Analysis of imbalance settlement designs in electricity systems

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Sammanfattning

I denna rapport analyseras effektiviteten och effekterna av olika prissättningssystem för obalanser på elmarknaden. Arbetet har utförts kopplat till ett pågående forskningsprojekt på EDF (Electricité de France) om elbalansering och bygger på en simuleringssmodell SiSTEM som utvecklats av EDF och universitetet i Liege. Analysen fokuserar på konsekvenserna av prissättningen för obalanser på marknadsaktörer och nätoperatören. Intäkterna för marknadsaktörerna och nätoperatören analyseras samt hur prissättningen påverkar marknadsaktörernas beteende. När marknadsaktörerna tillåts vara i obalans istället för att balansera sig intern utökar volymen av obalanser och interaktionerna mellan kraftföretag och nätoperatören. Detta leder till en ökning av den sammanlagda systemnyttan. När prissättningen förändras genom att ta bort straff-faktorn som beskrivs i delen om prissättningen för obalanser ökar aktörernas kostnader för obalanser. Även förändrad prissättning från genomsnittskostnad till marginalkostnad för avropad reglerkraft ökar aktörernas kostnad för obalanser. Eftersom aktörerna anpassar sitt beteende till att ta hänsyn till obalanser, dvs. de har medvetet obalanser på grund av sina förväntningar om systemets obalanser, ökar deras kostnader för obalanser, då de optimiserar sin egen portfölj utan att ta hänsyn till andra aktörer.
Abstract

This report analyses the efficiency and re-distributive effects of diverse Imbalance settlement designs in the electricity market. This work relies on an on-going EDF (Electricité de France) research project on electricity balancing and is based on a simulator tool, SiSTEM, developed by EDF and the University of Liege. The analysis focuses on the consequences of imbalance settlement on market participants and on the Transmission System Operator. The revenues of market participants and the Transmission System Operator are analyzed as well as the impact of imbalance settlement design on market participants’ behaviour.

Based on our case study simulations’ results, the following conclusions could be drawn. When all the market participants are adjusting their behavior regarding the imbalance settlement, imbalance volumes are significant and increase the interactions between power companies and the Transmission System Operator. However, the system social welfare is improved. Removing the penalty factor present in the definition of imbalance prices or moving from average to marginal pricing increases the imbalance cost. For Balancing Responsible Parties, if they adjust their behavior regarding the imbalance settlement, i.e. they deliberately have imbalances due to their expectation of the system imbalances, they will increase their imbalance costs as they try to optimize their own portfolio (comparing their own internal cost if they are in balance, with the imbalance cost) without looking at the other Balancing Responsible Parties.
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Glossary

**BRP** Balancing Responsible Party.

**BSP** Balancing Service Provider.

**CRE** Commission de régulation de l’énergie.

**EDF** Electricité de France.

**RTE** Réseau de transport d’électricité.

**TSO** Transmission System Operator.
Chapter 1

Introduction

1.1 Background

Electric power systems evolve towards situations with a major share of generation from intermittent resources where uncertainties on system equilibrium have to be managed thanks to widespread controllable units with a variety of capabilities. In this context, the cost efficiency of the power system will depend highly on operational decision making with respect to short-term flexibilities. The way market participants interact with each other and the Transmission System Operator (TSO) balances the system are generally determined by the market design and the regulatory framework in the administrative area.

1.1.1 Short-term electricity markets

Electricity, being a particular good, is traded (purchased and sell) on different markets. Indeed, there are four constraints with electricity that other goods don’t have. First of all, electricity is not storable (not cost-effectively in big quantity nowadays) so production and consumption have to be balanced in real time. Electricity can be bought and sold from two years until one week (or so) in advance. This is the work of the forwards market. Second of all, electricity generators have dynamic constraints. A coal unit, for example, needs more than 10 hours to get started. Day ahead market helps market participants and generators to integrate dynamic constraints. Third of all, unforeseen changes in production or consumption may occur. The weather can change quickly or a unit can face an outage. An intraday (or adjustment) market exist to face hazards. Finally, throughout the delivery of electricity, the production should be always equal to the consumption. In order to face this constraint, there are two mechanisms: the balancing (regulating) market and then (after the delivery) the financial imbalance settlement. These mechanisms are present in every country but each has different rules to make them work. Short-term electricity markets are summarized on figure 1.1
Short-term electricity markets involve day ahead, intraday and the balancing market. Imbalance settlement is linked with the balancing market. It is the financial result of the Balancing market even if market participants which bid on the balancing market: the Balancing Service Provider (BSP)s are not the same market participants which pay for their imbalances: the Balancing Responsible Party (BRP)s. This report will focus on balancing market and more specifically imbalance settlement designs.

### 1.1.2 The company: EDF

Electricité de France (EDF) group is the main company producing and supplying electricity mainly in France and in Europe. It is the second largest electricity producer in the world. Since 2004, EDF has been privatized after having been under the state control and on a monopoly of production and retail. The company operates on all the electricity markets. In France, its electricity production is dominated by nuclear energy.

The work presented in this report has been done in the Research and Development department of EDF and more specifically in the department of Study of Economy and Functioning of Energetic Systems (EFESE).

### 1.1.3 The SiSTEM model

In 2015-2017, in cooperation with University of Liège (Belgium), the SiSTEM model [1] (Simulation of Short-Term Electricity Markets) has been developed to specifically study short-term issues of electricity markets. This model is a multi agent optimisation tool simulating European short-term exchanges on electricity markets. Power companies interact with the day-ahead electricity market, the intraday market and the TSO by submitting market offers, providing their positions to the TSO and impacting the balance of the power system.

The energy market clears by maximizing the sum of the surpluses of the offers. The TSO reacts to unforeseen changes in production or consumption by activating
balancing energy to restore the balance of the system, using all the available balancing capacity, including reserve, which changes the final schedule 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 TSO. More explanations about this model can be found in this report on section 2.1.

In 2017, this simulation tool has been used to carry out a quantitative and detailed comparison of two different balancing gate closures times (a balancing gate closure time defined at 60 minutes ahead real-time or 15 minutes) [2].

The figure below gives an overview of the way SiSTEM works. Inputs (.csv files) and Outputs (.csv files) of the model can be understood from figure 1.2. There is also an interface to visualize the outputs graphically over the month. It is also possible to reduced the period to visualize.

![Figure 1.2: Inputs and Outputs of the SiSTEM model](image_url)
1.2 Problem Definition

Balancing has to assure equality between production and consumption at least cost. From figure 1.3, directions of imbalances can be understood from BRP’s perspective.

![Diagram showing actors’ imbalances](image)

**Figure 1.3: Actors’ imbalances (simplified) definition**

When the system is long (i.e. there is an excess of energy in the system), the TSO needs to activate downward balancing offers and when the system is short (i.e. there is a deficit of energy in the system), the TSO have to activate upward balancing offers. Upward and downward balancing offers are offered to the TSO by BSPs. The balancing market and the imbalance settlement have to give incentives for the different markets’ actors to take accurate decisions before the balancing gate closure time. According to Réseau de transport d’électricité (RTE) [3], the French TSO, imbalance prices should give incentives for BRP to be balanced as much as they can.

In table 1.1 the current way of calculating imbalance prices in France can be understood.
Table 1.1: Imbalance price settlement rule in France.

These imbalance prices are based on uses a correction factor $k = 0.05$ and the weighted cost of the activated balancing offers for $A^+$ (the weighted cost of the activated upward balancing offers) and $A^-$ (the weighted cost of the activated downward balancing offers). The factor $k$ induces an asymmetry in the imbalance prices.

The factor "k" is a parameter defined ex-ante in order to balance the consumption and the production of the energy compartment of the Balancing and Imbalance financial settlement based on historical chronicle. It was fixed until 31 December 2018 at 0.08 and from 1 January 2019 at 0.05. It can be revised up to 2 times per calendar year. Any revision is submitted by RTE to Commission de régulation de l’énergie (CRE) for approval.\(^1\)

The factor $k$ has two functions. First of all, it must cover a part of the TSO’s costs in order to avoid the TSO of having a negative revenue. TSO’s costs are due to upward balancing and positive imbalance settlement while TSO’s benefits are due to downward balancing and negative imbalance settlement. The second function of $k$ is to increase the incentives for the BRPs to reduce their imbalance volumes.

However, the CRE\(^4\), the French electricity regulation commission, considers that the factor $k$ that appears in the method of calculating imbalance prices does not allow a symmetrical imbalance price. Indeed, symmetrical prices should give incentive to BRPs to balance the system instead of balancing their own perimeter. CRE is in favour of deleting this factor for an European harmonisation. This issue will be addressed in 2019 as part of the harmonization proposal. The impact of $k$ on the different actor’s revenues has not been studied yet. Moreover, using the marginal cost of the activated balancing offers instead of the weighted average cost is another design that has to be investigated. Different ways of calculating imbalance prices have to be studied.

Moreover, actors’ balancing strategies related to the imbalance settlement have not been studied and must be investigated. If imbalance prices become more predictable, there is a risk that some actors try to take advantage of the imbalance settlement over other actors.

\(^1\)For a given calendar year $Y$, the factor $k$ is then revalued in $Y + 2$, to obtain a value $k’$ ex-post which then allows the Balancing and Imbalance financial settlement to reach the final financial settlement of RTE fixed by the CRE (in practice the targeted financial settlement is 0). RTE communicates to BRPs a forecast of the repayment of year $Y$ (estimation of $k’$) before the end of February $Y + 1$.  

\(^4\)The factor $k$ is revalued every two years at the end of偶数年.
1.3 Research question and Objective

Since the early 2000s, the organization of the European electricity sector has been constantly evolving following liberalization, the desire for harmonization between the different countries and to make the market fit for renewables. EDF, as an actor in the electricity market, must anticipate changes in the power system and model the associated effects, both for the short-term planning and for long-term investment decisions. For EDF’s perspective, this project would contribute to a better understanding of the impacts of short-term market design. This work has been carried out in close collaboration with the members of the R&D project team on electricity market design. It investigates the efficiency of different imbalance settlement pricing designs. This work relies on an on-going EDF research project on electricity balancing. The analysis focuses on the consequences of the method of calculating imbalance prices on the system and on the different types of actors. This report aims at evaluate the impact of different imbalance settlement designs on TSO’s revenues, actors’ revenues and actors’ behaviour. The main research question that is answered in this paper is: How do different imbalance settlement designs impact market participants behaviour and balancing market performance?

