Quantitative assessment of electricity market designs : illustrations of short-term and long-term dynamics

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Abstract

Following power market reforms, market design, i.e. the study of new markets to replace efficiently the previous monopoly, becomes central in the economic literature. However, due to several technical characteristics of electricity, this task is complex. A third party is then required to help design these markets in an efficient way and to set the rules under which private decentralized market players interact. This complexity explains why market design remains a work in progress. This thesis contributes to the current discussions by giving insights on the most efficient market designs to implement to ensure the reliability of power systems.

A first focus is made on the short-term dimension of reliability, i.e. the security of power systems. To maintain a balanced system, the system operator has to ensure the availability of a sufficient level of reserves in real time: this is the aim of the security model. In this thesis, a quantitative assessment of the economic impacts that a transition to a different security model would have for the French power system is carried out. An agent-based modelling is developed to simulate the decisions of profit-maximizing players on several short-term markets. Simulations show that the current French security model results in lower costs than the alternative one implemented in several European countries, and should therefore be maintained for the French power system.

A second focus is made on the long-term dimension of reliability, i.e. the adequacy. The economic performances of a capacity market and a strategic reserve mechanism, two mechanisms designed to solve the adequacy issue, are compared. In order to capture the cyclical nature of investments, these mechanisms are studied from a dynamic point of view. To this end, a long-term model is developed based on a System Dynamics approach. It simulates the investment and shutdown decisions made by market players considering their imperfect behaviours. Main results show that the capacity market solves the adequacy issue at a lower cost than the strategic reserve mechanism.

Keywords:
Electricity market design; Capacity adequacy; Short-term security; Simulation modelling

Résumé

Suite aux réformes des marchés électriques, la question du market design, c'est-à-dire l'étude des nouveaux marchés destinés à remplacer l'ancien monopole, est devenue centrale dans la littérature économique. Toutefois, les caractéristiques techniques de l'électricité rendent cette tâche complexe et l'intervention des pouvoirs publics est souvent nécessaire pour établir les règles du jeu efficaces que les acteurs de marché devront suivre. Cela explique pourquoi le market design demeure un sujet d'actualité. Cette thèse contribue aux discussions actuelles en étudiant plusieurs architectures de marché à mettre en place afin d'assurer la fiabilité du système électrique de la façon la plus efficace.

La fiabilité est d'abord étudiée sous sa dimension de court terme, appelée sûreté. Pour garantir un équilibre en temps réel, l'opérateur du système doit s'assurer de disposer d'un niveau suffisant de réserves: c'est l'objectif du modèle de sûreté. Dans cette thèse, les impacts économiques induits par un changement de modèle de sureté pour le système électrique français sont évalués. Une modélisation de type Agent-Based est développée pour simuler les décisions des acteurs sur plusieurs marchés de court terme. Les résultats montrent que le modèle de sureté français actuel conduit à des coûts inférieurs à ceux du modèle alternatif mis en œuvre dans d'autres pays européens. Le maintien du modèle actuel en France apparait donc justifié.

La dimension long terme de la fiabilité, à savoir l'adéquation, est ensuite étudiée. Les performances économiques d'un marché de capacité et d'un mécanisme de réserve stratégique, deux solutions conçues pour résoudre le problème d'adéquation, sont comparées. Afin de considérer la nature cyclique des investissements, ces mécanismes sont étudiés d'un point de vue dynamique par l'intermédiaire d'une modélisation de type System Dynamics. Celle-ci simule les décisions d'investissements et de fermetures prises par les acteurs de marché, en considérant leurs comportements imparfaits. Les principaux résultats montrent que le marché de capacité résout la question de l'adéquation à un coût moindre.

Mots-clés:
Architecture des marchés électriques ; Adéquation de capacité ; Sûreté du système électrique ; Simulation

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General introduction

Power reforms have radically change the way the electric system works: from a vertically integrated entity, without any competition, any market based mechanism and with a unique player, the new structure introduces competition in the generation and retail activities, multiple market players and decentralized decisions based on market outcomes. The way the electricity system is managed should then evolve, from the classical and previous control-and-command management performed by the integrated utility to market-oriented solutions. Reforms in the power industry then require the design of new markets which replace the previous control-and-command management and lead, ideally, to more efficient decisions making while ensuring the reliability of the power network. The new organization of the competitive segments (in particular for generation), the creation of new rules to ensure coordination and to reach an efficient functioning of the energy system as a whole is called the market design in literature. As Stoft describes it, "the problem of market design is not to invent clever new prices but to design a market that will reliably discover the same prices economics has been suggesting since Adam Smith" (Stoft, 2002), i.e. prices that will induce short-term and long-term efficiency.

However, electricity is a very particular and complex good and the change of paradigm, from control-and-command management to markets, is all but easy. Several market failures due to the technical characteristics of electricity, for instance, the presence of externalities for the network due to loop flows (Pignon, 2003), the risk of market power abuse due to time and location differentiation of electricity (Smeers, 2005) or the presence of public good such as reserves (Oren, 2005), make the design of efficient markets difficult (Joskow, 2005). As a consequence, new and efficient markets cannot create themselves to consider properly all the characteristics of electricity and a third party needs to intervene to introduce the new rules (Hogan, 2002; Staropoli, 2001). Moreover, markets cannot substitute to all previous control-and-command management because of the complex technical characteristics of electricity and the limits of current technologies (Boucher and Smeers, 2002; Wilson, 2002). Indeed, current information systems do not enable to trade electricity quickly enough in real time to ensure a constant balance between generation and consumption. Then, a centralized and non-market based entity, the system operator is needed and is responsible of the real-time market. This activity is performed either by the transmission owner (as it is the case in Europe and for which the term TSO for Transmission System Operator is used) or by an independent entity (as it is the case in the USA, referred as ISO for Independent System Operator). Since its actions are highly linked with the decisions of decentralized players and then the outcomes of markets, the design of its tasks should also be studied with caution to reach efficient outcomes. The success of market reform thus should encompass at least two fields of research:

- When it is technically possible, the replacement of control-and-command management by markets and the study of the efficient design of these markets
- When markets cannot substitute the previous control-and-command management, the study of efficient design of these non-market-based methods and the interaction between the system operator and the market.

The liberalization stage of the power system should then not be understood as the end of regulation on the competitive markets but as a lower and differently oriented regulation (Pollitt, 2007). A third party still oversees the industry. However, it does not control the results (for example, the price of the electricity or the investments) but only the screenplay (i.e. the different rules, the relationship between market players, in particular between private players and the natural monopolies) and it lets market players act to provide the pursued efficient results (Sioshansi, 2006). For policy makers, the task of market liberalization and the creation of a new power organization is complex. If market designs have flaws and if transformation is implemented incorrectly or incompletely, this could lead to inefficient results and costly performances (Joskow, 2008). In the worst scenario, the result of power market reforms can be worse than when no competition was introduced (Woo et al., 2003).

Market design has then been a central topic of research in energy economics literature to prevent such inefficiencies and ensure the success of market reforms. The study of market design began as soon as the first market reforms, i.e. more than 30 years ago. However, market design is still a current central topic in literature nowadays. Three mains reasons can be mentioned for this more than 30–year ongoing process. First, at the beginning of the power reforms, ground debates for market design took place around the wholesale and retail markets and their design, which were a prerequisite to ensure the success of market reforms (Concettini and Créti, 2013; Hogan, 1998; Joskow, 2005). Progressively, market designs extend to other considerations such as the balancing mechanism, maybe less essential at first sight at the beginning of the market reforms but still source of possible efficiency improvement. Second, market design evolves along the institutional environment and in particular the new objectives of energy policy to promote green technologies to produce electricity. For instance, the massive support for renewable technologies for few years leads to significant impacts on the outcomes of the markets (e.g. increasing imbalances and need for reserves, increasing uncertainty of market revenues for investors, need of back up capacity). Several evolutions of market designs are then discussed and proposed to integrate these intermittent technologies at a least cost (Hiroux and Saguan, 2010; Vandezande et al., 2010). Finally, market design also evolves to correct the possible flaws of previous market choices that were not identified at the beginning (Keay, 2016). These flaws only become apparent after some time, often caused by external events. This is what Hogan called the reform of the reforms (Hogan, 2002). California or the UK are two examples of countries where market design was adapted and improved following observation of inefficient results, in particular due to market power (Mansour, 2006; Newbery, 2005).

Market design then remains a work in progress and a learning process, which explains why it is still debated and a central research subject in economics while reforms began 30 years ago. In this context, modelling has become a major field of research in power economics to support the choice of market design. Indeed, it is impossible to implement a market design for real and to measure its outcomes ex post: the consequences of a wrong design can be dramatic (high prices, risks of blackouts). Ex ante modelling should then be performed before implementing a market design to detect any inefficiency. Moreover, a qualitative ex-ante evaluation of market design without modelling or based on insights from other subjects of economics can be difficult to perform due to the particularities of the electricity as a good and the complexity of the electricity chain.

Whereas modelling already existed when power system was organized with a vertically integrated utility, its conception largely changes with the reforms. Indeed, previous modelling for the regulated utility aimed mainly at minimizing the total costs of generation while serving the demand and respecting the different technical constraints.

These modellings were cost-based, centralized and did not consider any prices in the decisions process. The power market reforms changed this paradigm: modelling has to be updated to consider the introduction of competition and the behaviour of profit-based and decentralized market players (Weigt, 2009).

