain energy generation producing by default but that may be curtailed at a given cost, i.e. solar or wind production units. By default, this cost is null. One could take negative costs to take into account subsidies depending on the specificities of the related support scheme. The model of a curtailable unit i is given by (12) and relies on a forecast of the available production of the unit. The details of the forecast mechanism are given in Section 3.1.

Parameters

β_i	Variable cost
$p^{\text{max}}_{i,t}$	Forecast of available production
$r^+_{i,t}, r^-_{i,t}$	Upward and downward reserve of the unit

Variables

$b^+_{i,t}, b^-_{i,t}$	Upward and downward balancing capacity of the unit
$p_{i,t}$	Power output

Constraints

$$C_i(\mathbf{p}_i) = \sum_{t \in \mathcal{T}} \beta_i p_{i,t} \tag{12a}$$

with $\mathcal{X}^h = \{$

$$-b^-_{i,t} \leq p_{i,t} \leq p^{\text{max}}_{i,t} - b^+_{i,t} \qquad \forall t \in \mathcal{T} \tag{12b}$$

where $p_{i,t} \in [0, p_{i,t}^{\max}]\ \forall t \in \mathcal{T}\ \}$. In this model, curtailable production is not allowed to provide reserves but may be used as a means of balancing. Flexibility of the production unit is offered as described in Section 3.3 except for balancing offers. The capacity of balancing offers is slightly reduced to account for uncertainty. The default reduction is to propose, at most, 90% of the predicted production and to keep at least 1 MW of capacity.

8. APPENDIX B: ADDITIONAL RESULTS

This appendix presents the results of six additional simulation cases. See Table 3 for the description of each case. The results of Sections 8.1 and 8.2 show that using a benevolent monopolistic representation of the system or an hourly resolution requires significantly less computation time but still leads to relatively accurate energy mixes and average production costs. Section 8.3 assumes perfect forecasts and show that forecast errors explains significant volumes of intraday exchanges and balancing activations. Section 8.4 shows how removing the intraday market impacts the use of the different technologies. Section 8.5 highlights that it is difficult for a power company to forecast how the system imbalance will evolve within the next few hours. Section 8.6 illustrates how a proactive system operator can help the system by activating less flexible units, depending on its ability to anticipate system imbalances.

8.1. Hourly resolution of the simulation

The maximum resolution of the simulation is set to one hour instead of 15 minutes in the base case. Therefore, the resolution of the energy markets, the balancing activation, imbalance prices and imbalance settlements are all set to one hour. Compared to the base case with a resolution of a quarter of hour, many thermal constraints can be dropped. In particular, ramping constraints are never binding. The decrease of the time resolution leads to optimization problems with four times fewer variables. The computation time for the whole month drops to two hours.

The total average production cost decreases by 2.2% to 13.73 €/MWh. The day-ahead energy market is not affected by the change of resolution. The intraday market keeps similar prices but exchanged volumes decrease by 50% to 1.8% of the average production. The forecast errors generated by the mechanism described in 3.1 are doubled when used at an hourly resolution. This error doubles the amplitude of the imbalance signal but still leads to 40% lower imbalance prices. These prices are the results of lower hydro-electric reservoir stock values by the same amounts. Since technical constraints of thermal production are less binding; flexibility from the hydro-electric production is less requested. The stock values decrease up to the point where they match the variable cost of CCGTs to have the opportunity to sell the energy brought by the exogenous stock supplies into the energy markets. CCGTs provide 50% of the balancing at an hourly resolution which further decreases the use of the flexibility from the reservoirs. Even the regular nuclear production is able to provide 5% of the upward balancing capacity and 2% of the downward one. Results confirm that ramping constraints are useless with one-hour time resolution but that the outcome of balancing actions is influenced at higher resolutions.

8.2. Benevolent monopoly

In this scenario all assets of the system, including the consumption, are gathered into the portfolio of a single actor. Since the actor strategy is to balance itself at any cost, this scenario is similar to a benevolent monopoly. Because markets are not relevant in monopoly situations, no day-ahead nor intraday markets are simulated and therefore the corresponding prices do not exist. Balancing is still performed by the system operator via the explicit communication of the capacity. The forecast mechanism is identical to the base case. Since it is applied to the total consumption and non-dispatchable production, the forecast of the residual demand of the monopoly is different from the sum of the forecasts of the four actors.