1.4 Overview of the report

This report will be divided in the following parts: Method in chapter 2, Results & Discussion in chapter 3 and Conclusion in chapter 4. In each part, analysis are undertaken under two different configurations. The first configuration of the work aims at evaluating the impact of imbalance price design on actors’ revenues without involving actors’ behaviour. The second configuration of the work aims at evaluating the impact of imbalance prices calculation on actors’ revenues while making actors adjust their behavior regarding the imbalance settlement and their imbalance position. Imbalance volumes and revenues will be analysed in both configurations.
Chapter 2

Method

The work has been carried out at EDF, Paris, France. The simulator SiSTEM [1] has been utilized with assistance of supervisors and documentation. In order to evaluate the impact of different imbalance settlement designs, analysis are undertaken under two different configurations. The first configuration of the work evaluates the impact of imbalance settlement design on actors’ revenues without involving actors’ behaviour. Indeed, actors’ strategies in this part aim at being always balanced even if being imbalanced would be profitable in some time steps. Imbalance prices will be then calculated after the simulation with post-processing. The second configuration of the work evaluates the impact of imbalance settlement design on actors’ revenues while making actors adjusting their behavior regarding the imbalance settlement and their imbalance position. To do so, actors’ balancing strategy have to be changed in the model. In this second configuration, imbalances prices are calculated during the simulation.

The analysis has to be divided in order to achieve the final results. First, the inputs (or base case) have to be clearly defined and explained in order to run the model. The same base case will be kept throughout the report. Then SiSTEM model has to be run 30 times in order to avoid simulation bias\(^1\) and to make statistic analyses on the results. Then, output data of the simulation has to be collected. Then data manipulations have to be carried out and at the same time statistic analyses on the results. Finally results will be discussed. The progression of work can be understood from figure 2.1.

\(^{1}\)To obtain results in a reasonable amount of time but still robust results with respect to difficult optimization problems, an average of 30 simulations is calculated in order to eliminate the randomness due to the simulation bias. 100 runs of the same simulation have been performed to compare the overall variable cost on average over 100 runs and over a limited number of runs. The average value obtained for 30 runs varies from the one of 100 runs by only 0.05%.
The SiSTEM model will be explained in section 2.1. Inputs of the study will be detailed in section 2.2. The relevant outputs of the simulation are balancing activation costs, the balancing volumes, the imbalance volumes and production volumes for each actor and finally the day-ahead prices of the simulated period (one month). Imbalance settlement designs will be explained in section 2.3. Balancing strategy modelisation will be explained in section 2.4. Finally, the final outputs will be explained in section 2.5 and presented and discussed in chapter 3.

### 2.1 The SiSTEM model

The SiSTEM model [1] is a multi-level optimization model of European short-term electricity markets, covering day-ahead and intraday exchanges as well as balancing activations and imbalance settlement. The balancing market modeled in this work corresponds to the Frequency Restoration Reserve (FRR) and the Reserve replacement (RR) mechanism. It explicitly represents several power companies and their interactions: each company makes offers, notifies its generation schedule to the TSO and ultimately proposes balancing services. After the balancing gate closure, the TSO activates balancing energy to restore the balance to the system using all balancing service offers proposed by market participants. Imbalance settlement implies bidirectional transactions between the TSO and power companies depending on the direction of their imbalance. This study focuses on only one zone as France represents one area.

#### 2.1.1 Time management

As explained in "SiSTEM, A Model for the simulation of short-term electricity markets"[1], time in the model is divided into simulation time steps. For the simulation of the different markets and action steps, the simulation horizon is divided into days. Each day is itself divided into a given number of time steps depending on the context. In a simulation, three time divisions exist: the day-ahead time steps,
the intraday timesteps and the general time steps. The latter is used by default and should lead to the higher granularity. For example, one day may be divided into 24 day-ahead time steps, 48 intraday time steps and 96 general time steps. This is illustrated in Figure 2.2 with two different time steps. The first one, in orange and denoted Time step 2/95, corresponds to the third time step of a day divided in 96 time steps or to the quarter starting at 00:30 and ending at 00:45. The second, in blue and denoted Time step 1/23, corresponds to the second time step of a day divided in 24 time steps. In addition to the time steps, the system also has the notion of period which is defined as a continuous set of time steps. Taking the example of Figure 2.2, Time step 1/23 corresponds to a period [Time step 4/95, Time step 7/95] in a day divided in 96 time steps.

![Figure 2.2: Example of two time steps, one which divide a day in 96 time steps and another which divides the day in 24 time steps.](image)

In each time step, the system runs the different actions. To each action corresponds two different timings, its decision time and its delivery time. These two notions are illustrated in Figure 2.3 assuming a day of 96 time steps, a neutralization delay of three time steps and half hour intraday time steps. First consider the delivery perspective, i.e. when actions have to be taken to deliver the energy in \( t \). This perspective is illustrated in Figure 2.3a for the time step \( t \) starting at 01:30 and ending at 01:45. The energy produced and consumed in time step \( t \) has first been traded the day before on the day-ahead market, before 12:00. Exchanges occurred in intraday throughout the intraday market until last clearing concerning time step \( t \). This clearing occurred at the end of the preceding half hour of the neutralization, i.e. in \( t - 5 \). The last balancing market clearing occurred right after the neutralization delay, therefore in time step \( t - 3 \). The activation of balancing for time step \( t \) occurs in the same period. Finally, the settlement of the imbalance penalty occurs afterwards, for instance in time step \( t + 1 \).

The decision perspective is illustrated in Figure 2.3b. In time step \( t \), the system activates the balancing for the current time step and makes the imbalance settlement of the previous time step. The balancing market clears in \( t \) for the time step \( t + 3 \). Finally, \( t \) is the last time step of an intraday period in which occurs the last clearing of the intraday market of the half hour period \([t + 5, t + 6]\). Note that, there is no intraday gate closure in time step \( t + 1 \).
To consider the different time horizons, the initialization of the system is done in two phases. First, the agent-based framework asks each market participant to submit their offers to the day-ahead market of the first day in their initialization. Second, the system starts running in a time step prior to the first period of the first day. In the example of Figure 2.3a, the system would start six time steps before: five for the clearing and one more to let the market participants send their first offers. In more general terms, the initialization delay accounts for the neutralization delay, increase to corresponds to intraday period, and two time steps, one for the clearing of the intraday market and one to let the market participants submit their last offers.

### 2.1.2 Energy markets models

As explained in [1], Energy markets are responsible for balancing production and consumption. Offers on different markets are communicated as bids $b$, consisting in a cost $\gamma_b$ in €/MWh and quantities $q_{b,t}$ in MWh for each market period $t$. In the SiSTEM model, purchases are represented by positive quantities and sales by negative quantities. In this model, the quantities are rounded to the closest integer leading to a minimum exchange of 1 MWh. For information, the minimum volume on the EPEX day-ahead energy market is 0.1 MWh.[1] The implementation in the model adds additional constraints to these bids as binary bid. It correspond to a binary decision: totally accepted or not. A bid may be restricted to be accepted only if another binary bid is accepted. These bids are respectively named child and parent bid.

#### Day-ahead energy market

The day-ahead offers are offered as bids and the bid should tell the volume to deliver, the marginal cost of the unit and a set of time steps. The bid can be accepted partially, totally or rejected and is referred as continuous bid. A bid that can only be accepted totally or rejected is referred as binary bid. Three clearing methods of the day-ahead energy market exist in the model. As explained in [1],"The first one, is the simple maximization of the welfare with prices defined by the cost of the most expensive accepted production offer. The second one is the classic version of the
clearing, where prices are defined by the dual of the equality constraints. Finally, a last version propose to integrate the prices directly into the primal problem leading to a primal-dual formulation.” The last one is used in the simulations that have been carried out. 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.

Intraday market

In SiSTEM, the implementation of the intraday market is by market sessions which take place every simulation time step while in most European countries, the Intraday market is a market updated continuously by market participants. This market in cleared in this model using the last version, of the three clearing methods of the day-ahead energy market, propose to integrate the prices directly into the primal problem leading to a primal-dual formulation. the formulation is flexible with respect to the number of market periods or their duration. The intraday market opens for the next day at 19:00 after the clearing of the day-ahead market In every simulation time step, the intraday market first clears the opened intraday market period. Indeed, 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. As explained in [1], ”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.”

2.1.3 Power company model

Power companies are market participants that make offers on the different market of the electrical system. Power companies owe the production units and the consumption in a single zone. The goal of each power company is to maximize its profit given its own portfolio of assets and clients. To maximize their profits, power companies continuously(each time-step) update their schedules and offers in the markets. In the model, decisions are updated in each simulation time step in four phases: forecasting, scheduling, trading and communicating balancing capacity.

Forecasts

As explained in [1], The sum of a power company exchanges and forecasts of the consumption and the non-dispatchable production including, in particular, the renewable production give the target production schedule of a power company. In SiSTEM, their realizations which are given as input to the model generate their predictions. ”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 \([W/10 + 4]\), where \(W\) is the number of simulation time steps per day.” The impact of the size of the smoothing window is shown in Figure 2.4.

![Figure 2.4: Effect of the size of the smoothing window on a deterministic forecast.](image)

According to a logarithmic function, the forecast error decreases with time toward a forecast of minimum error, \(\hat{p}_b\), given by a Gaussian law illustrated in Figure 2.5. “The prediction evolves from the worst forecast \(\hat{p}_w\) achieved in \(t - T\) of the realization \(p_t\), to the best forecast, \(\hat{p}_b\) achieved in \(t\). One last parameter provides the relative decay of the error \(\sigma\), arbitrarily set by default to 0.05. This evolution is influenced by the constant \(T\) and \(\sigma\) such that the forecast of \(p_t\) in time step \(\tau\), \(\hat{p}_t(\tau)\), satisfies for \(\frac{t - \tau}{T} \in [0, 1]\)"

\[
\hat{p}_t(\tau) = \hat{p}_b + \frac{\hat{p}_w - \hat{p}_b}{\ln \left( \frac{1 + \sigma}{\sigma} \right)} \ln \left( \frac{t - \tau + \sigma}{T} \right),
\]  

\[\text{(2.1)}\]
Figure 2.5: Evolution of the forecast error with the prediction delay.