Among the different modelling approaches, three main ones are mentioned and used in literature: the optimization approach, the equilibrium approach and the simulation approach (Ventosa et al., 2005). Optimization models generally aim at maximizing a single's firm profit or at maximizing the social welfare: it represents the behaviour of a benevolent monopoly but may also be used to consider the decisions of decentralized market players under perfect competition and perfect information. To study imperfect competition and strategic behaviours, equilibrium models can be used: they are based on the profit maximization of several rival market players and the computation of the resulting market equilibrium. Several common models such as the Bertrand or Cournot competition can be used to consider imperfect competition. Finally, when the problem becomes too complex to study (in particular including non-convex constraints) and/or should integrate the dynamic dimension of the power system functioning, a simulation approach is considered. It aims at representing more precisely the behaviour of market players and the evolution of their strategy based on past outcomes. In particular, this approach studies whether an equilibrium can be reached. Moreover, it provides a flexible setting for market modelling when formal equilibrium approaches are no longer feasible.

This thesis aims at contributing to the current debates on market design in electricity systems by giving some insights on which solution to implement resorting to modelling. In particular, a focus is made on components of market design targeting the provision of reliability, i.e. the delivery of electricity to consumers within accepted standards and in the amount desired. Reliability generally encompasses two dimensions: a short-term one, called security, and a long-term dimension, called adequacy (Pérez-Arriaga, 2007). The security issue focuses on the ability of power systems to balance demand and supply in real time and to react efficiently to unexpected disturbances. On the contrary, adequacy studies several years before the real time the existence of enough installed (or expected to be installed) capacities to meet efficiently the expected demand of electricity. In this thesis, a focus is made both on the security issue and on the adequacy one. These two dimensions are essential to maintain a well-functioning power system and then ensure the success of market reforms. Moreover, as explained in the following sections, they are at the centre of current discussions about European market designs due to reasons previously mentioned about the on-going study of market design. Indeed, solutions implemented at the beginning of the market reforms are challenged and may have to evolve to gain efficiency. This is particularly the case for designs supervising the security, which were often conceived on low economic ground and more seen as a technical security mechanism to avoid major blackouts. Regarding the adequacy, current discussions focuses on likely flaws of energy markets which may not enable to reach an optimal level of installed capacity. Besides, these current discussions on the evolution of market design are exacerbated by the massive development of renewable technologies which deeply modifies both the short-term dynamics (by increasing imbalances and jeopardizing the security) and the long-term dynamics (by increasing the risk investments and the need of back up capacity). The two research questions are described in the following paragraphs.

Focus on a short-term issue: the efficient design of the security models

A continuous balance in real time between generation and load is essential to ensure the security of the power system (i.e. to avoid major blackouts). Given the current limitations of IT technologies, this task cannot be left to decentralized market players: the responsibility of a balanced power system is then regulated and overseen by a third party, the system operator (called the Transmission System Operator, TSO, in Europe) thanks to a dedicated mechanism (Boucher and Smeers, 2002; Wilson, 2002). In particular, the TSO ensures the security of the power system by activating reserves, i.e. capacity which can quickly modify their production or consumption.

However, the TSO does not own these reserves: they are provided by market players from the generation or the consumption sides. Moreover, the reserves are a public good (Oren, 2005): private market players then tend to undersupply them and the TSO may be unable to activate enough reserves to ensure the balance. That is why additional mechanisms were created following the power market reforms in order to ensure that a sufficient level of reserves is available in real time despite the characteristics of public good: these solutions are called security models. A classic solution implemented in European power systems is to procure the reserves in advance of real time through a new market called the reserves procurement market. The forward procurement of reserves through financial commitment incentivizes private market players to provide reserves and then ensures the TSO to have a minimum level of reserves in real time to deal with imbalances. On the contrary, the French TSO has implemented a slightly different solution: it relies on forward procurement of reserves but can also ensure the availability of reserves by modifying directly the generation output of some power plants between the day-ahead market clearing and real time.

At the beginning of the market reforms, markets and mechanisms implemented to ensure the security of the power systems were seen more as a technical security mechanism to avoid major blackouts rather than a centrepiece in the competitive markets (Glachant and Saguan, 2007). The study of efficient market designs to ensure the security of power systems was then limited, particularly in Europe. Solutions based on weak economic justifications could have then been preferred to consider technical peculiarities of electricity and avoid imbalances and blackouts. The economic consequences of these rules are a recent subject of research. Market design should then evolve to improve the efficiency of these mechanisms while still ensuring the security of the power systems. In this context, the need for an economic comparison of security models is growing. In particular, the specific solution implemented in France should be studied and compared with other security models implemented in Europe to assess whether policy makers should modify the current French design to gain efficiency. It will be the first research question of this thesis.

To answer this research question, a modelling based on a simulation approach is developed. It simulates the decisions of decentralized and profit-seeking players on several short-term markets, from reserves procurement to the balancing mechanism. This type of approach enables to model the complex short-term sequence of markets and mechanisms while considering technical constraints of power plants, the bidding strategy of market players and their likely imbalances due to forecast errors, which appear essential to study the French security model. Other modelling approaches do not seem suitable to consider easily and thoroughly these characteristics.

Focus on a long-term issue: the efficient design of the capacity remuneration mechanisms

Another major discussion in the current literature lies in the question of investments in generation capacities and the ability of current power markets to induce efficient investments. Power market reforms in recent decades and the introduction of competition within the generation activity have deeply changed the way investment decisions in generation assets are made (Dyner and Larsen, 2001). Even if in theory a competitive short-term market can induce optimal investments decisions (Caramanis, 1982; Rodilla and Batlle, 2012), several market failures are observed in current power markets and may impede a long-term optimal investment equilibrium (Cramton and Stoft, 2006): the traditional energy market may result in under capacity and costly associated blackouts. Policy makers are then improving the previous market designs by correcting these flaws. In particular, new mechanisms, called capacity remuneration mechanisms (CRM), are implemented to solve the adequacy issue (Batlle and Rodilla, 2010). The capacity market and the strategic reserve mechanism are two main examples currently considered in Europe. The performances of these new mechanisms have to be investigated so that policy makers can know which is the most efficient. In particular, CRMs should solve the adequacy issue at a limited cost for the consumers.

Besides, ensuring the adequacy of power systems is not only about investing in the right amount of capacity: it is also about doing it at the right time (Roques, 2008). Indeed, the risk of cyclical tendencies in generation investments, known as boom and bust cycles, has been highlighted in the literature (Arango and Larsen, 2011; Green, 2006). This risk is explained by several characteristics of investors, such as their imperfect foresight or their herd behaviour. Consequently, the dynamic aspects of generation investments also matter when studying the adequacy issue. The design of CRMs should then consider the risk of cyclical behaviour when they are investigated and implemented by policy makers.

The second research question of this thesis will study this point and compare the economic performances from a dynamic point of view of two types of capacity remuneration mechanisms, the capacity market and the strategic reserve mechanism. Moreover, this comparison should be based not only on their adequacy effectiveness (i.e. reaching an optimal level of installed capacity) but also on their cost effectiveness (i.e. doing so at least costs).

To answer the research question, a long-term modelling based on a simulation approach is developed. This choice enables to compare CRMs dynamically considering that a long-term equilibrium may not be reached, which is not possible using an optimisation or equilibrium approach. The developed modelling simulates the investment and shutdown decisions of market players while considering their real and imperfect characteristics such as the herd behaviour.

Organisation of the dissertation

This dissertation is divided into two parts, each one answering one of the research questions.

The first part focuses on the short-term issue of the design of the security models and the economic comparisons of two types of security models for the French power system. It carries out a quantitative assessment of the economic impact that a transition to a reserves approach would have for the French power system. An agent-based modelling approach is developed, which simulates the decisions of decentralized and profit-seeking market players on several short-term markets, from reserves procurement to the balancing mechanism (both managed by the TSO) through the day-ahead and intraday markets.

This part is itself divided in four chapters. The first chapter introduces the concept of reserves and of security models. In particular, the characteristics of the French one are presented. The research question, and how it fits into literature, are also described in this chapter. In chapter 2, the modelling used to study security models is developed. Input parameters of simulations, close to the French power system, are described in chapter 3. Finally, results and comparison between both security models are presented in chapter 4.

In the second part of the thesis, the long-term issue of investment in electricity generation is investigated. In particular, two designs of capacity remuneration mechanism are studied from a dynamic point of view and compared with regard to adequacy effectiveness (their ability to reduce shortages) and cost effectiveness (the costs to build and operate power plants to reduce shortages) criteria. A long-term model is developed based on a System Dynamics approach. It aims at simulating the investment and shutdown decisions made by market players in a liberalized market regime considering their imperfect behaviours.

This part is itself divided in three chapters. The chapter 5 presents the context of investment decisions in current energy markets and the need to introduce capacity remuneration mechanisms. In particular, the dynamic aspect of investment decisions and their likely cyclical tendencies are presented. The research question and the current missing points in the literature are also introduced in this chapter. In chapter 6, the modelling used to study the two types of CRMs (the capacity market and the strategic reserve mechanism) is developed. Finally, the input parameters of the simulations, the results and the economic comparison between both CRMs are presented in chapter 7.

A general conclusion is finally drawn at the end of the dissertation. Future relevant works to broaden the findings of this thesis are also described.

Part I. Market design of a short-term issue: the economic comparisons of two types of security models for the French power system

Security of power systems, i.e. their ability to deal with unexpected imbalances in real time, is essential to ensure the stability of the frequency and then the stability of the power system as a whole. Without this security, large unsolved imbalances can result in a cascading failure and consequently in major rolling blackouts and their tremendous associated costs for the society. To avoid this situation and balance the system, all Transmission System Operators (TSO) rely on some capacities which are available in real time to be activated upward or downward: these capacities are called reserves. The presence of these reserves in real time in a sufficient level is essential for the security of power systems. Several solutions exist in current US and European power systems to guarantee this. They are called security models in the following chapters. In particular, the French security model, referred to as the “margin approach” in this thesis, exhibits specific characteristics compared to the solution implemented in Germany or in the Netherlands, called the “reserves approach” in this part. In a context where harmonization of national market designs is at the centre of European discussions and where various academic studies and policy makers’ decisions focus on the efficiency of real-time markets, the need for an economic comparison of both aforementioned security models is growing. This part of the thesis studies this question and quantifies what would be the costs or benefits for the French power system to change its security model and implement a reserves approach[1].