The average production cost obtained after simulation is 14.23 €/MWh, i.e. similar to the base case taking into account the simulation bias. This shows that the markets are functioning well in this simulation case given the behavior of the market participants. Since there is only one actor managing the total hydro-electric reservoirs, there is a single stock value. This results in only 3.5% of counter-activations which comes from switches between blocks of OCGTs with reservoirs' production.

The energy mix in both cases is similar given the simulation bias. Setting a 5% optimality gap on the total of the system may lead to a less optimal solution than four actors optimizing their portfolio until they reach their individual 5% gap guarantee. This simulation also took significantly less computation time, 2 hours and 45 minutes, partly explained by the lack of need to build flexibility offers to the energy markets. This result encourages the use of global unit-commitment models to perform studies on energy mixes and global production costs. However, multi-actor models provide outcomes of market clearings, exchanges between actors and different actors strategies to manage their own portfolio.

8.3. Perfect forecasts

In this case, the four actors make perfect forecasts and no outage occurs. Even if the actors have incentives to balance themselves, imbalances still occur since the final production is the results of exchanges between the power companies.

Simulation results show that volumes exchanged in day-ahead are similar in the base case and the perfect forecast case and the median price are identical. Intraday volumes exchanged decrease by 20%. The median intraday price and the standard deviation are lower, respectively at 27.88 €/MWh and 16.34 €/MWh. The standard deviation of imbalances drops from 58.64 MW to 2.28 MW. The latter is mainly supported by actor 3 with a standard deviation of 1.88 MW. Since actor 3 owns no production asset, it can only rely on the markets to buy or sell its energy. This is nontrivial to achieve with block offers, binary acceptances, block links and the energy markets resolution; 1 MWh in this model. The latter is clearly the main cause of the remaining imbalances. Other actors can rely on their production to balance themselves. Actor 4 obtains no upward imbalance since it can always curtail its renewable production. The imbalance price drops by 10 €/MWh to a median of 32.2 €/MWh. The total production costs decrease by 4% to 13.47 €/MWh. The reduction of 0.56 €/MWh comes from the idleness of OCGTs and a 1.25% increase of nuclear production.

The results obtained with forecast errors and with a perfect forecast highlight that significant volumes of intraday exchanges are used by actors to balance their forecast errors. Thus, forecast errors should be taken into account to properly analyze short-term electricity markets, especially intraday and balancing markets.

8.4. Absence of intraday market

Removing the intraday prevents the refinement of the production schedules built after the clearing of the day-ahead market. In particular, actors 1 and 2 have to handle variations at the 15 minutes resolution alone with respect to their hourly net position and the gap between the cleared solution and their technical constraints.

The simulation results show an increase of the average production cost by 6.77% to 14.98 €/MWh. This cost increase results from a 1.5% decrease of the nuclear energy mainly compensated by a 0.86% increase of hydro-electric reservoirs and 0.27% of OCGTs. The median day-ahead energy market price is nearly identical but the standard deviation doubles. The cause is the increased stock values where the median increases by 44% to 77 €/MWh. This particularly affects day-ahead market prices at the end of the simulated month when consumption reaches the capacity of the production and reservoirs production is in the money. This results in an increase of median imbalance prices by 61% to 67 €/MWh for upward and downward directions. The imbalance itself increases with a standard deviation of 72.83 MW instead of 58.64 in the base case, which only corresponds to a 22% increase. Note that the system operator is reactive in this simulation. Increasing the operational window of the system operator could reduce the average production cost.

Removing intraday markets while considering technical constraints in actors' offers significantly influences the use of the various technologies: flexible technologies are used more, to the detriment of less flexible technologies.

8.5. Price-based actor balancing

In this scenario, actor 1 uses the current imbalance prices as forecasts of the prices for the next one hour and half if the imbalance of the system is important following the strategy described in Section 3.2. Note that in practice this opportunity could be exploited by all actors, potentially with more aggressive strategies, and lead to different results.

The energy markets are left unchanged between this proactive actor balancing case and the base one. There is no prominent difference in imbalance signals. However, the imbalance prices decrease by 22% to reach a median of 32.6 €/MWh. This decrease is caused by a 16.8% decrease of hydro-electric reservoirs stock values to a median of 35.95 €/MWh while there is only a 5.5% decrease of the hydro-electric reservoirs production. The global balance of the system operator is stable since the costs from balancing activations are covered by the imbalance settlement. Figure 13 provides an overview of the balancing decisions taken by actor 1 in two days where the consumption is close to the maximum production capacity. In particular, actor 1 helps the system if its scheduled deviation is in the opposite direction than the system imbalance. For instance, it happens the second day at 11:00. However, the first day at 8:00 or 18:00, actor 1 schedules a deviation in the same direction as the imbalance signal. In both cases the system is short at the time of the scheduled deviation and one hour and a half before when the actor makes its forecast. Therefore, this deviation was intended to spare production costs assuming that the imbalance price will stay constant. The imbalance price increased in both cases which qualifies it as a bad anticipation. The total revenues of actor 1 are not significantly impacted by these actions. Observed changes in balancing and imbalance revenues are of the order of magnitude of the simulation bias.