All the parameters are settled in order to fit the forecast error that can be observed in France.

**Unit-scheduling and balancing strategy**

The units-scheduling task has to reach a coherent schedule at minimal cost while coordinating the production of individual units. The target schedule takes into account the forecasts, the energy exchanged on the different markets and also the balancing activation of the TSO. By solving the optimization problem, traditionally known as a unit commitment problem the coordination is made. This optimization problem is not solved by the TSO, which has no direct control over the production units, but by each power company independently. Then, if exchanges with other market participants are included, the target power to produce may be different from the consumption. Also, 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 2.4.

**Unit models**

In the units-scheduling problem presented above, each production unit $i$ has its own set of technical constraints $\mathcal{X}_i$ and a cost function $C_i(p_i)$. Technical constraints limit the output power $p_i$ and the upward and downward balancing capacity, $b_i^+$ and $b_i^-$. In the model, four types of production unit are implemented: basic units, thermal units, hydro-electric reservoirs and curtailable production. More information can be found in appendix 5.2.
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. SiSTEM also does the modeling of outages which applies to the basic and the thermal units. Outages in SiSTEM are given as input parameters. Each outage is characterized by a time of occurrence and a duration (see table 5.3 in appendix). These parameters describe a period in time step within the simulation model. An optional parameter may be used to define a notification time allowing to model maintenances. The last optional parameter is the relative availability of the unit in the range [0, 1] to model partial outages. By default, an outage is complete and the unit is completely unavailable. In the case of a partial outage, the production during the outage is zero if the unit was not scheduled to produce. If the unit is producing, the power production is given by the minimum between the the scheduled production at the beginning of the outage and the available production during the outage. The outage power given in output is defined as the difference between the corrected schedule and the realization. The value is often positive but can be negative in specific cases. For instance, take a 900 MW production unit with the production plan 400, 300, 200 MW. If this unit faces a complete outage, the outage powers are respectively 400, 300, 200 MW. Now consider a partial outage with an available power of 600, the power production during the outage will be stuck at 400 MW. The unit produces more than schedule and the outage powers are respectively 0, −100, −200 MW. Note that the outage power corresponds to the opposite to the imbalance that will be accounted.

When an outage occurs, the power company informs the system operator. For all this period, the system operator will not expect that the unit would be able to provide balancing capacity or reserves. The outage power is computed such that future imbalances can be forecasted. This future imbalance must be compensated either by the power company or by the system operator. The part compensated by the system operator is denoted as validated in the output. This validated part corresponds to the production within the neutralization plus an outage tolerance period. By default, this outage tolerance period is of 15 minutes.

In each time step, power companies have to provide their balancing capacities for different horizons. A power company is called upon two times in real-time time, i.e. in one simulation time step for the current simulation time step. First, before balancing activation to compute its realization. The realizations of all market participants provide the system imbalance. Second, after balancing activation such that the activation requests are processed. In particular, the realizations of production units are adjusted.

For a power company, computing its realization implies prompting outages and replacing forecasts by their realizations given as input parameters. This optimization problem minimizes deviations from the unit schedule subject to the usual constraints of the production unit. Deviations could still occur due to the explicit balancing offers which can be unfeasible to satisfy.
2.1.4 Balancing mechanism model

This section details the balancing mechanism from the system operator point of view. The model focuses on the balancing energy from the frequency restoration reserve and the replacement reserve which are manual mechanisms to restore balance to the system. Before real-time, the system operator forecasts its balancing requirements. Given the balancing requirements, the system operator needs to forecast the future imbalances of the system. The forecast mechanism used by the system operator differs from the one of the power companies. The model makes the difference between the imbalance of an actor and the imbalance of the system. The system imbalance is given by the sum of the realization of each power company. The computation of this imbalance is the first operation in a simulation time step.

In this model, the system operator directly forecasts the balance of the whole system rather than forecasting the consumption 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.

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 and then activates balancing energy based on decisions taken previously.

A legal entity responsible for the balance of its intakes and off-takes is called a balancing responsible party BRP. 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. 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 energy on the Day ahead market and the intraday market 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. Imbalance prices are computed in the SiSTEM model[1] at the end of each imbalance settlement period. Imbalance volumes are not only due to forecast errors. They can have different origins as forecast errors, units’ dynamic constraints, illiquidity of day ahead and intra-day markets, outages or voluntary imbalance from actors.
2.2 The Study Case

The inputs used to run the model correspond to a simplified and stylized representation of the French electrical production (Mix "nuclear, gas, renewable") and consumption assets as explained in [1]. EDF’s request was to run this study with the same base case as in [1].

"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 1/20." The Demand profile (in MW) for Actor 1 can be seen on figure 2.6 for the first three days on the simulated period. In the SiSTEM model, the Demand is seen as a negative production. In order to correctly read the graphic, one has to keep in mind that the lower the curve is the higher demand is.

![Figure 2.6: Demand profile (in MW) of the 3 first simulated days for Actor1](image)

The numbers given in figure 5.1 in appendix 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 2.1.4. [1]

The base case simulates a winter month: January. The input data for Demand and renewable production are representative of winter conditions. Indeed, data corresponds to meteorological conditions from January 3, 2014 through February 3,
2014. This lead to a maximum and minimum net demand of 4.81 GW and 2.65 GW, respectively. The photovoltaic generation (in MW) profile can be seen on figure 2.7 for the first three days on the simulated period.

![Photovoltaic profile (in MW) of the 3 first simulated days](image)

Figure 2.7: Photovoltaic profile (in MW) of the 3 first simulated days

The simulation time step is a quarter of hour as well as the intraday time step and the time step for balancing. The day-ahead time step is one hour. The chosen TSO is similar to the potential French one in 2021 [2]. The TSO makes reactive decisions and closes the balancing gate 15 minutes before real time. There is no short-term reserve mechanism. The imbalance settlement time step is a quarter of hour. Four imbalance settlement designs will be investigated. France is one trading area. It should be noted that inputs are not all representative of France but tends to look like the French electrical assets in 2021. The study case is designed to be as closed as possible to real functioning of power systems but the detailed cost and technical parameters of generation units should not be considered as representative of a specific real power system. There are four with production and consumption shares as seen in figure 2.8.
Actor 1 and Actor 2 are both producers and retailers but Actor 1 is the biggest one. Actor 1 is a producer and a retailer operating all the nuclear power plants and the majority of hydro-electric reservoir 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 only a retailer and Actor 4 is a renewable producer. Detailed distribution of the capacity between the actors of the studied case in MW can be found in appendix chapter 5 figure 5.1.

In the first configuration of the study, actors will have a strategy called ”Always Balance” in the model which gives incentives to BRP to balance themselves as much as they can. In the second configuration of the study, actors will be more ”strategic”, which means that they can decide to be imbalanced if it is economically interesting for them. Details on the second part of the study will be given in section 2.4.

As stated in [1], Capacities of figure 5.1 are divided into production units following the parameters in appendix chapter 5 of figure 5.2. 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. [1] Technology’s variable costs and technology’s startup costs of the thermal power plants can be seen on figure 2.9 and 2.10 respectively.
As explained in [1], "dispatchable hydro-electric production from reservoirs is divided into two parts, the manually-controlled one and the remote-controlled one. The difference between the two is the delay of notice which is respectively of three
hours and five minutes.” Their parameters are taken from French historical data and scaled to 1/20 to match the installed capacities given in figure 5.1. 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€/(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. 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.

Variable costs of the units are drawn from 5%-wide uniform distribution around values given figure 5.2. The parameters of their outages are given in appendix chapter 5 figure 5.3. The deratings correspond to outages adequate for the scale of the system, i.e. 300 MW. Details on outages at the end of the simulation can be found in appendix on section 5 on figure 5.4.

The variable cost of the renewable production is arbitrarily set to zero. Wind and PV are modelled as non dispatchable generation (i.e. the generated volume is defined through their load factor for each simulation time step.)

In practice, nuclear power plants have a limited flexible capacity around its steady-state operation point. In this base case, nuclear A provides up to 11.5% of its maximum power, corresponding to 150 MW, for downward reserve without any constraints. In the following, this flexibility is referred to as flexible nuclear to differentiate if from a shift of operational point.

As shown in [1], figure 2.11 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.[1]
2.3 Imbalance settlement designs

This study will evaluate four different ways to calculate imbalance prices.

The default rule in the model uses a pricing version with a correction factor $k = 0.05$ and the weighted cost of the activated balancing offers for $A^+, A^-$. The TSO “pay as bid” the balancing offers as it is done in France nowadays. Balancing offers are at the price of the marginal variable cost of the unit that offers balancing.

The aim of this study is to evaluate the impact of moving from the actual design (non-symmetric imbalance prices) to a design with symmetric imbalance prices. Indeed, if imbalance prices are symmetric, BRPs are less penalized when they are in negative imbalance while the system is long and they earn more when they are in positive imbalance while the system is short. That is why, symmetric imbalance prices give incentives to BRPs to balance the system instead of balancing themselves.

To achieve symmetric imbalances prices, three alternatives will be investigated. An alternative is to set the correction factor $k = 0$. According to CRE[4], “this alternative aims at giving more incentives for producers and retailers to balance the system instead of balancing themselves.”

Another alternative to define imbalance settlement design is to use the maximum balancing activation offer for $A^+, A^-$ with a correction factor $k = 0$ while the TSO “pay as cleared” the balancing offers. This design is proposed by the European commission and is used in the Netherlands and in the Nordic countries. According to CRE[4], ”this alternative also aims at giving more incentives for producers and retailers to balance the system instead of balancing themselves.”

A last alternative recently proposed by CRE to get symmetrical imbalance prices while keeping a correction factor k is to change the imbalance prices matrix. With the weighted cost of the activated balancing offers for $A^+, A^-$, the matrix would be as defined in table 2.1. This alternative aims at giving more incentives for producers and retailers to balance the system instead of balancing themselves as the two...
previous alternatives but it assures a positive revenue for the TSO in order to avoid the TSO being in deficit.