This part is structured as follows. The first chapter introduces the concept of reserves and of security models. In particular, the characteristics of the French one are presented. The research question, and how it fits into the current literature, are also described in this chapter. In the chapter 2, the modelling used to study two security models, namely the margin and the reserves approaches, is developed. Input parameters of simulations, close to the French power system, are described in chapter 3. Finally, results and comparison between both security models are presented in chapter 4.

[1] This research question and results presented in this part are derived from a study realized by the author for the French TSO. Input parameters and several assumptions about the modelling of the French power system result from discussions with the French TSO. The author would like to sincerely thank the RTE interlocutors for their interesting and fruitful insights. Full responsibility for any errors and omissions lies with the author and the opinions expressed in these chapters are his own.

Chapter 1. Security models in European power systems and presentation of the research question

<u>*Résumé du chapitre 1 en français*</u> :

Afin de se prémunir contre un possible déséquilibre entre l'offre et la demande d'électricité en temps réel, il est nécessaire d'avoir recours à des activations de réserves, i.e. de capacités disponibles pour modifier le niveau de production ou de consommation à la hausse ou à la baisse suffisamment rapidement. Du fait de leur caractéristique de bien public, ces réserves peuvent être fournies en quantité insuffisante par les acteurs de marché (producteurs, consommateurs…), pouvant ainsi mettre en danger l'équilibre du système. C'est pourquoi les Gestionnaires de Réseau de Transport (GRT) sont obligés d'intervenir directement pour assurer la disponibilité de ces réserves en quantité suffisante. Le modèle mis en place pour assurer cette disponibilité est appelé modèle de sûreté.

En particulier, deux grandes stratégies de constitution des réserves (i.e. deux modèles de sûreté) sont au cœur de cette première partie de la thèse : le modèle dit « réserves », mis en place notamment en Allemagne ou aux Pays-Bas, et le modèle dit « marges » mis en place en France. Ces deux modèles se distinguent essentiellement par un suivi dynamique des marges disponible et requise qui n'est possible que dans le modèle de sûreté dit marges. Une conséquence pratique de ce suivi ou non des marges est le niveau de contractualisation des réserves. Le modèle de sûreté réserves (appelé modèle de sûreté alternatif dans cette thèse) contractualise un niveau élevé de réserves à la hausse et à la baisse pour pouvoir faire face à tous les aléas possibles en temps réel. En effet, ce modèle de sûreté ne dispose d'aucun recours dans le cas où les réserves contractualisées ne sont pas suffisantes en temps réel : cela impose alors au GRT de contractualiser un niveau volontairement élevé de réserves pour éviter tout risque de ne pas pouvoir faire face à un aléa important. Au contraire, le modèle de sûreté marges (appelé modèle de sûreté français dans cette thèse) contractualise un niveau plus faible de réserves car le GRT est capable, grâce à un suivi dynamique des marges requise et disponible, de détecter une situation problématique et d'y remédier en activant des offres pour cause marge proche du temps réel afin d'apporter de la réserve supplémentaire au système si cela est

nécessaire. Cela consiste notamment à démarrer des centrales thermiques qui autrement resteraient éteintes et ne participeraient pas à la sûreté du système.

Dans un contexte européen où les questions d'équilibrage et de réserves sont de plus en plus discutées d'un point de vue économique, la comparaison des performances économiques des deux *designs* des modèles de sûreté mentionnés ci-dessus gagne en intérêt. Toutefois, la littérature actuelle ne permet pas d'éclairer les décideurs publics sur les propriétés économiques de ces modèles. Cela constitue l'objectif de cette première partie de la thèse, à savoir évaluer quantitativement les effets sur le surplus social qu'aurait, pour le système français, le passage du modèle marges actuel à un modèle de sûreté de type réserves.

A continuous balance in real time between generation and load is essential to ensure the security of the power system. Since imbalances always happen in real time because of forecast errors regarding generation or consumption, the main solution to avoid major rolling blackouts lies in the activations of reserves by the TSO in real time: the strategy of activation of reserves is called the balancing model and will be introduced in the first section of this chapter. However, to be able to activate enough reserves in real time, the TSO has to be sure of their presence in a sufficient volume. It is the aim of a second model, called the security model, which will be introduced in the second section. These two complementary models are illustrated in a simplified way in figure 1.

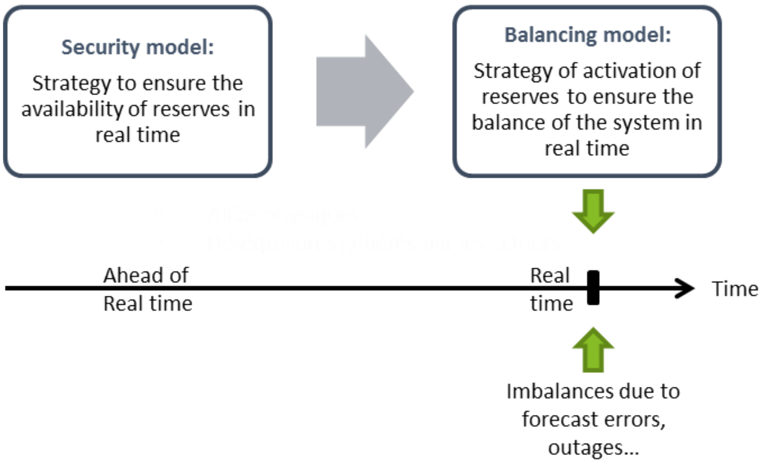

Figure 1: Simplified illustration of the security and balancing models

Even if the efficient design of both models from an economic point of view has been given relatively little attention by academic researchers at the beginning of market reforms, they are now at the centre of market design discussions, especially in Europe. In particular, policy makers aim at improving the efficiency of both models and at adapting them to the impacts of the massive development of renewable energy. Moreover, the will to create a common power market across Europe results in several discussions about integration and harmonization of balancing and security models for some years.

Within this context, the French security model, which exhibits a peculiar design compared to other solutions implemented in Europe (and which will be described in the third section), and its economic performances have gained some attention. In particular, the French regulator has asked the French TSO to perform a quantitative analysis to study the costs or benefits that would bring a change of security model. However, the economic study of the French security model was never performed in the current literature: insights to assess whether the French TSO should modify the way it ensures the presence of enough reserves for real time are then very limited. This part of this thesis then aims at filling the gap in current literature. The last section of this chapter will introduced the research question and how it is related to the current relevant literature.

1.1. The need to activate reserves in real time to ensure balance between supply and demand: the role of the balancing model

This subsection introduces the main principles applied to ensure the balance between power supply and demand in real time. Activations of reserves by the TSO, i.e. capacities which are available to modify their generation (in case of power plants) or their load (in case of consumers) levels, are necessary. The main different strategies of activations are also quickly presented.

1.1.1. The necessity of a continuous balance in real time

A continuous balance in real time between generation and consumption is essential to ensure the stability of the frequency and then the stability of the power system as a whole: the ability of the power system to support unexpected disturbances close to real time is called the security in the literature (Rodilla, 2010). Imbalances in real time are very difficult, or even impossible, to avoid entirely. Indeed, forecasts of demand and supply are complex and always flawed, resulting in discrepancies that should be solved in real time. Regarding the demand side, forecast depends on the aggregated behaviour of millions of consumers, whose power demand highly fluctuates subject to many variables, like the temperature or the cloud cover, which cannot be anticipated perfectly. The absence of real-time measurement of consumption for households in most countries so far also limits the accuracy of forecasts (Motamedi et al., 2012; Sauhats et al., 2015). The generation level can also be difficult to predict. This difficulty is twofold depending on the type of power plants. For traditional power plants like nuclear, coal-fired or gas-fired plants, unplanned outages can dramatically change their production level in real time[2]. Regarding the intermittent renewable generation (wind, photovoltaic…), the main source of incertitude lies in the difficulty of forecasting the weather exogenous factors (wind direction and speed, amount of sunshine…) which are directly correlated to power generation. Even if forecasting methods have improved (Bruninx and Delarue, 2014; Wu and Hong, 2007), the current massive penetration of these intermittent technologies in Europe will likely raise the imbalances in real time (Holttinen et al., 2011; Mauch et al., 2013; Pudjianto et al., 2013).

1.1.2. Reserves as the solution to solve imbalances

Since imbalances cannot be avoided, the TSO has to compensate them in real time to ensure the security of the power system. To this end, some capacities (mainly from power plants but also from demand response) should be available in real time to modify either their generation or their load level quickly enough: these available capacities are called reserves. They can be upward (they are activated when supply is lower than demand, i.e. they imply an increase of the generation level or a decrease of the load level) or downward (used when supply exceeds demand). Moreover, because of the impossibility to store electricity on a large scale, the modification of the generation or the load level should be done as soon as imbalances appear. However, this change cannot be made instantaneously and volumes of reserves provided by power plants are limited because of their technical constraints (for instance, their ramping constraints[3]). That is why, based on their response time (i.e. how fast reserves can react to a request to change their generation or load levels), three types of reserves are distinguished and used consecutively in Europe as illustrated in figure 2 (ENTSO-E, 2013).

[2] Similarly, unplanned outages can happen on the network, which will have the same consequences.
[3] I.e. to what extant power plants can increase or decrease their production level during a given duration (for instance, one hour).