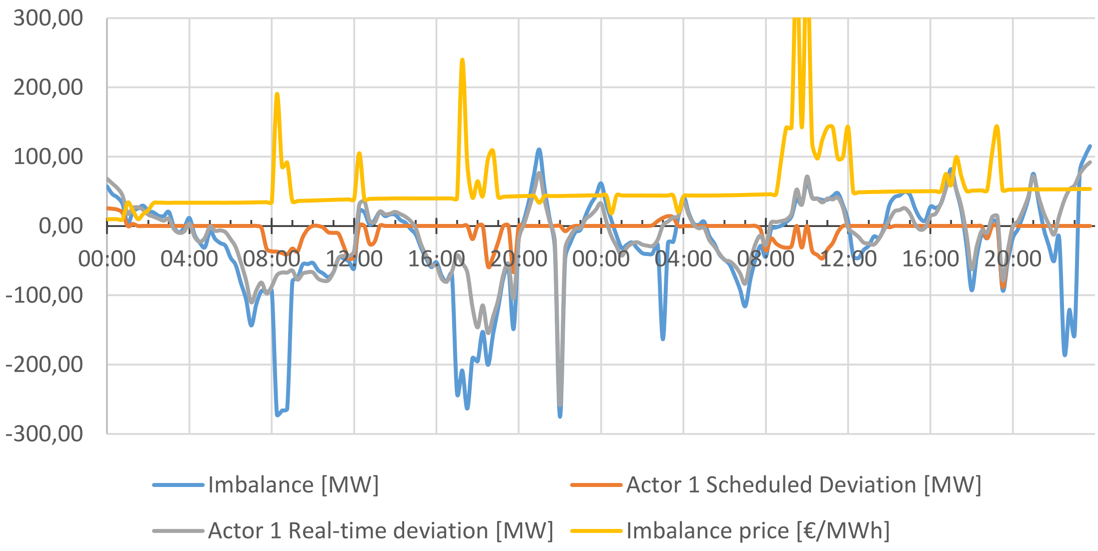


Figure 13: Effect of the balancing strategy of actor 1 on the imbalance signal and the imbalance price in two days where the consumption is close to the maximum production capacity.

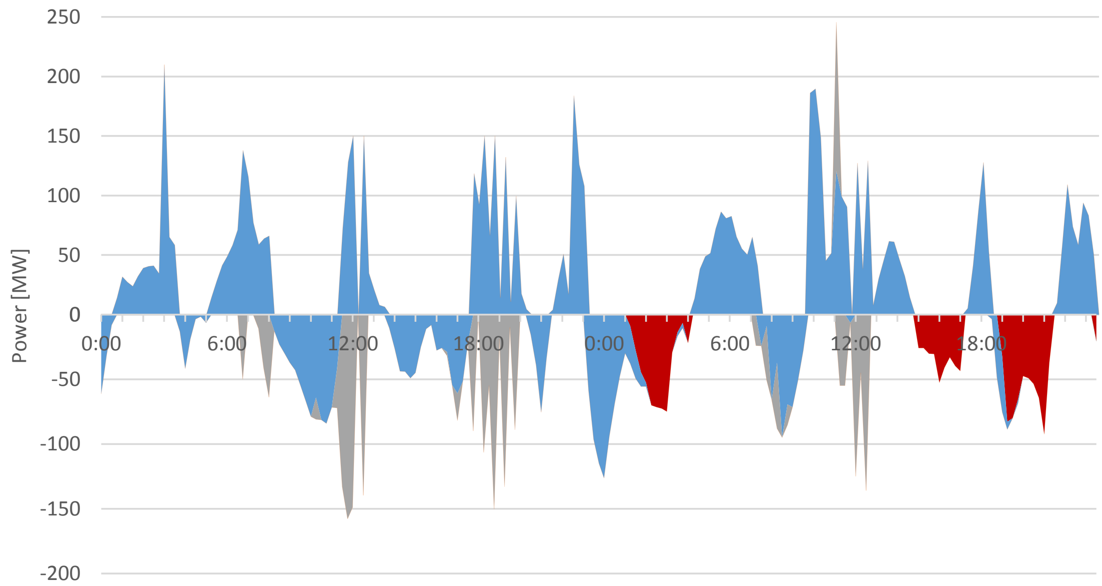
In practice, it is difficult to forecast how the system imbalance will evolve within the next few hours. The results with a risk-taking balancing strategy confirms this intuition.