<table>
<thead>
<tr>
<th>Imbalance prices</th>
<th>System imbalance</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>BRP’s imbalance</strong></td>
<td><strong>Long</strong></td>
</tr>
<tr>
<td>Positive (TSO pays BRP)</td>
<td>$A^- (1 - k)$</td>
</tr>
<tr>
<td>Negative (BRP pays TSO)</td>
<td>$A^- (1 - k)$</td>
</tr>
</tbody>
</table>

Table 2.1: Imbalance price settlement: CRE proposal

This will lead to four different imbalance settlements designs to evaluate.

- WAP k0.05: (French current one) : Weighted average cost of the activated balancing offers; k=0.05; TSO pays as bid balancing offers
- WAP k0: (first proposition of CRE): : Weighted average cost of the activated balancing offers; k=0; TSO pays as bid balancing offers
- Marginal k0: (EU/ACER proposition): : Marginal cost of the activated balancing offers; k=0; TSO pays as cleared balancing offers
- CREWAP k0.05: (second proposition of CRE): Different matrix with weighted average cost of the activated balancing offers; k=0.05; TSO pays as bid balancing offers

### 2.4 Modelling Balancing Strategy

This section presents how balancing strategy is modelled. The aim of this modelling was to evaluate the actors’ behaviour if they adjust their behavior regarding the imbalance prices.

In order to be able to do this study, a new actor’s strategy has been added on the SiSTEM model.

Balancing strategies can be defined thanks to parameters that appear in the optimization problem (2.2), traditionally known as a unit commitment problem. This aims at minimizing the production cost as well as the imbalance cost. This optimization problem is solved by each market participants for each time step. The cost function depends on the market participant’s units as explained in 2.1.3. In this cost function binary unit commitment variables are present. More explanations can be found in appendix section 5.2.

#### Sets

- $S$: Balancing periods
- $T$: Time steps
- $U$: Production units
- $X_i$: Production units constraints
Parameters
\[ C_i(p_i) \] Cost function of the production unit
\[ \Delta \] Length of a time step
\[ E_t \] Exogenous production
\[ L_{i,t}^+, L_{i,t}^- \] Upward and downward reference for important deviation
\[ \kappa_{i,+}^b, \kappa_{i,-}^b \] Upward and downward important deviation prices
\[ \mu_{i,+}^b, \mu_{i,-}^b \] Upward and downward imbalance cost
\[ Q_t \] Target power to produce
\[ R_{i,t}^+, R_{i,t}^- \] 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
\[ I_s^+, I_s^- \] 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 \( p_i = \{ p_{i,t}, \forall t \in T \} \) and \( b_i = \{ b_{i,t}^+, b_{i,t}^-, \forall t \in T \} \).

Optimization problem
\[
\min \sum_{i \in U} C_i(p_i) - \sum_{s \in S} (\mu_{i,+} I_{s^+}^s + \mu_{i,-} I_{s^-}^s) - \sum_{t \in T} (\kappa_{i,+} K_t^+ + \kappa_{i,-} K_t^-) 
\quad \text{subject to}
\]
\[
(p_i, b_i) \in \mathcal{X}_i \quad \forall i \in U \tag{2.2b}
\]
\[
\sum_{i \in U} p_{i,t} + E_t = Q_t + D_{t}^+ + D_{t}^- \quad \forall t \in T \tag{2.2c}
\]
\[
I_{s^+}^s + I_{s^-}^s = \sum_{t \in S} (D_{t}^+ + D_{t}^-) \Delta \quad \forall s \in S \tag{2.2d}
\]
\[
K_{t,+}^+ \geq D_{t}^+ - L_{t}^+ \quad \forall t \in T \tag{2.2e}
\]
\[
K_{t,-}^- \leq D_{t}^- - L_{t}^- \quad \forall t \in T \tag{2.2f}
\]
\[
\sum_{i \in U} b_{i,t}^+ = R_{i,t}^+ \quad \forall t \in T \tag{2.2g}
\]
\[
\sum_{i \in U} b_{i,t}^- = R_{i,t}^- \quad \forall t \in T \tag{2.2h}
\]

with \( (p_{i,t}, b_{i,t}^+, b_{i,t}^-) \in \mathbb{R}^+ \times \mathbb{R}^+ \times \mathbb{R}^- , \forall (i, t) \in U \times T ; \) \( (D_{t}^+, K_{t}^+, D_{t}^- , K_{t}^-) \in (\mathbb{R}^+)^2 \times (\mathbb{R}^-)^2 , \forall t \in T ; \) \( (I_{s^+}^s, I_{s^-}^s) \in \mathbb{R}^+ \times \mathbb{R}^- , \forall s \in S \).

The individual constraints of the production units are summarized by equation (2.2b) where for each unit \( i \), \( p_i \) 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 section 5.2.

Power balance is ensured by equality (2.2c), 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 (2.2d) 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 (2.2e)-(2.2f). 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 (2.2g)-(2.2h).

In order to define a balancing strategy, the parameters $\kappa_b^+, \kappa_b^-, \mu_b^+, \mu_b^-$ have to be modified. In this study, important deviations are not considered differently from the other deviations. When $\kappa_b^+, \mu_b^+$ are modified, actors will see it as it was the upward imbalance price modified. When $\kappa_b^-, \mu_b^-$ are modified, actors will see it as it was the downward imbalance price modified. For the first part of the study, $\kappa_b^+, \kappa_b^-, \mu_b^+, \mu_b^-$ were set to high values in order to give incentives to market participants to be always balance. $\kappa_b^+,$ $\mu_b^+$ were equal to -3000 and $\kappa_b^-, \mu_b^-$ were equal to 3000.

The second part of the study aims at making power companies adjust their behavior to take into account the imbalance settlement. To do so, an average of the 4 last imbalance prices is calculated. Indeed, these are the last imbalance prices seen in the hour before. It is really rare that imbalance volume change drastically in four time steps. What is more, the imbalance direction changes in more than four time steps (six in average). The four last imbalances prices will then give information to BRPs of the trend of the imbalance direction, and imbalance prices.

With $t$ the current time step, $IP^-$ the negative imbalance price and $IP^+$ the positive imbalance price:

$$\kappa_b^-, \mu_b^- = \frac{IP^-(t-1) + IP^-(t-2) + IP^-(t-3) + IP^-(t-4)}{4}$$

and

$$\kappa_b^+, \mu_b^+ = \frac{IP^+(t-1) + IP^+(t-2) + IP^+(t-3) + IP^+(t-4)}{4}$$

All BRPs are then settled for each MWh deviation from scheduled energy with that approximation of future imbalance prices (in €/MWh), which gives them new incentives to adapt their behaviour regarding portfolio, balancing for the next time step. BRPs’ behaviour determines balancing market results, and those results influence BRPs again and again each time step.

This strategy helps to understand how imbalance settlement design impacts market participants behaviour. Then it will be also investigated how imbalance settlement design can affect market actors’ revenues, i.e. producers, retailers and TSO if producers and retailers adjust their behavior regarding imbalance prices depending of the imbalance settlement design.
2.5 Final outputs

This section presents how the final results are investigated. Imbalance Settlement design will affect imbalance volumes, the overall cost of the system and market actors’ revenues, i.e. producers, retailers and TSO. For the second configuration of the study, imbalance settlement design will also have an impact on market actors’ behaviour. The impact of imbalance settlement will be only studied on Actor 1 (the biggest) and Actor 2 because they are both producers and retailers. They are comparable actors but with different sizes.

2.5.1 Impact of imbalance settlement on overall cost and imbalance volumes

From the social welfare point of view, the efficiency of the balancing management options can be estimated through the overall variable costs to serve the electricity demand profile as the demand is inelastic. [2] The overall variable cost takes into account the variable fuel costs, the start up costs of the units, the valuation of the hydro stock and the valuation of the energy not served. Overall variable costs will be investigated through both configurations and imbalance settlement designs. Imbalance volumes will also be investigated through both configurations and imbalance settlement designs and will be compared to the production volume P and the consumption volume C of Actor 1 and 2.

2.5.2 Impact of imbalance settlement on the Transmission System Operator

The TSO’s total revenues are the sum of the revenues due to Balancing activation and the revenues due to imbalance settlement. Charges for the TSO are upward Balancing and positive imbalance settlement whereas revenues for the TSO are downward Balancing and negative imbalance settlement. Charges and Products for the TSO can be understood on figure 2.12. The TSO’s financial settlement is the sum of charges and revenues. Financial flows for the TSO will be investigated.
2.5.3 Impact of imbalance settlement on producers and retailers

The impact of imbalance settlement will be only studied on Actor 1 (the biggest) and Actor 2 because they are both producer and retailer. They are comparable actors but with different sizes. The impact of the imbalance price calculation will be analyzed throughout 2 indicators.

- **I1**: Imbalance cost / Imbalance cost if they were settle with spot price (DA)

- **I2**: Imbalance cost / (consumption + production) (€/MWh)

The Imbalance costs as well as consumption and production are the sum of each time step for the whole simulated month. I1 indicates if being imbalanced is more or less expensive than being balanced. I2 indicates the imbalance cost for one MWh produced or consumed and then tells the weight of imbalance in the economic settlement of actors.
Chapter 3
Results and Discussion

Output of simulations are obtained after 15 hours of computation (around 18 seconds for each time steps) \(^1\). To obtain results in a reasonable amount of time but still robust results with respect to difficult optimization problems, an average of 30 simulations(with the same inputs) is done in order to eliminate the randomness due to the simulation bias.[1].

For the first part of the study, section 3.1, 30 simulations have been run and then imbalance prices have been calculated with post processing to evaluate the impact on market participants’ revenues whereas for the second part of the study, section 3.2, imbalance settlement designs have been settled in the model SiSTEM and 30 simulations have been run for each design in order to evaluate the impact of the design on actors’ behaviour.