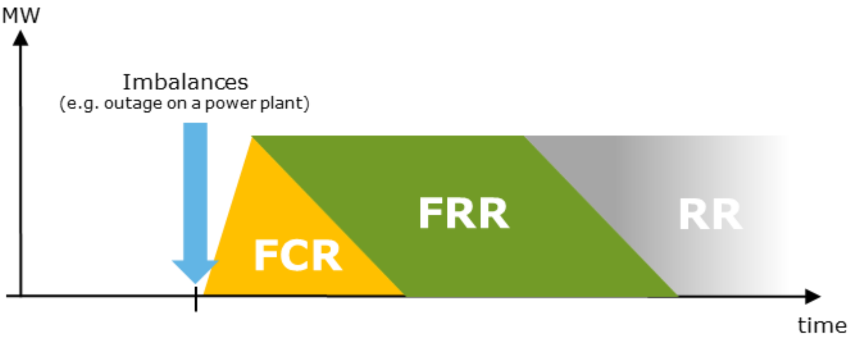

Figure 2: Different types of reserves activated in Europe

Frequency containment reserves (FCR): Following the occurrence of a disturbance, FCR are activated first at very short notice, generally in less than 30 seconds, to stabilize the frequency (but at a value different from the reference one).

Frequency restoration reserves (FRR): To replace the previously activated reserves (in case another disturbance happens) and to restore the frequency at its reference value, the frequency restoration reserves are called. They must modify their output in less than 15 minutes.

Replacement Reserve (RR): Finally, to restore the previously activated reserves, a third kind of capacity can be activated, the replacement reserves. Their activation time ranges from 15 minutes to hours.

1.1.3. Different strategies to activate the reserves in order to solve imbalances

Strategies to activate the different reserves to address imbalances and then the rules governing these activations are referred as the balancing model in this thesis. Even if the principle of activating reserves to restore the balance is shared in Europe, the strategy to activate them widely differs. Among these differences, two main ones, which are important for the characteristics of the French power system, are briefly exposed in the following sections.

1.1.3.1. The extent to which activations of reserves are left to the market

To solve the imbalances, reserves should be deployed quickly, in particular for FCR and aFRR. Current technologies are not believed to enable a free market to perform this. For instance, in case of an outage on a power plant at time t, the producer which owns this plant should find quasi instantaneously[4] a counterpart which will produce the amount of electricity it cannot deliver (or accept to reduce its load level) so that the balance between supply and demand is maintained and there is no security issues. Current IT technologies do not enable markets to perform such a fast transaction (or at prohibitive transactions costs). Then, activations of the reserves with a short response time should not be left to the market but regulated and overseen by a centralized and non-market based player, namely the system operator (called the Transmission System Operator, TSO, in Europe), thanks to a more centralized[5] or automatic solution (Boucher and Smeers, 2002; Saguan, 2007; Wilson, 2002).

However, while market does not enable market players to react in few seconds, it can be the case for longer timescales. In the previous example, while the producer cannot find a counterpart in few seconds using the market, it may succeed in doing it in 30 minutes or 1 hour, for instance by formulating bids on the intraday markets. Market players are then believed to react to their imbalances for longer timescale and the use of non-market based solutions overseen by the TSO are only temporary.

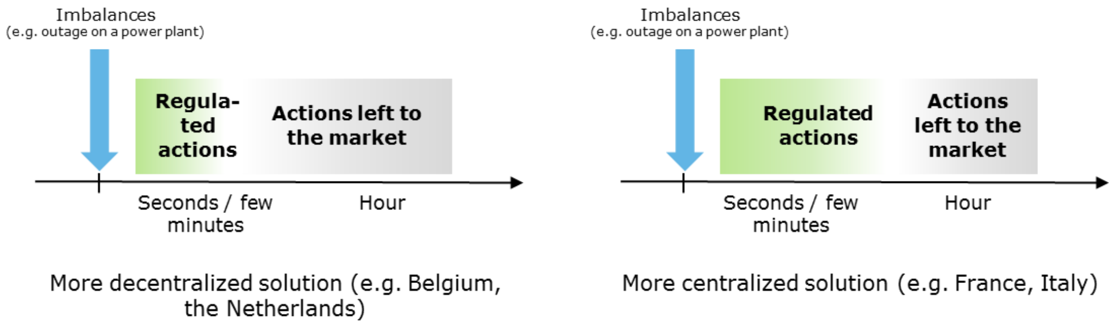

Figure 3: Regulated and market-based actions to solve imbalances

The separation between the interventions which can be left to the market and those which cannot is not clearly defined and different visions coexist in Europe, as illustrated in figure 3. For instance, in Belgium or in the Netherlands, market players are believed to be able to react in 15 minutes to an imbalance (Elia, 2013). In particular, the market is designed in a way to enable this, for instance by incentivizing financially market players to react

[4] Indeed, even imbalances during few minutes can have serious consequences on the power system.
[5] Even if actual activations are performed by decentralized market players using their own plants, the decision to perform these activations are required by the centralized TSO.

quickly and by enabling trades on a short timeframe on intraday markets. Thus, RR (whose response time is more than 15 minutes) are not needed in these countries and the TSO solves imbalances for very short timescales only, using FCR and FRR. This activation strategy is then defined as more decentralized (even if it stays centralized at some point). On the contrary, others countries, like France or Italy, consider a longer timeframe for regulated activations of reserves supervised by the TSO. For instance, the French TSO can activate RR whose response time is 30 minutes (RTE, 2016). In Italy, RR can be activated up to 2 hours (Oggioni and Lanfranconi, 2015). This activation strategy is defined as more centralized.

1.1.3.2. The anticipation (or not) of the imbalances by the TSO

Another important difference between balancing models in Europe lies in the anticipation that the TSO may perform of future imbalances. Indeed, based on its own forecasts, the TSO can anticipate some future imbalances before they really happen and solve them in advance. Thus, two types of approaches may exist: the reactive approach (without any anticipation) and the proactive approach (with some anticipations of future imbalances).

With a reactive approach, the TSO does not anticipate such imbalances and only observes them in real time. It then uses the aforementioned reserves (FCR, FRR and eventually RR) to restore the frequency at its reference value. In order to avoid resolving large real-time imbalances that would require large activations of the most expensive reserves (FCR and FRR), market participants are encouraged to take more responsibility for energy balancing until real time, for instance though price signals (Håberg and Doorman, 2016; Pentalateral Energy Forum, 2016). This reactive approach is currently implemented in the Netherlands or in Belgium (Pentalateral Energy Forum, 2016).

Within a proactive approach, the TSO tries to anticipate the future imbalances and then activates reserves in advance to solve them before they really happen. It enables the TSO to activate more reserves with longer response time (like RR), as it can anticipate their use ahead of real time, and then less fast reserves (FCR and FRR), which are more expensive. However, the TSO cannot anticipate perfectly all imbalances; activations of FCR and FRR are still needed (but are reduced compared to the reactive approach) and the TSO is not purely proactive. France or Great Britain are two examples where the TSO is proactive[6] (Pentalateral Energy Forum, 2016). For instance, in France, this approach translates into a resolution of 80% of imbalances up to 2 hours before the real time (RTE, 2016).

Both approaches aim at reducing the balancing costs but in different ways (Pentalateral Energy Forum, 2016). A reactive TSO reduces the volume of imbalances by making market players more responsible but solves them with costly reserves. On the contrary, a proactive TSO solves imbalances with cheaper reserves but imbalances tend to be larger since marker players are less incentivized to reduce them.

1.1.4. The importance of the price signal sent to market players to reflect activations undertook by the TSO

Once reserves have been activated to solve imbalances, the definition of the corresponding price is essential. Indeed, even if the TSO oversees their activations, it only acts as a coordinator to replace the market. Thus, costs incurred by these activations should not be supported by the TSO but by market players responsible of the imbalances. For this purpose, the concept of Balancing Responsible Parties (BRP) has been created in Europe. BRPs are market players which are financially (and sometimes legally) responsible for imbalances within their portfolio (i.e. they are responsible for the difference between, on the one hand, how much they produce and they buy on energy markets, and, on the other hand, how much their clients consume and how much they sell on markets). If the portfolio is not balanced in real time, the TSO solves these imbalances instead of the BRP and charge for it afterwards: this is called the imbalance settlement and the corresponding price the imbalance settlement price (ISP).

The way ISP is computed may modify the behaviour of market players, and in particular how they balance their portfolio, and finally the overall deviations of the system in real time. Moreover, this price, as the only true spot price of electricity, impacts the prices of forward markets, from futures to day-ahead and intraday markets (Hirst, 2001). Different solutions are suggested nowadays in Europe, which could have different properties, for

[6] It should be noted that the proactive strategy is partly related to the degree of centralization previously described. If the TSO is highly decentralized and cannot activate RR, the proactive activation is almost impossible to perform (or useless since the TSO cannot activate cheaper reserves such as RR).

instance in terms of incentives sent to market players to participate to balancing, of economic efficiency or in terms of risk of market power abuse[7].

1.2. Ensuring the availability of enough reserves in real time: the aim of the security model

The previous section highlights the importance of having different types of reserves in real time so that the TSO is able to ensure the frequency stability. These reserves should be available in sufficient quantity to deal with likely imbalances. The TSO often defines the right level of reserves based on statistical analysis[8], especially in function of possible imbalances[9]. In particular, it should be noted that the total level of needed reserves tends to decrease as real time gets closer (Pinson et al., 2007). Indeed, close to real time, forecasts (about consumption, wind speed…) become more and more precise and then the imbalances, caused partly by these forecast errors, are reduced.

In this chapter, the focus is made on the way the TSO can ensure the presence of the reserves in real time, once their relevant level has been defined. The model implemented to guarantee their presence is called security model[10] in this thesis. In the following paragraphs, the main strategies to ensure the availability of reserves and implemented in Europe are presented. In particular, the French security model, which is quite original compared to others in Europe, is described in more details as it will be at the centre of the research question of this part of the thesis.

[7] Interested readers on this subject, which is currently being extensively debated in Europe, may refer to Chaves-Ávila et al. (2014), Glachant and Saguan (2007), Nobel (2016), van der Veen (2012), van der Veen et al. (2012) or Vandezande (2011).
[8] Indeed, the TSO does not seek to hedge against exceptional deviations with a tiny risk of appearance. A criterion is then defined, for example to protect against 99.9% of possible imbalances.
[9] The question of the determination of the right level of reserves is not studied in this chapter. Interested readers can refer to Bucksteeg et al. (2016) or Hirth and Ziegenhagen (2015) for further information.
[10] To the knowledge of the author, this term is used exclusively in France. Other countries do not seem to use a precise term to describe this task.