8.6. Proactive system operator

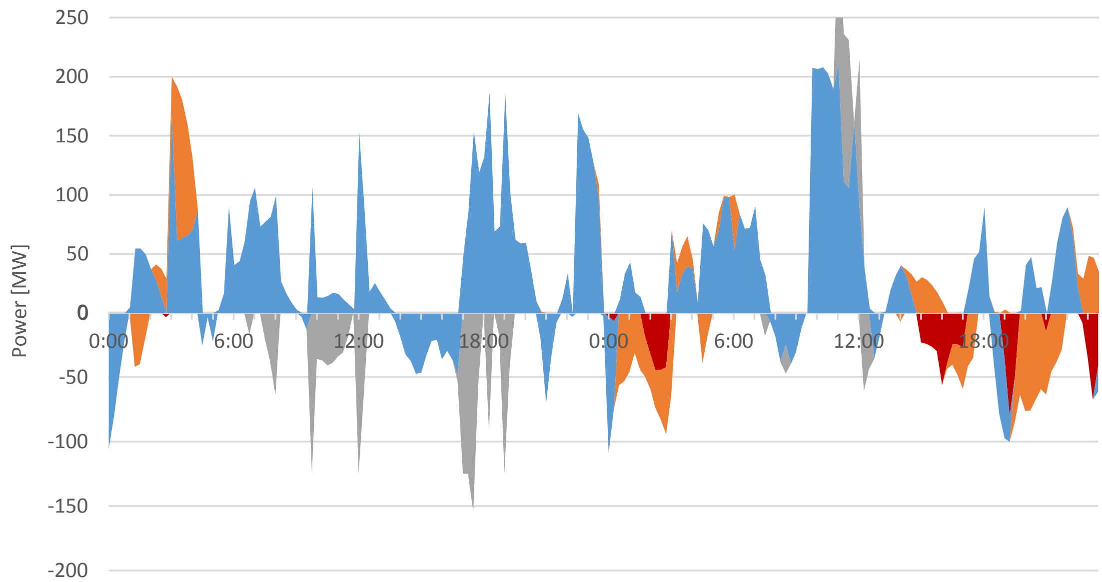
This scenario sets the neutralization delay to one hour, preventing power companies balancing themselves after this delay, whereas the system operator is allowed to act proactively up to one hour ahead. In comparison, the base case corresponds to a reactive system operator. The results of this section are particularly meant to show the capabilities of the model and not to draw conclusions on the cost difference between a proactive and reactive system operator. Such results could not be obtained by comparing single-run simulation due to the simulation bias.

Figure 14 shows the balancing activations per technology in two days where the consumption is close to the maximum production capacity. The simulation of the reactive base case is presented in Figure 14a. The only available technologies are the remote-control reservoirs, the flexible nuclear unit and the OCGTs. Economic counter activations occur around 12:00 and at 18:00 the first day. Power companies prepare their schedule based on their forecast of the residual demand. If this residual demand is high, OCGTs may be scheduled to produce. If the realization is lower than the forecast, the system operator can replace the production from OCGTs by a lower amount of hydro-electric reservoir productions.

The balancing activation resulting from the simulation of a system with a proactive system operator is given in Figure 14b. Note that the activated volumes are not identical since the neutralization delay is different and the simulation bias changes the imbalance of the system. Compared to the reactive case, CCGTs can now be used for balancing if the system operator is able to anticipate imbalances. Correct anticipation occurs in the beginning of the first day and around 6:00 the second day. There are some cases of proactive activation leading to counter-activations due to the bad previsions. These cases arise the second day at 16:00 and 23:00 where most of the balancing energy from proactive activation is compensated by flexible nuclear production. The performance of a proactive system operator is therefore highly dependent on its ability to forecast system imbalances.



(a) Reactive system operator case.



(b) Proactive system operator case.

Figure 14: Balancing activations per technology in a simulation of the reactive base case and one with a proactive system operator over two days.

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