3.1 Analyse of imbalance settlement designs (assuming actors always balanced)

3.1.1 Impact of imbalance settlement on overall cost and imbalance volumes

In this first configuration (post processing), the overall variable cost is equal to 36 636 k\(€\). Volumes of imbalances can be found on table 3.1 with C the consumption and P the production of each actors for Actors1 and Actor2 but P and C represent the production and the consumption of the whole system for the system. One has to keep in mind that, as explained in section 2.1.4, imbalance volumes are not only due to forecast errors. They can have different origins such as units’ dynamic constraints, illiquidity of DA and intraday markets, outages or also voluntary imbalance from actors. In this configuration on the study, imbalances from actors are not voluntary.

\(^1\)The model is implemented in Python 3 using the Pyomo library. 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 an 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.[1]
Looking at 3.1, it can be said that actors have more negative than positive imbalances. Actor 1 is more imbalanced in net volumes because of its size but compared with its portfolio, the imbalance percentage is lower than for Actor 2 thank to its expansion rate (i.e. its number of units and flexibility). System imbalance volumes (sum in absolute value) represent around 1% of the sum of consumption and production of the month. The percentage for the system is closer to the percentage of Actor1 as Actor1 owes must of the production and consumption.

3.1.2 Impact of imbalance settlement on the Transmission System Operator

Revenues for TSO are presented in table 3.2 as the sum of revenues for each time step for the simulated month. Balancing revenues are settled for each time step with the balancing volume and the upward balancing cost when the balancing volume is positive or the downward balancing cost when the balancing volume is negative. Upward balancing implies a negative revenue for the TSO whereas downward balancing implies a positive revenue for the TSO.

Imbalance settlement revenues are settled for each time step with imbalance volumes of each actors and the negative or positive imbalance prices depending on the direction of imbalance of each actors. The total revenue is the sum of the balancing revenue and the imbalance settlement revenue.

The economic counter activation revenue is the difference between the actual Balancing revenue and the balancing revenue if the TSO would not have made economic counter activations.
Looking at the table 3.2, it can be said that the actual design that is settled in France, WAP k0.05, is the one which give the biggest revenue for the TSO. On the other hand, Marginal k0, is the design that give the least revenue for the TSO. In every designs, the TSO’s revenue is positive and the money should be redistributed. Positive revenues are due to the factor k and economic counter activations.

The objective of the TSO in the imbalance settlement 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 TSO 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. This may be forbidden in some countries. The default choice in the implementation of SiSTEM is to allow the TSO economic counter-activations, therefore improving the economic efficiency of the system. The mechanism of economic counter-activations is explained in figure 3.1.

Economic counter activations performed by the TSO under SiSTEM model are mainly due to two reasons. The first reason is related to offers that are based on opportunity cost. Indeed, offers that allow the TSO to perform economic counter activations are offers from the technology “reservoir remote” which is a hydro power unit. Market participant bidding for this type of unit have to include in the offer the opportunity cost of releasing the water later, i.e. outside of the simulated time horizon. A scenario releasing more water should therefore be seen as more costly than another. When offering downward balancing energy, this technology will ask to pay to the TSO to be able to release the water later. On the other hand, when offering upward energy, this technology will ask to be paid the lost future revenue (i.e. the opportunity cost of not releasing the water later). As opportunity cost is not always perfectly aligned with marginal cost of the system at the time period, economic counter activations could appear. The second reason is related to the imperfect functioning of intraday markets in the SiSTEM model. BRPs try to optimize their own portfolio without looking at the other BRPs.

<table>
<thead>
<tr>
<th>TSO’s revenues</th>
<th>Imbalance settlement designs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>WAPk0.05</td>
</tr>
<tr>
<td>Balancing Revenue</td>
<td>-25 k€</td>
</tr>
<tr>
<td>Imbalance Settlement Revenue</td>
<td>136 k€</td>
</tr>
<tr>
<td>Total Revenue</td>
<td>111 k€</td>
</tr>
<tr>
<td>Counter activations Revenue</td>
<td>57 k€</td>
</tr>
<tr>
<td>Total without counter activation</td>
<td>54 k€</td>
</tr>
</tbody>
</table>

Table 3.2: Transmission System Operator revenue (assuming actors always balanced)
The TSO’s Balancing financial statement will be as followed:

- Without economic counter-activation
  \[-5\text{MW} \times 25\text{	exteuro/MWh} = -125\text{	exteuro/h}\]

- With economic counter-activation
  \[-9\text{MW} \times 25\text{	exteuro/MWh} + 4\text{MW} \times 30\text{	exteuro/MWh} = -105\text{	exteuro/h}\]

By doing this economic counter activation, the TSO make a gain of 20 €/h. The economic counter activations will not have any impact on the imbalance financial settlement because imbalance prices will be calculated with the upward balancing cost $A^+$ as the system is still short.
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.

First of all, having a $k$ equal to 0 is not synonymous of the TSO revenue equal to 0, this is due to economic counter activations that the TSO does when the downward balancing price is higher than the upward balancing prices. It can be asked how to redistribute this possible surplus as a TSO must not get any profits. Second of all, benefits coming from economic counter activations are consequent. It can be asked if it is a specificity of SiSTEM’s TSO or it may be linked with the balancing strategy ”Always balanced” of actors. It is difficult to obtain data to know if counter activation volumes are realistic or not. In general it can be said that compared to WAP $k_{0.05}$, having symmetrical imbalance prices, the reduction of $k$ or moving from average to marginal reduce the net financial result of the TSO.

3.1.3 Impact of imbalance settlement on producers and retailers

Figure 3.2 compares the results for the first indicator $I_1$ with the four imbalance settlement designs.

![Figure 3.2: Imbalance cost / Imbalance cost if they were settle with spot price(DA) (assuming actors always balanced)](image)

Reading key: $I_1 < 1$

Actors would make benefits being imbalanced (imbalance prices does not encourage
Actors would have done better to buy or sell on the DA market (Imbalance prices encourage actors to be balanced)

Looking at the figure 3.2, it can be said that increasing the k factor or moving from average to marginal encourage actors to be balanced i.e. it penalizes actors if they are not balanced. Actor 1 is more impacted by designs modification.

If WAP k0 is chosen, incentives to be balanced are reduced. In theory, these incentives should help to balance the system. In our case, Actor 1 being most of the time the imbalance direction creator, is not able to take advantage of symmetrical imbalance price. Indeed, with WAP k0, the imbalance prices do not encourage actors to be balanced and Actor 2, much smaller than Actor1, would intentionally be in the opposite direction of the system imbalance in order to make benefits and also help the system to be balanced. If Actor 1 would like to do that, it would probably change the imbalance direction.

Figure 3.3 compares the results for the second indicator I2 with the four imbalance settlement designs.

![Figure 3.3: Imbalance cost/ (consumption + production) (€/MWh) (assuming actors always balanced)](image)

Looking at the figure 3.3, it can be said that for all the designs, the imbalance cost of Actor2 is more impacted by imbalance settlement than the imbalance cost of Actor1. This can be explained by the difference of size(in MW) between the two power companies and also by the number of generation assets difference. Indeed, Actor 2 has less flexibility than Actor1 and with more different units, Actor 1 can take advantage of its economic of scale. It can be said that the weight of the imbalance cost is higher for smaller actors.
As the strategy of actors is to be always balanced, and the results are coming from post processing, both Actor1 and 2 reduce their imbalance costs with WAP k0.

### 3.2 Analysis of the impact of imbalance settlement designs on the Actors’ balancing strategy and behaviour

For this configuration of the study, imbalance settlement designs have been settled in the model SiSTEM and 30 simulations have been run for each design in order to evaluate the impact of the design on actors’ behaviour.

#### 3.2.1 Impact of imbalance settlement on overall cost and imbalance volumes

In the first configuration of this study (post processing and ”always balance” strategy, i.e. balancing the portfolios no matter the cost), the overall variable cost was equal to 36 636 k€. The overall variable cost takes into account the variable fuel costs, the start up costs of the units, the valuation of the hydro stock and the valuation of the energy not served. In theory, make actors adjust their behavior regarding the imbalance settlement should improve the overall cost of the system as they will try to help the system or at least reduce their own cost. This is confirmed by the results. Indeed, leaving market participants to balance according to their expectation of imbalance prices reduces the overall variable cost of around 1.6 %. The overall variable cost for WAP k0.05 is of 36 047 k€, for WAP k0 is 36056 k€, for Marginal k0 is 36070 k€, and for CREWAP k0.05 it is 36 064 k€. Unfortunately, for this second configuration, the difference of overall costs between designs can not be used to rank the designs as it is smaller than the simulation bias [1]. Overall variable costs of different configurations and designs can be seen in figure 3.4.
The reducing of the overall variable cost between configuration 1 and configuration 2 can be explained by the energy shares differences of each production technology between the two configurations and the corresponding average production costs given in Table 3.3. The average costs provided in this table include start-up costs. With a better understanding of the imbalance settlement, market participants succeeded to replace CCGT by Nuclear, by a better scheduling on the day ahead and intraday markets, which improved the overall variable cost.

<table>
<thead>
<tr>
<th>Energy share (Config1)</th>
<th>Energy share (Config2)</th>
<th>Average cost [€/MWh]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>79.2%</td>
<td>10.80</td>
</tr>
<tr>
<td>CCGT</td>
<td>8.2%</td>
<td>31.76</td>
</tr>
<tr>
<td>Coal</td>
<td>6.4%</td>
<td>20.52</td>
</tr>
<tr>
<td>Hydro</td>
<td>1.5%</td>
<td>50.00</td>
</tr>
<tr>
<td>Renewable</td>
<td>4.6%</td>
<td>0.00</td>
</tr>
<tr>
<td>OCGT</td>
<td>0.1%</td>
<td>242.22</td>
</tr>
</tbody>
</table>

Table 3.3: Breakdowns by production technology of the energy share for configuration 1 and configuration 2 and short term production costs

Volumes of imbalances for each design of configuration 2 can be found on tables 3.4, 3.5, 3.6 and 3.7 for design 1, 2, 3 and 4 respectively, with C the consumption and P the production. One has to keep in mind that, as explained in section 2.1.4, imbalance volumes are not only due to forecast errors. They can have different origins such as units’ dynamic constraints, DA and intraday markets not liquid enough,
outages or also voluntary imbalance from actors. In this second configuration of the study, imbalance from actors can be voluntary.