1.2.1. As public good, reserves can be undersupplied by market players: the TSO needs to intervene to ensure their availability

Producers[11] are able to provide reserves in real time to the TSO if they can modify the generation of their power plants quickly enough (for instance in less than 30 seconds for the FCR). It usually requires that power plants are already online. Moreover, to provide upward reserves, a plant cannot produce at its maximum level. For downward reserves, it has to produce above its minimum output. Finally, depending on the type of reserves (FCR, FRR or RR), due to its ramping constraints, the plant can modify its generation in a limited quantity only which reduces the reserves it can provide. If these conditions are met, producers can then provide some reserves to the TSO which will be able to activate them in real time if necessary. However, several points limit to what extent the TSO can rely on these capacities to help balancing the system.

Firstly, the reserves that power plants can provide close to real time is very uncertain. Indeed, as illustrated in a simplified case in figure 4, in the case of upward reserves, a producer is more likely to use a sole power plant and produce near its maximum level than to produce the same quantity but with two plants (in the second case, it may bear two start-up costs and higher operational and maintenance costs). However, upward reserves provided to the TSO are different between these two cases whereas the total generation is the same.

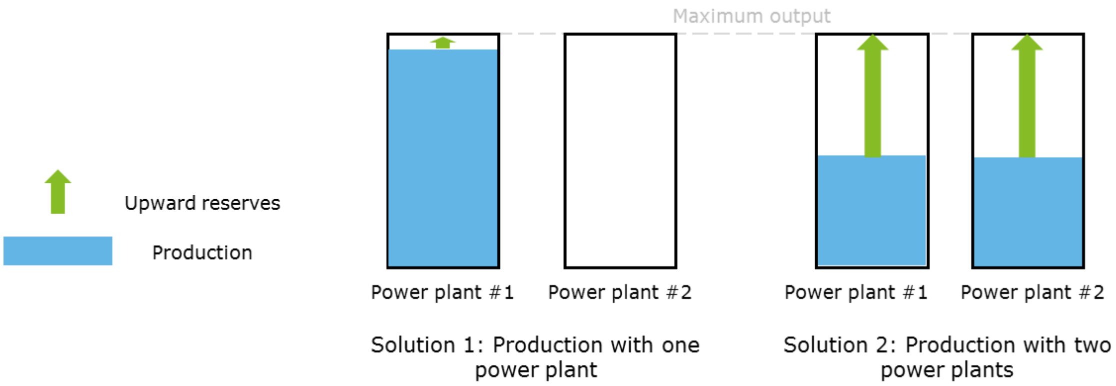

Figure 4: Provided upward reserves depending on the production decisions - illustration

[11] In the following paragraphs, different notions will be illustrated using the case of a power plant for simplicity. The same can obviously be done for demand response.

Since reserves are public good (Müsgens et al., 2014; Saguan, 2007)[12], producers are not incentivized to value them in the second case of figure 4 and they base their generation decisions on their private costs and profits only: the more likely generation schedule is then the first one. In this case, the TSO can rely only on a limited volume of reserves to solve imbalances. Available capacities in real time are then very uncertain since they depend on generation decisions made by market players which are generally not incentivized to keep reserves. Consequently, there is a huge risk for the TSO to rely only on reserves that power plants will provide in real time since their level is difficult to anticipate and may vary depending on generation decisions.

Secondly, even if power plants have available capacities in real time, the TSO may be unable to activate them. Indeed, if these plants do not offer this possibility to the TSO (by telling it that they have available capacities), the TSO may not know their presence and cannot rely on them to balance the system. To solve this issue, plants can be incentivized financially to offer their reserves. For instance, if they lose money with the activation, they will certainly not offer their reserves to the TSO. Then, activation should be at least financially neutral for market players. Moreover, in some countries, market players have an obligation to offer their available capacities to the TSO so that it can use them to solve imbalances. For example, if a plant produces at 200 MW and its maximum output is 300 MW, the market player has to make these 100 MW available for the TSO if it needs them to solve imbalances (in other words, the market player cannot retain these 100 MW). However, they are not required to modify their generation schedule especially to offer some to the TSO. For instance, if a power plants is scheduled to produce at its maximum output, it does not have any available capacities: in this case, it is not obliged to change its generation schedule to offer some reserves to the TSO. This obligation is notably enforced in France for plants connected to the transmission grid (RTE, 2018). Nevertheless, even with this obligation, nothing ensures that the reserves, as a public good, will be sufficient since their availability still results from actions of private market players.

[12] A market player which provides reserves to the system cannot exclude someone else to benefit from these reserves (if the first market player use these reserves to balance the system, it will avoid a blackout which will benefit to itself but also to all players connected to the network). Moreover, reserves are non-rivalrous (once reserves are provided, there are unaffected by the number of market players which can benefit from them, i.e. the number of players connected to the network).

Thus, to ensure to have enough reserves in real time and to solve the public good issue, the classic solution implemented in all European power systems is to procure the reserves in advance of real time through a new market called the reserves procurement market. On this market, the TSO defines a demand for reserves and market players submit bids reflecting their costs to provide them. If their bids are accepted, they should then keep some capacities available in real time to provide these reserves to the TSO; producers will schedule their generation level considering these constraints of reserves provision. The forward procurement of reserves through financial commitment (market players must often pay high penalties if they are unable to honour their reserve commitments) then ensures the TSO to have a minimum level of reserves in real time to deal with imbalances.

1.2.2. Different security models in Europe to ensure the availability of reserves

As explained previously, a TSO can rely on several ways to ensure the availability of reserves (cf. table 1): in particular, it can procure them forward through a market or it can rely on reserves provided by market players without procurement. For simplicity, this latter type of reserves is called voluntary reserves or voluntary bids in this chapter, by contrast with procured reserves.

Table 1: Two main ways to provide reserves

Solutions to ensure the availability of reserves	**Certainty of their availability in real time**
Reserves provided through voluntary bids (without previous procurement)	Uncertain (depend on market players' decisions)
Reserves provided through forward procurement market	Certain (legal and/or financial commitment)

In Europe, TSOs have implemented several solutions to ensure the availability of these reserves which differ in the extent they rely on procurement or on voluntary bids. In other words, several security models coexist. Even if they present several differences which are not well described in the literature, it is possible to distinguish three main solutions in

Europe. These solutions mainly differ in the actions the TSO can perform to ensure the presence of sufficient reserves in real time.

1.2.2.1. A centralized management of reserves with a large possibility of actions of the TSO: the central-dispatch model

In a first solution, the TSO ensures the availability of sufficient reserves in real time by determining itself directly the commitment and output of power plants: this is the central-dispatch model implemented in some European countries like Italy or Poland (ENTSO-E, 2017) but mainly in US markets. Greatly simplified, within this model, based on the results of energy markets, on technical constraints (of the power plants but also of the network) and on the need of reserves, the TSO performs a centralized unit commitment to decide how plants should produce while complying with operational security requirements and congestions. It enables the TSO to ensure the availability of enough reserves at least cost. For instance, regarding the figure 4, with this security model, the TSO may ask power plants to produce as in the second configuration since it increases the availability of reserves for the same level of generation (if no cheaper solution exists) (ECCO International, 2014). Since the TSO has extensive possibility of actions over the commitment of power plants, it determines itself the reserves they will provide in real time. Then, there are no uncertainties for the TSO on their level.

Contrary to the first solution, the two following types of security model are based on a self-dispatch model: producers determine themselves the commitment of their plants, based mainly on their technical constraints and on what they sold in energy markets. A self-dispatch model is implemented in most European countries, like France, Germany or the Netherlands (ENTSO-E, 2017). In that case, the TSO cannot really rely on reserves that market players may provide without procurement since they depend on market players' decisions which can be difficult to anticipate, especially far from real time. The TSO then needs to procure reserves in advance, for instance thanks to auctions. Moreover, to give enough flexibility to power plants to modify their generation schedule and then be able to provide these reserves, the procurement phase generally takes places before the day-ahead market (it can even take place several months before in some cases) (ENTSO-

E, 2017). This decentralized management of reserves can be seen as a shift of responsibility from the TSO to the market players through the commitment of the reserves market. Moreover, within the self-dispatch model, two main security models can be observed depending on what extent the TSO can react to ensure the availability of an adequate level of reserves.

1.2.2.2. A decentralized management of available capacities without any actions of the TSO except the procurement: the reserves approach[13]

In the reserves approach, the only solution for the TSO to have enough reserves in real time is thanks to procurement. In particular, it cannot modify the schedules of power plants before the real time if it reckons that balancing may be jeopardized. Then, the TSO cannot rely on voluntary bids since it cannot be sure about their level on real time. Consequently, it should procure a level of reserves high enough to deal with likely imbalances in real time, even in the worst cases where there are no voluntary bids. Moreover, as the procurement phase generally takes place at least before the day-ahead market (which clears at 12 p.m. the day before the delivery), forecasts about likely imbalances in real time are not very acute. Then, the TSO needs to procure a voluntary high level of reserves to deal with almost all possible situations, whatever happens between the procurement phase and the real time. In particular, the level of procurement cannot evolve depending on new information on consumption or weather. The reserves approach is currently implemented in the Netherlands, Belgium or in Germany (RTE, 2016).

1.2.2.3. A decentralized management of available capacities with some actions of the TSO: the margin approach

In the margin approach, the TSO still procures some reserves forward. Besides, contrary to the previous solution, it can react if it reckons that reserves will not be sufficient in real time to solve imbalances. More precisely, the TSO tries to evaluate the reserves which will be provided without procurement by market players. If these reserves added to the previously procured reserves are not sufficient to deal with possible imbalances, the TSO will increase the level of reserves by activating special bids called activations to ensure

[13] There are few discussions about security models in the literature. Then, in this thesis, the author uses the denomination of the French TSO to qualify the different solutions of security models.

system margin (cf. explanations in the next section). The TSO has then a certain flexibility to ensure the availability of additional reserves; this solution can be seen as a trade-off between both previous solutions (even if it is closer to the reserves approach since a self-dispatch model is applied). Consequently, the level of procurement can be reduced compared to the reserves approach. This security model is implemented in France where it is called the margin approach.

The three main philosophies of security models are summarized in table 2.

Table 2: Three main security models depending on the possible actions of the TSO to ensure the availability of sufficient reserves besides procurement

	Central-dispatch	**Self-dispatch**	
		Reserves approach	Margin approach
Possibility of actions for the TSO to ensure the availability of sufficient reserves in real time besides procurement	High by deciding itself the final dispatch of each plant	None	Medium thanks to activation to ensure system margin
Examples of countries	Italy	Germany	France

1.2.3. Functioning of the French security model

The French security model, whose mechanism was already in place before the beginning of market reforms, is quite unknown in the literature, even for French market players, and is more complex to understand than the classic reserves approach. Hence, the French security model is described in broad outline in the following paragraphs. In particular, a simplified and qualitative comparison between the margin approach and a more traditional reserves approach is presented.

1.2.3.1. Computation and comparison of the required and available margins

To ensure the security of the power system, the French TSO computes and compares two values: the required margin and the available margin. Both are explained below and in more details in the section focused on the modelling of the French security model.

1.2.3.1.1. Required margin

Regarding the required margin of the system at time t, it represents the minimum volume of reserves that the system must have available at time t in order to cope with possible large imbalances and avoid resorting to exceptional solutions like rolling blackouts[14]. Two required margins are computed: the upward margin (i.e. the volume of power necessary to deal with negative imbalances) and the downward margin (to deal with positive imbalances). The required margins are assessed by the TSO at different times (for instance, 4 or 3 hours before the real time) based on probabilistic studies which consider the current situation of the power system to refine the computation (for instance, the level of consumption or the wind speed). In particular, the required margin decreases as the real time gets closer since their computation becomes more and more deterministic and large imbalances become less likely.

1.2.3.1.2. Available margin

The French TSO also computes the upward and downward available margin of the system for the time t. In the case of the available upward margin, this margin characterizes the additional volume that the whole system could produce at time t if necessary. It is always computed relatively to a duration. For instance, a 4-hour available upward margin represents the quantity of additional power the system can provide at time t if the generation schedule is modified during 4 hours before time t only. The available margin comes from the procured reserves (which can modify their generation quickly enough, e.g. 15 minutes) but also from the capacities that are not procured but which can modify their output if needed (voluntary bids). Several examples of available margins for two power plants are described below. In the first case (figure 5), the power plant is online: in a simplified way, the 4-hour upward margin for time t which it provides to the system is equal to the difference between its scheduled generation level for time t and the maximum generation level it can reach by modifying its output during 4 hours before time t. This margin is limited by the technical constraints of the plant, notably its maximum output as in case 1 of the figure 5 and its ramping constraints as in case 2 of the figure 5. In figure 6, the power plant is offline and its start-up time is equal to 4 hours. This power plant can

[14] In particular, the required margin is defined by the French TSO so that the risk of using exceptional solutions is lower than 1% for the peak of demand during the morning and 4% for the evening peak.

provide available upward margin for the system in 4 hours but cannot in 3 hours because it is not able to finish its start-up in 3 hours only. Thus, the TSO does not consider this plant in the 3-hour available upward margin.

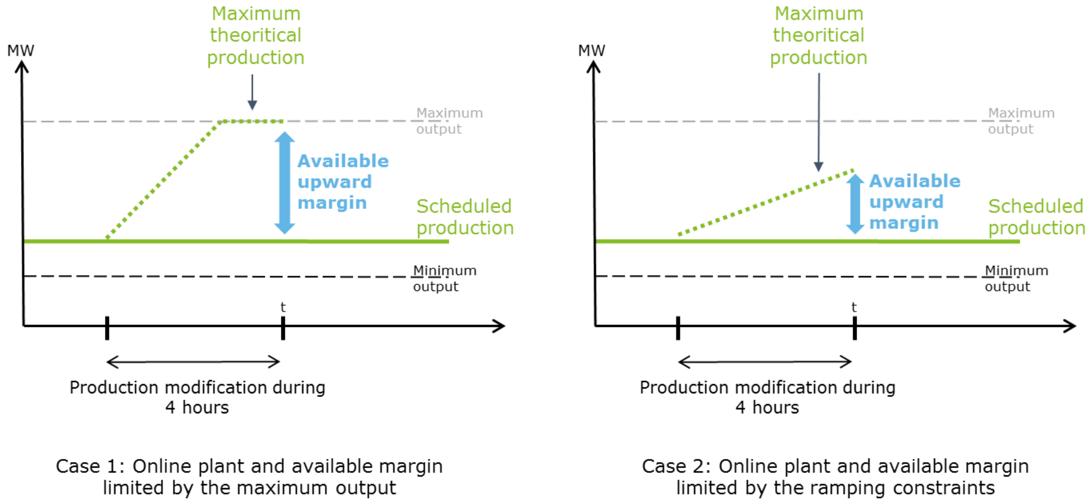

Figure 5: Examples of available upward margins for an online power plant

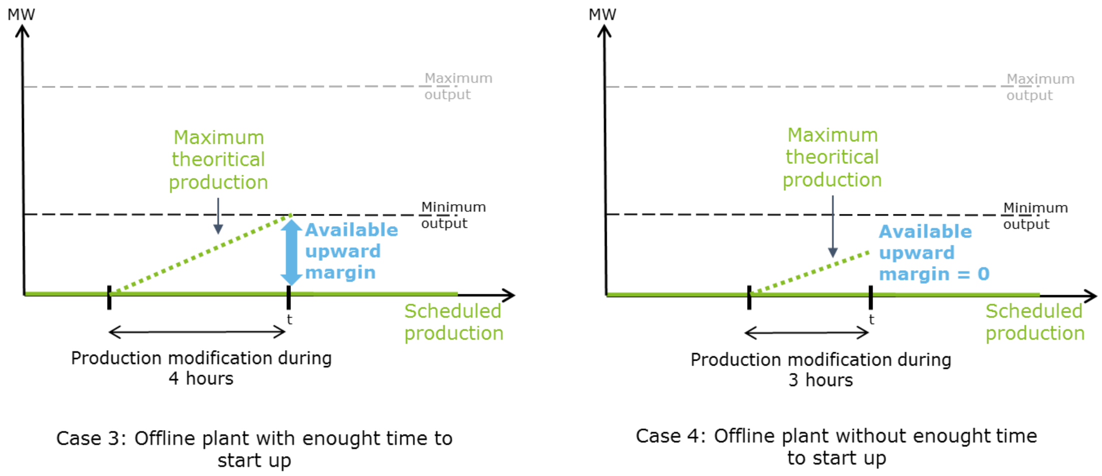

Figure 6: Examples of available upward margins for an offline power plant

The total margin of the system can then be assessed as the sum of the margin provided by each power plant (and possibly by demand response). It should also be noted that this available margin is not activated by the TSO. Calculations are only theoretical and the TSO does not ask power plants to modify their generation during 4 hours. It only ensures the presence of sufficient capacities so that the system can react if a serious imbalance happens during these 4 hours.

The TSO also computes the available downward margin, i.e. the maximum level of power that can be decreased on the entire system over a given duration if necessary. Computations are comparable to those for the upward margin. This margin is also limited by technical constraints, in particular the ramping constraints and the minimum output.

1.2.3.1.3. Comparison of the required and available margins

Once the TSO has computed the required and available margins, it compares them to study if security is at risk and if it needs to intervene. If the available margin is lower than the required margin, it means that in case huge imbalances happen (for instance, outage on a power plant, large forecast errors), the system does not have enough available capacities to react and rolling blackouts may occur. Moreover, the comparison is carried out dynamically, i.e. the TSO does it several times in advance of the real time (for instance, every 30 minutes). Far from real time, the level of required margin is high because uncertainties about the state of the system in real time are strong. However, the TSO can rely on many capacities in the available margin since, far from real time, plants can modify their generation level in large amounts (in particular, plants have enough time to start up if necessary see figure 6). This point is illustrated in figure 7.

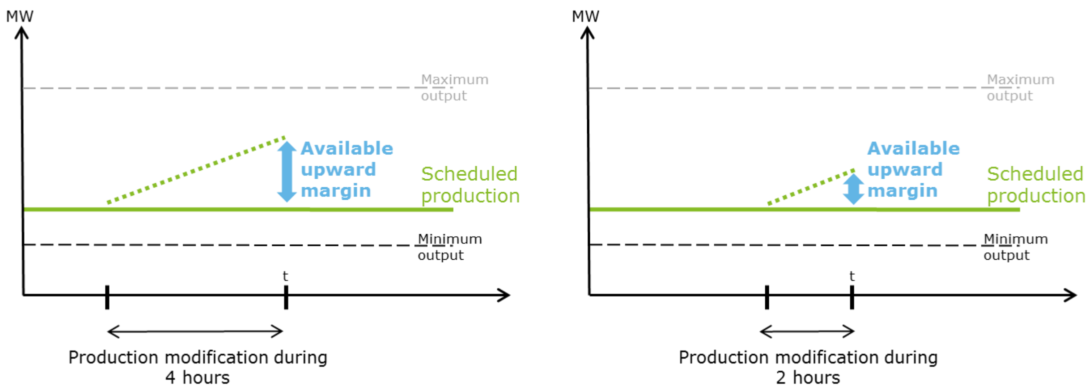

Figure 7: Evolution of the available upward margin when approaching real time - illustration

Getting closer to real time, the required margin lowers (uncertainties are reduced as some extreme scenarios can no longer occur), as does the available margin. Thus, the dynamic approach enables the TSO to consider properly the state of the system (for instance, the level of consumption but also how plants plan to produce). The difference between the required and available margins, if any, can then be reduced compared to a static comparison which often considers the worst case scenario.