<table>
<thead>
<tr>
<th>Positive Imbalance (MWh)</th>
<th>Negative Imbalance (MWh)</th>
<th>% Imbalance /(C+P)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actor1</td>
<td>11403</td>
<td>-25406</td>
</tr>
<tr>
<td>Actor2</td>
<td>2483</td>
<td>-11187</td>
</tr>
<tr>
<td>System</td>
<td>25440</td>
<td>-39869</td>
</tr>
</tbody>
</table>

Table 3.4: Imbalance volumes (configuration2 and design1)

<table>
<thead>
<tr>
<th>Positive Imbalance (MWh)</th>
<th>Negative Imbalance (MWh)</th>
<th>% Imbalance /(C+P)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actor1</td>
<td>10217</td>
<td>-34622</td>
</tr>
<tr>
<td>Actor2</td>
<td>4764</td>
<td>-24470</td>
</tr>
<tr>
<td>System</td>
<td>26536</td>
<td>-62417</td>
</tr>
</tbody>
</table>

Table 3.5: Imbalance volumes (configuration2 and design2)

<table>
<thead>
<tr>
<th>Positive Imbalance (MWh)</th>
<th>Negative Imbalance (MWh)</th>
<th>% Imbalance /(C+P)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actor1</td>
<td>12031</td>
<td>-32036</td>
</tr>
<tr>
<td>Actor2</td>
<td>5313</td>
<td>-21023</td>
</tr>
<tr>
<td>System</td>
<td>28276</td>
<td>-56535</td>
</tr>
</tbody>
</table>

Table 3.6: Imbalance volumes (configuration2 and design3)

<table>
<thead>
<tr>
<th>Positive Imbalance (MWh)</th>
<th>Negative Imbalance (MWh)</th>
<th>% Imbalance /(C+P)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actor1</td>
<td>15236</td>
<td>-27172</td>
</tr>
<tr>
<td>Actor2</td>
<td>11564</td>
<td>-17830</td>
</tr>
<tr>
<td>System</td>
<td>38273</td>
<td>-48248</td>
</tr>
</tbody>
</table>

Table 3.7: Imbalance volumes (configuration2 and design4)

In general, it can be said that imbalance volumes are higher with configuration 2 than with configuration 1. This is because actors can choose deliberately to be imbalanced (they think they will be less penalized than with configuration 1). It can be noticed that with symmetrical imbalance prices (Design 2, 3 and 4 compare with Design1), actors have more imbalance volumes compare to their own production and consumption. This is because they are less penalized than with Design1 (non-symmetric). However, in theory we would expect that with symmetrical imbalance prices (Design 2, 3 and 4 compared with Design1), the imbalance of the whole system would get reduced. This is the opposite that happened. That can be explained in different ways. The first hypothesis is that the Intraday market in SiSTEM is not
liquid enough and that transactions that would have been made on the intraday market in the reality are made on the balancing market in the SiSTEM model. The second hypothesis is that both Actors 1 and 2 are solving the unit commitment independently. When Actor 2 wants to make benefit by being imbalanced in the opposite direction of the system imbalance (in order to help the system), Actor 1 wants the same and will change the direction of the system.

3.2.2 Impact of imbalance settlement on the Transmission System Operator

Revenues for TSO are presented on table 3.8 as the sum of revenues for the simulated month.

<table>
<thead>
<tr>
<th>TSO’s revenues</th>
<th>Imbalance settlement designs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>WAPk0.05</td>
</tr>
<tr>
<td>Balancing Revenue</td>
<td>-613 k€</td>
</tr>
<tr>
<td>Imbalance Settlement Revenue</td>
<td>699 k€</td>
</tr>
<tr>
<td>Total Revenue</td>
<td>86 k€</td>
</tr>
<tr>
<td>Counter activations Revenue</td>
<td>11 k€</td>
</tr>
<tr>
<td>Total without counter activation</td>
<td>75 k€</td>
</tr>
</tbody>
</table>

Table 3.8: Transmission System Operator revenue (assuming actors adjusting their behavior regarding imbalance settlement)

Looking at the table 3.8, it can be noticed that the sum over the month of balancing revenue and imbalance settlement revenue increased a lot when actors adjust their behavior regarding imbalance settlement. This can be explained by higher imbalance volumes. As actors can make themselves imbalanced, there are more imbalance volumes and so on more financial flows with the TSO. However, the net financial result of the TSO is reduced with respect to the results with configuration 1. The main reason for this reduction is that economic counter activations benefits are also reduced. This indicates a better performance of the intraday market. Indeed, economic counter activation can be seen as a default of the intraday market when this one is not liquid enough. The second configuration of this study is then more realistic.

It should also be noted that with k=0 (i.e. designs 2 and 3) financial flows (Balancing revenue and Imbalance settlement revenue) increase a lot compared to designs 1 with k=0.05. This can be explained by the volume effect. Indeed, imbalance volumes are much higher with designs 2 and 3 than with design 1. CREWAP k0.05 also results in a higher amount of imbalances than design1 but as the imbalance prices matrix is changed, financial flows do not increase.
3.2.3 Impact of imbalance settlement on producers and retailers

Figure 3.5 compares the results for the first indicator I1 with the four imbalance settlement designs.

Looking at figure 3.5, it can be said that actors’ balancing strategy is working. Market participants are adjusting their behavior regarding the imbalance settlement prices and change their positions on day ahead and intraday markets as well as their scheduling in order to optimize their level of imbalance. I1 is above 1 but still really close to 1 for all designs. This shows that actors buy on the DA market when it would be too expensive to be imbalanced and stay imbalanced when it is seen as economically viable. However, as each actors try to optimize their own portfolio without looking at the other BRPs, the indicator I1 stays above 1.
Figure 3.6 compares the results for the second indicator I2 with the four imbalance settlement designs.

Figure 3.6: Imbalance cost/ (consumption + production) (€/MWh) (assuming actors adjusting their behavior regarding imbalance settlement)

Looking at the figure 3.6, it can be seen that when actors adjust their behavior regarding the imbalance settlement, the weight of the imbalance cost is higher than if they try to be always balanced for Actor 1 and 2. This can be explained by the volumes. Indeed, imbalance volumes increase when market participants adjust their behavior regarding imbalance settlement. Particularly negative imbalances increased a lot compared with configuration 1. BRPs pay the TSO for negative imbalance. The weight of the imbalance cost can also be understood that, as each actors try to optimize their own portfolio without looking at the other BRPs, they must sometimes take non-economically viable decisions. Actor 2 is more impacted by changes of imbalance settlement designs than Actor 1. Indeed, the reduction of k or moving from average to marginal pricing increases imbalance costs.

Looking at the figure 3.2, it could have been expected that Actor 2 takes advantage of imbalance settlement with WAP k0 (at least, advantage in reducing imbalance settlement costs). However, the opposite happened. This can be explained by the fact that both actors 1 and 2 are solving the unit commitment independently. When Actor 2 wants to benefit by being imbalanced in the opposite direction of the system imbalance (in order to help the system), Actor 1 wants the same and will change the direction of the system. That way, both actors are penalized. If we consider that Actor 1 is blind about the fact that it makes the system imbalance direction, CREWAP k0.05 is the modality which decreases penalties.

Compared to the actual design in France, the reduction of k or moving from average to marginal pricing increases the imbalance cost but CREWAP k0.05 decreases the imbalance cost.
Chapter 4

Conclusion and Further Research

This report aims at answering the question: How do different imbalance settlement designs impact market participant behaviour (Actor 1 and 2) and balancing market performance (including the TSO’s financial settlement). The report investigated four imbalance settlement designs on a study case where there is a predominant market participant. The following statements have been highlighted.

When all the market participants were adjusting their behavior regarding the imbalance settlement, imbalance volumes increased a lot compared to the first configuration (with “always balance” strategy, i.e. balancing the portfolios no matter the cost). This meant increased the interactions between power companies and the TSO. However, the overall variable cost is lower in the second configuration, which shows that the system is more efficient.

In the TSO’s financial settlement, the factor k only explains one part of the positive revenue of the TSO. It does not seem straightforward to achieve perfect financial equilibrium for the TSO. Compared to the actual imbalance settlement design in France, the reduction of k or moving from average to marginal pricing reduces the net financial result of the TSO.

It also has been found that the weight of the imbalance settlement has more impact on the smallest BRP between Actor 1 and Actor 2.

Compare to the actual imbalance settlement design in France, the reduction of k or moving from average to marginal pricing increase the imbalance cost whereas CREWAP k0.05 decrease the imbalance cost for Actor 1 and Actor 2. For BRPs, adjusting their behavior regarding the imbalance settlement will increase their imbalance costs as they try to optimize their own portfolio (comparing their own internal cost if they are in balance, with the imbalance cost) without looking at the other BRPs.

The aim of this research project was to increase the knowledge of EDF on the imbalance settlement and the balancing market in a liberalized electricity sector. In order to reinforce the results of this report, further research should be done. Indeed, deeper analyses of current simulations and several sensitivity analysis should be done in order to have a more complete view of results.

First of all, different scenarios could be analysed to check if the conclusions are
similar. Actor 2 and 4 could be different. For example, it would be interesting to add the most expensive unit in actor 2 portfolio. Furthermore, units’ parameters could be changed to evaluate their impact. It would also be interesting to add other renewable BRPs to make the model more realistic.

Results would be more robust if the same simulations had been made in a month of summer.

It could be interesting to work on the modelisation of the strategy by adding the spot price or the intraday price to the strategy. Indeed, the strategy can have a large impact on the results.

It would also be interesting to incorporate flows coming from other zones to calculate imbalance volumes.
Bibliography


Chapter 5

Appendix

5.1 Additional information

The following figures are taken from [1].