1.2.3.2. Activations to ensure system margin

In the particular case where the available margin level is not sufficient to meet the required margin level, the TSO carries out specific actions to increase the level of available margin: these actions are called activations to ensure system margin. In practice, in the case of the upward margin, they consist in starting up power plants several hours before the real time. In such cases, the TSO remunerates activated plants to cover their costs. Moreover, these activations are chosen considering their technical characteristics and their costs (cheaper solutions are activated first).

For instance, if a power plant is offline and requires 4 hours to start up, it cannot be accounted for in the 3-hour available margin (see figure 6). Then, if this available margin is not sufficient, the TSO may require this plant to start up 4 hours before the real time. Henceforth, since this plant is now online, it will provide some upward margin which would not have been possible had it not been activated beforehand because of its long start-up time. In particular, this plant will produce electricity at its minimum output level; its production will increase the available margin and then improves the security of the power system. Similarly, in case of insufficient downward margin, the TSO may require a power plant to shut down.

Thus, if the TSO anticipates several hours before real time that the available margin level is below the required level, it can react accordingly by increasing the level of available capacities and then avoids the risk of not achieving balancing.

1.2.3.3. Consequences on the procurement level

The characteristics of the French security model can be summed up in two points:

- Firstly, the need of reserves to deal with possible imbalances is computed dynamically and is updated with the current situation of the power system. Whereas this need is defined based on the worst situation that can happen in real time with the reserves approach, the margin approach enables to refine it and to dismiss the worst scenarios that are no longer likely given the current state of the power system.

- Secondly, the TSO can rely partly on capacities made available by market players without procuring them. If these capacities are not sufficient, it can react by activating special bids (the so-called activations to ensure system margin) to increase available capacities in real time, which is not possible in the reserves approach.

Thus, combining these two characteristics of the French security model enables the TSO to procure a smaller level of reserves than in the reserves approach, all other things being equal. The remaining reserves to ensure security are provided by available capacities of power plants which are not procured and by activations to ensure system margin if needed in last resort.

The lower reserves procurement in the margin approach mainly concerns reserves with the longest activation times (in particular RR). Indeed, FCR or aFRR are essential for the security of the power system and must follow very stringent technical requirements so that they can be activated automatically. Even in the margin approach, the availability of these reserves is ensured entirely through procurement. For the French power system, the possibility of activations to ensure system margin enables to decrease the procurement level of RR only compared to the reserves approach (see section 3.3.1 for the values).

1.2.3.4. Requirements to ensure the success of the margin approach

To work efficiently, the French security model requires several conditions:

- Firstly, market players must have an obligation to provide their available capacities to the TSO in real time. If not, the TSO is never sure whether it can rely on these reserves for solving the imbalances and then whether it can count them in the available margin.
- Moreover, the TSO needs a very detailed forecast information about the status of the power system, in particular regarding the generation schedule of power plants to be able to compute their available margin. This is made possible by the fact that producers in France have an obligation to send information to the TSO about their scheduled generation on a unit level.
- The TSO also needs the possibility to activate bids to ensure system margin far from the real time to increase margin if needed (since these activations usually require the start-up of power plants, they take place several hours before the real

time). This is the case in France. However, if the TSO can act close to real time only (for instance 30 minutes before), activations to ensure system margin cannot be performed and the margin approach becomes similar to the reserves approach with a high level of procurement.

- Finally, this security model requires some experience of the TSO, in particular to compute the required margin and the available margin. The French TSO has learnt to manage it (in particular since this mechanism was in place before the beginning of market reforms) but this approach may not be adapted to other systems.

1.2.3.5. Comparison of the reserves and margin approaches

To conclude, figure 8 summarizes in a simplified way the main differences between the reserves approach and the margin approach for upward reserves. In particular, to simplify, the dynamic comparison implemented in the margin approach is not illustrated on this figure. With the reserves approach, the TSO procures a high level of reserves, based on the highest need. Indeed, procurement is the only solution for it to ensure the availability of these reserves in real time, whatever happens between the procurement phase and the real time. With the margin approach, the level of procured reserves can be reduced compared to the highest need. The difference between needed and available reserves is provided by market players (without procurement) and, if it is not sufficient, by activations to ensure system margin (in red in figure 8).

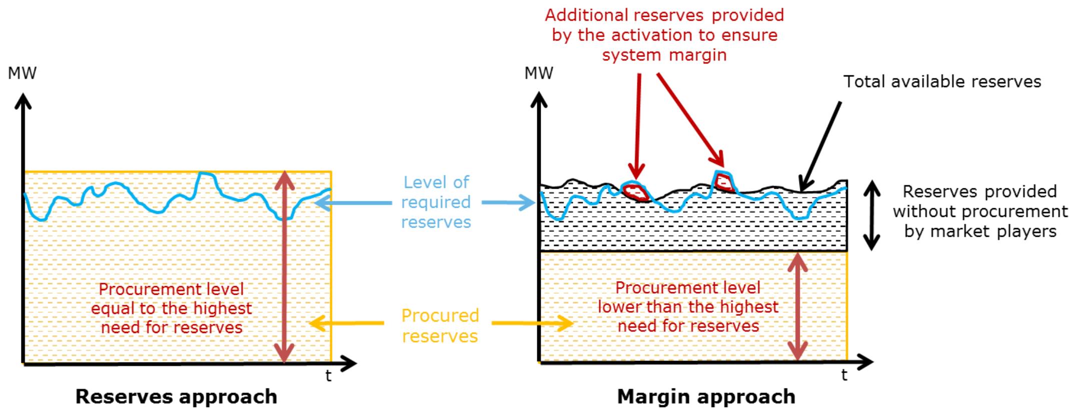

Figure 8: Simplified comparison of the reserves and the margin approach

1.3. Characteristics and differences in balancing and security models are at the centre of market design discussions in Europe

As seen in the previous sections, different solutions of balancing and security models are chosen in Europe. It then raises more and more discussions these recent years for several reasons as explained in the first part of this section. As a result, academic literature studies the best market design to implement to ensure the security of the power system according to several criteria: these recommendations are summed up in a second part. However, the comparison of the different design of the security models and in particular the economic characteristics of the French one compared to a reserves approach are never studied in the economic literature: this will be the research question of this chapter as presented in a last part.

1.3.1. Three main reasons to the increasing interest for the design of balancing and security models

The design of the balancing and security models has been more and more discussed these recent years in Europe. The main goal is to decrease their associated costs. In Europe, actual overall costs of balancing (capacity and energy) range from about 0.5 € per MWh of national consumption to more than 5 € (ACER and CEER, 2017). A large share of these costs are due to the reserves procurement costs. They can then represent a significant amount for one year. For instance, in France, reserves procurement costs amount up to € 260 million a year for the French TSO (CRE, 2016). In Germany, they are equal to about € 600 million a year (Hirth and Ziegenhagen, 2015). The growing interest for a better design of balancing and security models is then relevant regarding the amounts at stake. In particular, three main reasons for improvement can be mentioned in current discussions.

Firstly, the design of these models has been given relatively little attention by academic researchers at the beginning of market reforms (Glachant and Saguan, 2007; van der Veen and Hakvoort, 2016). Focus was mainly on day-ahead market, forward markets or over the counter market which deal with the majority of trading volume. Moreover, the real-time market can be seen more as a pseudo market with the intervention of centralized agent, the TSO, to ensure the balance between supply and demand than a pure market between private players only. That is why several European TSOs decided to compute ISP using penalties and/or a dual ISP because they feared that a real marginal price may incentivize market agents to intentionally create imbalances and then jeopardize the security (Glachant and Saguan, 2007; Littlechild, 2007). Solutions based on weaker economic justifications than the marginal cost could have then been preferred to consider technical peculiarities of electricity and avoid imbalances and blackouts. The economic consequences of these rules are a recent subject of research. Several studies highlighted the inefficiency of these rules and how they can sent incorrect incentives to market players (Glachant and Saguan, 2007; Scherer et al., 2015; Vandezande, 2011). Several countries have then changed or are changing rules of their real-time market based on more economic grounds. For instance, the French TSO decided recently to implement an ISP close to a single price instead of the previous dual price to send better incentives to market players (RTE, 2018).

Secondly, another important trend regarding the design of balancing and security models lies in the massive impact of intermittent renewable technologies for several years. While forecast methods are improving, several studies show that this development requires (and will require) an increasing need for balancing and for reserves procurement (Aigner et al., 2012; Holttinen et al., 2011). More precisely, the increasing need for flexibility, i.e. for capacities which are able to react quickly to compensate wind or PV forecast errors, is highlighted (Huber et al., 2014). Balancing market should then be able to respond to these increasing imbalances at least cost for the society. This emphasizes the need for better rules to reduce the costs of balancing (for instance, incentives sent to wind producers to improve their forecast) but also to better reflect the real cost of balancing. This last point is important since it provides incentives to deliver flexibility and invest in the needed technologies (for instance, storage utilities). Several studies assess how market design of real time should evolve to better incentivize flexibility provision and to integrate renewable at least cost (IRENA, 2017; Vandezande et al., 2010; Wärtsilä, 2014).