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

Figure 5.1: Distribution of the capacity between the actors of the studied case in MW
<table>
<thead>
<tr>
<th>Type</th>
<th>Variable cost/€/MWh</th>
<th>Startup cost/k€</th>
<th>Power range/MW</th>
<th>Ramp rate/MW/h</th>
<th>On time/h</th>
<th>Off time/h</th>
<th>Steady period/min</th>
<th>Notice delay/min</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear A</td>
<td>10</td>
<td>325</td>
<td>[250, 1300]</td>
<td>2400</td>
<td>72</td>
<td>24</td>
<td>120</td>
<td>30</td>
</tr>
<tr>
<td>Nuclear B</td>
<td>12</td>
<td>225</td>
<td>[180, 860]</td>
<td>1800</td>
<td>72</td>
<td>24</td>
<td>120</td>
<td>30</td>
</tr>
<tr>
<td>CCGT A</td>
<td>28</td>
<td>21.5</td>
<td>[180, 400]</td>
<td>1020</td>
<td>4</td>
<td>4</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>CCGT B</td>
<td>30</td>
<td>10</td>
<td>[100, 200]</td>
<td>1020</td>
<td>4</td>
<td>4</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>OCGT</td>
<td>150</td>
<td>7.2</td>
<td>[125, 180]</td>
<td>720</td>
<td>0.5</td>
<td>4</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>Coal</td>
<td>20</td>
<td>30</td>
<td>[150, 300]</td>
<td>210</td>
<td>8</td>
<td>8</td>
<td>60</td>
<td>45</td>
</tr>
</tbody>
</table>

Figure 5.2: Parameters of the thermal units

<table>
<thead>
<tr>
<th>Unit</th>
<th>Yearly occurrence/Yearly occurrence</th>
<th>Duration/h</th>
<th>Derating/%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear B</td>
<td>5</td>
<td>7</td>
<td>25</td>
</tr>
<tr>
<td>CCGT A</td>
<td>5</td>
<td>3</td>
<td>50</td>
</tr>
<tr>
<td>CCGT B</td>
<td>5</td>
<td>3</td>
<td>100</td>
</tr>
<tr>
<td>Coal</td>
<td>7.5</td>
<td>7</td>
<td>50</td>
</tr>
</tbody>
</table>

Figure 5.3: Outage parameters of the thermal units
<table>
<thead>
<tr>
<th>Unit</th>
<th>Power company</th>
<th>Number of outages</th>
<th>Out of service capacity (MW)</th>
<th>Date of outages (MM/DD hh:mm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear B unit 1</td>
<td>A</td>
<td>4</td>
<td>225</td>
<td>01/07 17:00, 01/08 07:45, 01/12 02:00, 01/17 04:00</td>
</tr>
<tr>
<td>Nuclear B unit 2</td>
<td>A</td>
<td>6</td>
<td>225</td>
<td>01/05 11:15, 01/09 07:15, 01/17 12:00, 01/21 06:45, 02/01 05:00, 02/03 11:15</td>
</tr>
<tr>
<td>CCGT A unit 1</td>
<td>B</td>
<td>6</td>
<td>200</td>
<td>01/07 07:00, 01/09 16:15, 01/10 09:45, 01/13 12:30, 01/23 07:15, 01/28 12:15</td>
</tr>
<tr>
<td>CCGT B unit 1</td>
<td>A</td>
<td>14</td>
<td>200</td>
<td>01/03 23:00, 01/04 04:00, 01/04 17:45, 01/05 20:00, 01/07 10:15, 01/12 20:45, 01/18 21:45, 01/19 08:15, 01/19 18:00, 01/23 03:00, 01/23 13:45, 01/26 13:00, 01/31 10:45, 02/01 22:30</td>
</tr>
<tr>
<td>CCGT B unit 2</td>
<td>B</td>
<td>7</td>
<td>200</td>
<td>01/04 13:00, 01/06 12:45, 01/10 06:15, 01/11 09:15, 01/18 14:00, 01/19 14:15, 01/20 17:45</td>
</tr>
<tr>
<td>Coal</td>
<td>B</td>
<td>4</td>
<td>150</td>
<td>01/06 21:00, 01/19 21:30, 01/20 07:45, 01/31 21:15</td>
</tr>
</tbody>
</table>

Figure 5.4: Details on outages
5.2 Unit models in SiSTEM[1]

In the units-scheduling problem (2.2) of Section 2.4, each production unit \( i \) has its own set of technical constraints \( X_i \) and a cost function \( C_i(p_i) \). Technical constraints limit the output power \( p_i \) and the upward and downward balancing capacity, \( b_i^+ \) and \( b_i^- \). In the model, four types of production unit are implemented: basic units, thermal units, hydro-electric reservoirs and curtailable production. They respectively are the topics of Sections 5.2.1, 5.2.2, 5.2.3 and 5.2.4. 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. The extension to other models is not implemented but could easily be done using the helps offered abstract class \texttt{ControllableUnit}.

5.2.1 Basic units

The model of a basic unit \( i \) is given by (5.1) is a linear model of a production unit without binary variables.

### Sets
\[ \mathcal{M}_i \quad \text{Notice period} \]

### Parameters
\[ \beta_i \quad \text{Marginal cost} \]
\[ [d_i, u_i] \quad \text{Minimum and maximum ramping rate} \]
\[ r_{i,t}, r_{i,t}^- \quad \text{Upward and downward reserve of a unit} \]
\[ [p_i^{\min}, p_i^{\max}] \quad \text{Production range} \]
\[ r_{i,t}^+, r_{i,t}^- \quad \text{Upward and downward reserve of a unit} \]

### Variables
\[ b_{i,t}^+, b_{i,t}^- \quad \text{Upward and downward balancing capacity of a unit} \]
\[ p_{i,t} \quad \text{Power output} \]

### Optimization problem
\[
C_i(p_i) = \sum_{t \in T} \beta_i(p_{i,t} + b_{i,t}^+ + b_{i,t}^-) \quad \forall i \in \mathcal{U}^h 
\]

with \( X^h = \{ \)
\[
\begin{align*}
  b_{i,t}^- + r_{i,t}^- & \geq p_{i,t}^{\min} - p_{i,t} \\
  b_{i,t}^+ + r_{i,t}^+ & \leq p_{i,t}^{\max} - p_{i,t} \\
  p_{i,t} - p_{i,t-1} + b_{i,t}^+ + r_{i,t}^+ & \leq u_i \\
  p_{i,t} - p_{i,t-1} + b_{i,t}^- + r_{i,t}^- & \geq d_i \\
  p_{j,t} = p_{j,t}^0 
\end{align*}
\]

where \( p_{i,t} \in [p_i^{\min}, p_i^{\max}], b_{i,t}^+ \in \mathbb{R}^+, b_{i,t}^- \in \mathbb{R}^- \forall t \in T \} \).
The flexibility of a basic unit is given by the difference between the initial schedule and the alternative schedule. The flexibility in each time step is offered independently as a simple single time step offer which can be partially accepted. Figure 5.5 gives an example for upward flexibility.

5.2.2 Thermal units model

The constraints considered for the thermal units are summarized in the example of production plan given in Figure 5.6. These constraints are:

1. a minimum notice delay before changing the production plan (in time steps rounded to the closest integer.),

2. the start-up and shutdown ramping rates when the unit is below the minimum power,

3. upward and downward ramping rates in production phase,

4. a minimum steady-state time in the production phase,

5. a minimum off-time after a shutdown and

6. outages.

Model (5.2) 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 (5.4). Note that formulation (5.2) may differ slightly from the literature in order to obtain a valid schedule on sub-hourly resolutions.

Parameters
Figure 5.6: Example of production plan of a thermal unit. To each number corresponds constraints of the unit.

\[ \beta_i \] Variable cost
\[ d_i^s \] Shutdown ramping rate \( \in \mathbb{R}^- \)
\[ [d_i, u_i] \] Minimum and maximum ramping rate in production phase (\( d_i < 0, u_i > 0 \))
\[ u^{on}, u^{off} \] Minimum up and down time steps
\( \mathcal{M}_i \) Set of notice period
\[ \gamma_i \] Start-up cost
\[ [p_{i,t}^{min}, p_{i,t}^{max}] \] 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 \( p_i = \{p_{i,t}, \forall t \in \mathcal{T}\} \).

**Constraints**

\[ C_i(p_i) = \sum_{t \in \mathcal{T}} (\beta_i p_{i,t} + \gamma_i v_{i,t}) \] (5.2a)

with \( X_i = \{ \)

\[ x_{i,t} + y_{i,t} + z_{i,t} \leq 1 \quad \forall t \in \mathcal{T} \] (5.2b)

\[ x_{i,t} \leq 1 - y_{i,t-1} - z_{i,t-1} \quad \forall t \in \mathcal{T} \] (5.2c)
where $w_{i,t}, x_{i,t}, y_{i,t}, z_{i,t} \in \{0, 1\}, \forall t \in T$. Constraints (5.2b)-(5.2h) link the startup, production and shutdown phase binary variables. The unit may only be in one of the modes at most (5.2b). A unit cannot be started if it is in production or shutdown phase in the previous time step (5.2c). Note that even if the minimum down time steps is set to zero, this constraint enforces at least one time step between a shut-down phase and the next start-up phase. The production phase can only be
reached from a start-up phase or a production phase (5.2d). From a start-up phase, the unit must go to another start-up phase or in-production phase (5.2e). A unit can be in shutdown phase if its status in the previous time step is either production or shutdown (5.2f). Equality (5.2g) 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. The formulation is further tightened by inequality (5.2h) expressing that a unit cannot start and stop simultaneously.

Based on the three statuses of the unit: start-up, production or shutdown, the dynamic constraints of the unit are given by (5.2i)-(5.2r). The maximum production of the unit is constrained by (5.2i). If the unit is producing, its minimum power is defined by (5.2j). In the shutdown phase, the production can only be zero in the last shutdown time step (5.2k). The schedule of the unit is fixed on time steps no further than the notice delay (5.2l). Ramping constraints are handled by (5.2m)-(5.2n). The rampings in the start-up and shutdown phases are forced to equal the value given as a parameter by constraints (5.2o)-(5.2p). 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 (5.2q). A unit which is off must stay off for at least a minimum amount of time steps (5.2r).

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.

**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**

\[
\begin{align*}
    b^+_{i,t} + r^+_{i,t} & \leq p^\text{max}_{i,t} - p_{i,t} & \forall t \in T \\
    b^-_{i,t} + r^-_{i,t} & \geq y_t(p^\text{min}_{i,t} - p_{i,t}) & \forall t \in T \\
    b^+_{i,t} + r^+_{i,t} & \leq y_t(p^\text{max}_{i,t} - p^\text{min}_{i,t}) & \forall t \in T \\
    b^-_{i,t} + r^-_{i,t} & \geq y_t(p^\text{min}_{i,t} - p^\text{max}_{i,t}) & \forall t \in T \\
    b^+_{i,t} + r^+_{i,t} + p_{i,t} - p_{i,t-1} & \leq u_i & \forall t \in T \\
    b^-_{i,t} + r^-_{i,t} + p_{i,t} - p_{i,t-1} & \geq d_i & \forall t \in T 
\end{align*}
\]

The reserve that must be provided by the unit is enforced by (5.3a)-(5.3f). These constraints also compute the available amount of balancing capacity from the unit. Equations (5.3a)-(5.3b) ensure that the necessary power margin is kept. Balancing
and reserve cannot be provided if the unit is not on, following constraints \(5.3c\)-(5.3d). Inequalities \(5.3e\) - \(5.3f\) 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. 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 Cycling affects the lifespan of heat recovery steam generators, which are part of combined cycle plants 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

In this model, minimum steady-state periods are imposed by extending the optimization model \(5.2\) with the constraints given in \(5.4\).

**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**

\[y^a_{i,t} + y^b_{i,t} + y^c_{i,t} = y_{i,t}\quad \forall t \in \mathcal{T}\]  
(5.4a)

\[y^a_{i,t} + y^b_{i,t} \geq y^a_{i,t-1}\quad \forall t \in \mathcal{T}\]  
(5.4b)

\[y^b_{i,t} + y^c_{i,t} + z_{i,t} \geq y^c_{i,t-1}\quad \forall t \in \mathcal{T}\]  
(5.4c)

\[y^a_{i,t} \leq 1 - (y^c_{i,t-1} + z_{i,t-1})\quad \forall t \in \mathcal{T}\]  
(5.4d)

\[y^c_{i,t} \leq 1 - (y^a_{i,t-1} + x_{i,t-1})\quad \forall t \in \mathcal{T}\]  
(5.4e)

\[x_{t-1} \leq x_{i,t} + y^a_{i,t} + y^b_{i,t}\quad \forall t \in \mathcal{T}\]  
(5.4f)

\[y^a_{i} \leq x_{t-1} + y^a_{i-1} + y^b_{i-1}\quad \forall t \in \mathcal{T}\]  
(5.4g)

\[y^c_{i} \leq y^b_{i-1} + y^c_{i-1}\quad \forall t \in \mathcal{T}\]  
(5.4h)

\[d_i(1 - y^b_{i,t}) \leq p_{i,t} - p_{i,t-1} \leq u_i(1 - y^b_{i,t})\quad \forall t \in \mathcal{T}\]  
(5.4i)

\[d_i(1 - y^a_{i,t}) \leq p_{i,t} - p_{i,t-1} \leq u_i(1 - y^a_{i,t})\quad \forall t \in \mathcal{T}\]  
(5.4j)
\( p_{i,t} - p_{i,t-1} \geq u_i(y_{a,i,t}^t + y_{a,i,t-1} + x_{i,t-1} - 1) + d_i(y_{c,i,t}^t + z_{i,t}) \quad \forall t \in \mathcal{T} \quad (5.4k) \)
\( p_{i,t} - p_{i,t-1} \leq u_i(x_{i,t} + y_{a,i,t}^t) + d_i^c(y_{c,i,t}^t + y_{c,i,t-1} - 1) \quad \forall t \in \mathcal{T} \quad (5.4l) \)
\( p_{i,t} - p_{i,t-1} \leq u_i(x_{i,t} + y_{a,i,t}^t) + d_i^c(z_{i,t} + y_{c,i,t-1} - 1) \quad \forall t \in \mathcal{T} \quad (5.4m) \)
\( p_{i,t} - p_{i,t-1} \leq u_i(x_{i,t} + y_{a,i,t}^t) + d_i^c(y_{c,i,t}^t + y_{c,i,t+1}^t + z_{i,t+1} - 1) \quad \forall t \in \mathcal{T} \quad (5.4n) \)
\( n^b(y_{b,i,t}^b - y_{b,i,t-1}^b) \leq \sum_{\tau=t}^{t+n^b-1} y_{b,i,t}^b \quad \forall t \in \mathcal{T} \quad (5.4o) \)

with \( y_{a,i,t}^t, y_{b,i,t}^b, y_{c,i,t}^t \in \{0, 1\}, \forall t \in \mathcal{T} \). Constraints (5.4a)-(5.4e) defines the variables of the production phase status. They are tightened by inequalities (5.4f)-(5.4h). Ramping constraints in the production phase are enforced by (5.4i)-(5.4j). Additional ramping constraints (5.4k)-(5.4n) 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 (5.4o).

To simplify the description, models (5.2)-(5.4) 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. Figure 5.7 pictures the problem of additional minimum off time constraints to enforce due to a future planned start. 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 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.

Figure 5.7: Minimum off time constraint outside of the optimization horizon to enforce in order to ensure a consistent schedule.

Upward unit-based flexibility is obtained by solving the optimization problem 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 5.8a. Upward offers are separated into two parts: base block bids and operation bids. Figure 5.8a 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 5.8b. 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 5.8b, 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 5.8a, 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.

5.2.3 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 $U^h$ is scheduled at once using model (5.5) incorporating a coupling constraint between the different reservoirs in the global portfolio model $X^h$. 
Figure 5.8: Building of flexibility offers of a thermal unit.

Sets

- $U^h$  Hydro-electric reservoirs of the portfolio
- $M_j$  Notice period

Parameters

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

Variables
\[
p_{j,t} \quad \text{Power output}
\]
\[
b_{j,t}^+, b_{j,t}^- \quad \text{Upward and downward balancing capacity of a unit}
\]
\[
s_{j,t} \quad \text{Stock level}
\]
\[
[D_{i,t}^{\min}, D_{i,t}^{\max}] \quad \text{Global stock bounds slacks}
\]
\[
[d_{j,t}^{\min}, d_{j,t}^{\max}] \quad \text{Stock bounds slacks}
\]

Constraints

\[
C_1(p_i) = \sum_{j \in U^h} \left( -\beta_j (s_{j,T} - s_{j,0}) + \sum_{t \in T} \left( \beta_j^m m_{j,t}^{\min} - \beta_j^m m_{j,t}^{\max} \right) \right) + \sum_{t \in T} \left( \beta_t^m M_{i,t}^{\min} - \beta_t^m M_{i,t}^{\max} \right)
\]

with \(\mathcal{X}^h = \{\)

\[
s_{j,t} = s_{j,t-1} + a_{j,t} \Delta t - n_j p_{j,t} \Delta t \quad \forall (j, t) \in U^h \times T \quad (5.5a)
\]
\[
p_{j,t} + b_{j,t}^+ + r_{j,t}^+ \leq p_{j,t}^{\max} \quad \forall (j, t) \in U^h \times T \quad (5.5b)
\]
\[
p_{j,t} + b_{j,t}^- + r_{j,t}^- \geq p_{j,t}^{\min} \quad \forall (j, t) \in U^h \times T \quad (5.5c)
\]
\[
s_{j,t} - n_j \Delta t \sum_{\tau = 0}^t \left( b_{j,\tau}^+ + r_{j,\tau}^+ \right) \geq s_{j,t}^{\min} + d_{j,t}^{\min} \quad \forall (j, t) \in U^h \times T \quad (5.5d)
\]
\[
s_{j,t} - n_j \Delta t \sum_{\tau = 0}^t \left( b_{j,\tau}^- + r_{j,\tau}^- \right) \leq s_{j,t}^{\max} + d_{j,t}^{\max} \quad \forall (j, t) \in U^h \times T \quad (5.5e)
\]
\[
\sum_{j \in U^h} \left( s_{j,t} - n_j \Delta t \sum_{\tau = 0}^t \left( b_{j,\tau}^+ + r_{j,\tau}^+ \right) \right) \geq S_t^{\min} + D_{j,t}^{\min} \quad \forall t \in T \quad (5.5f)
\]
\[
\sum_{j \in U^h} \left( s_{j,t} - n_j \Delta t \sum_{\tau = 0}^t \left( b_{j,\tau}^- + r_{j,\tau}^- \right) \right) \Delta t \leq S_t^{\max} + D_{j,t}^{\max} \quad \forall t \in T \quad (5.5g)
\]
\[
p_{j,t} = p_{j,t}^0 \quad \forall (j, t) \in U^h \times M_j \quad (5.5h)
\]

where \(s_{j,t} \in [s_{j,t}^{\min}, s_{j,t}^{\max}]\), \(p_{j,t} \in [p_{j,t}^{\min}, p_{j,t}^{\max}]\) \(\forall (j, t) \in U^h \times T\), \((d_{j,t}^{\min}, d_{j,t}^{\max}) \in \mathbb{R}^- \times \mathbb{R}^+ \forall (j, t) \in U^h \times T\), \((D_{j,t}^{\min}, D_{j,t}^{\max}) \in \mathbb{R}^- \times \mathbb{R}^+ \forall t \in T\). The cost of spilling water expressed in (5.5a) 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 (5.5a). Power bounds, integrating the flexibility, are given by inequalities (5.5b)-(5.5c). The effect of the worst-case use of flexibility on the stock is defined by (5.5d)-(5.5e). Stock bounds are implemented as soft constraints. The cost function (5.5a) 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 (5.5f)-(5.5g), including the available flexibility. Finally, constraint (5.5h) fixes the schedule of a reservoir in time steps in which it cannot be modified.

Note that in model (5.5), 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.

5.2.4 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 (5.6) and relies on a forecast of the available production of the unit. The details of the forecast mechanism are given in Section 2.1.3.

**Parameters**

- $\beta_i$: Variable cost
- $p_{i,t}^{max}$: 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**

$$C_i(p_i) = \sum_{t \in T} \beta_i p_{i,t}$$

(5.6a)

with $X^h = \{ -b_{i,t}^- \leq p_{i,t} \leq p_{i,t}^{max} - b_{i,t}^+ \quad \forall t \in T \}$.

(5.6b)

where $p_{i,t} \in [0, p_{i,t}^{max}] \forall t \in T$. In this model, curtailable production is not allowed to provide reserves but may be used as a means of balancing.

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.