Finally, the will to create a common power market across Europe results in several discussions about integration and harmonization of balancing markets for some years. This unique market should enable to maximize social welfare by using the cheapest power plants to produce, wherever they are in Europe (subject to network constraints), and by serving consumers with the highest willingness to pay, regardless of their location. It should also increase the reliability of power systems by mutualizing reserves and solutions to solve imbalances. However, the creation of a unique market requires sufficient harmonization of the different rules of national markets (Glachant and Lévêque, 2009). While integration and harmonization focused on day-ahead and intraday markets in the previous years, integration of balancing market is currently discussed in Europe, in particular with the adoption of the Network Code on Electricity Balancing by ENTSO-E in 2017. In particular, it highlights a set of rules to define ISP, the need for standardization of balancing products across Europe and for a clear separation between intraday markets and activations of reserves for balancing by TSOs (European Commission, 2017). Several studies assessed the benefits of this integration (Fournié et al., 2016; Mott MacDonald, 2013) (for instance, thanks to a regional procurement of reserves or the sharing of balancing bids) but also the minimum harmonization which is needed for the success of this integration, in particular in the context of different strategies of balancing and security models in Europe (Esterl et al., 2016; Pentalateral Energy Forum, 2016; Van De Veen et al., 2010; Vandezande, 2011).

1.3.2. The increasing interest for balancing and security models results in several economic studies of the best market design to implement

The recent interest for the market design of balancing and security models results in abundant literature regarding the best market design to implement in function of different criteria, such as the security of the system or the economic efficiency. Market power is also an important criterion to consider given it is likely in these markets at a very short notice. For instance, van der Veen and Hakvoort (2016) identified the relevant design variables and performance criteria that play a role for European balancing markets. They found that a trade-off may be necessary between the different criteria and that balancing market design could be a substantial challenge. More precisely, several other studies advised for a specific design to implement. Three main area of research can be identified and are briefly introduced thereafter.

Firstly, the design of the ISP has been investigated. For instance, the choice between a marginal pricing or an average pricing or between a single or dual ISP has been studied by several authors (Hirth and Ziegenhagen, 2015; Littlechild, 2007; van der Veen et al., 2018): the solution of a single marginal pricing is more cost reflective and leads to more efficient allocation of resources. According to Vandezande et al. (2010), this imbalance price should consider both the price of activation (i.e. the energy) but also the price of reserves procurement (i.e. the capacity).

Secondly, the design of the reserves procurement market has also been explored. For instance, the scoring rules (between the capacity and energy bids) were studied by Müsgens et al. (2014) and Chao and Wilson (2002). Kahn et al. (2001) argued the superiority of a uniform pricing over a pay-as-bid pricing. Müsgens et al. (2014) suggested a price elastic procurement of reserves: when procurement is cheap, the TSO could buy more reserves to increase reliability and vice versa. Co-optimization of reserves and energy for power exchanges is also discussed to increase efficiency (Oggioni et al., 2016; Sőrés et al., 2014). The length of contracts for reserves procurement was also considered (Böttger and Bruckner, 2015; Just, 2011; Müsgens et al., 2014). Finally, the conditions to enable the participation of new technologies, such renewables or Electric Vehicles, have been studied (Borne et al., 2018).

Thirdly, the design of the activation of reserves in case of imbalances was also studied. For instance, the use of pro-rata or merit-order activation rules was investigated by E-Bridge Consulting Gmbh and Institute of Power Systems and Power Economics (2015) and Avramiotis-Falireas et al. (2014). Similarly to the reserves procurement, the choice between pay-as-bid or marginal pricing was discussed. Hirth and Ziegenhagen (2015) studied the conditions to provide balancing bids with renewable technologies. A last example of current studies is the need to increase the participation of market players to help balancing, either thanks to passive balancing (Hirth and Ziegenhagen, 2015; TenneT et al., 2011), i.e. market players can be imbalanced in real time if their imbalances help the system being balanced (as it is currently implemented in the Netherlands), or thanks to a shorter gate closure of intraday markets (Barth et al., 2008; Holttinen et al., 2016; Müsgens and Neuhoff, 2006). In this latter case, market players can react more quickly to imbalances. This is especially true for wind producers which can better manage forecast errors thanks to intraday markets close to real time.

1.3.3. However, the general design of security models and the characteristics of the French one were never studied in the current literature

In the current academic literature, few studies focus on the comparison between the different strategies and principles of security models introduced in the previous section. Literature tends to study the specific details of market design (but which are nevertheless essential, like the design of reserves procurement market) while taking as granted the general philosophy of the security model implemented in the country. In particular, to the knowledge of the author, the concept of the margin approach implemented in France was never mentioned in the economic literature. The comparison with the reserves approach in terms of efficiency are then unknown. In particular, the impacts and costs of the activations to ensure system margin were never studied.

The margin approach is the main characteristic of the French balancing mechanism compared to other European countries. There is a need to understand its economic properties and to study whether the French TSO should change its philosophy by adopting a reserves approach. In particular, the French regulator has asked the French TSO to perform a quantitative analysis to study the costs or benefits that would bring a transition to a security model based on a reserves approach (CRE 2017). This comparison is essential to reach a better efficiency of the balancing activities while ensuring the security of the system, a topic which was at some point overlooked at the beginning of market reforms. In France, costs associated with the reserves procurement are more than € 250 million a year (CRE, 2016). The study and comparisons of security models is then relevant regarding amounts at stake.

Based on the current literature, the economic advantages or disadvantages of this transition cannot be answered since the French security model has never been studied. Even if the literature studied the impact of reserves procurement on the generation costs, in particular how a larger upward reserves procurement tends to increase generation costs[15] (de Vos and Driesen, 2012; Hummon et al., 2013; Müsgens et al., 2014), the

[15] In a simplified way, the higher volume of upward reserves is either provided by baseload plants or by mid-merit/peak plants. In the first situation, baseload plants have to reduce their production to provide upward reserves: more expensive plants have to produce instead. In the second situation, mid-merit or peak plants have to be started up to be able to react quickly if the TSO requires the activation of the procured

impact and the costs of activations to ensure system margin is unknown and thus the comparison is limited. Moreover, the costs or benefits of both security models can hardly be computed based on a comparison of current costs in France and in countries with a reserves approach (like the Netherlands or Germany). Indeed, several other characteristics are different between these countries (for instance, the generation fleet, the obligation to provide available capacities to the TSO in France, the proactive approach in France vs. the reactive approach in the Netherlands…) and differences (of generation costs, of prices…) between these countries cannot be explained by the difference in security model only. Consequently, the current literature does enable to compare the two types of security models for the French power system. This part of the thesis aims at filling this gap by studying the following research questions:

- What would be quantitatively the impacts of a transition to a reserves approach, instead of the current margin approach, for the French power system?
- In particular, what are the differences between the costs incurred by a higher level of reserves procurement in the reserves approach and the costs due to activations to ensure system margin in the margin approach?
- Moreover, how do both security models influence the power system, notably the different prices (for example, the reserves prices, the day-ahead price or the ISP) and the decisions of market players?

To answer these research questions, a modelling of both security models applied to the French power system is developed. Resorting to modelling appears essential to compare quantitatively both security models. First, even if the current literature shows that a larger upward reserve procurement (as it is the case for the reserves approach) tends to increase the generation costs, the range of this increase is difficult to compute without modelling. Indeed, it depends on the actual plants that provide the reserves. These plants may vary depending on the studied day (for instance during peak or off-peak hours) or on their technical constraints (for instance, a power plant which is online can provide reserves contrary to an offline one). For the margin approach, costs due to activations to ensure system margin are unknown in the literature. Moreover, their computation is difficult without modelling since they depend on several variables, such as the imbalances of

reserves. Then, these expensive plants have to produce at least at their minimum output, which can force cheaper plants to reduce their production.

market players (and then their forecast of the electricity consumption) or their previous generation decisions. Finally, besides the comparison of costs between both security models, it is also relevant to study and compare how both security models impact the decisions of market players, and in particular the incentives sent to help balancing the system in real time. This comparison seems difficult without modelling and without computing the imbalance settlement prices. For all these reasons, a modelling seems necessary to answer the research questions. This modelling uses an agent-based approach, as explained in the beginning of the chapter 2. This chapter also develops the main assumptions made to build the modelling. Input parameters, close to the French power system, are described in chapter 3. Finally, results and comparison between both security models are presented in chapter 4.

Chapter 2. Presentation of the modelling

Résumé du chapitre 2 en français :

Ce deuxième chapitre présente la modélisation développée pour répondre à la question de recherche. Le recours à une modélisation apparaît indispensable afin de considérer précisément le fonctionnement des deux modèles de sûreté, de quantifier leurs performances et de comprendre leurs impacts sur les différents marchés (sur les prix par exemple) et sur les décisions des acteurs. Pour étudier les effets des modèles de sûreté (notamment les impacts d'une contractualisation plus forte de réserves dans le modèle alternatif) et afin de considérer convenablement les marges disponibles dans le modèle français, les marchés et mécanismes de court terme doivent être considérés et modélisés dans leur ensemble, à savoir :

- Le marché de contractualisation des réserves car les réserves sont au cœur du modèle de sûreté,
- Le marché J-1 afin d'étudier les décisions de production et de démarrage des centrales,
- Les marchés infra journaliers afin de résoudre les éventuels écarts des acteurs suite au marché J-1 ou suite à une nouvelle estimation de la consommation,
- Le mécanisme d'études des marges et d'activation pour cause marge qui est au cœur du modèle de sûreté français,
- Le mécanisme d'ajustement qui permet en partie de juger de l'efficacité de la contractualisation des réserves ou de la gestion des marges.

Une étape additionnelle, le *rescheduling* des acteurs, est également modélisée. Elle permet aux acteurs de décider du schéma de production optimale de leurs centrales en fonction des résultats du marché J-1 et des contractualisations des réserves. De plus, une attention particulière est portée à la prise en compte des contraintes techniques des centrales (notamment les contraintes de démarrage) étant donné leur importance dans l'étude des marges dans le modèle de sûreté français.

La modélisation de l'ensemble de ces marchés est faite avec une approche *Agent Based*. Cette approche permet de modéliser le comportement des acteurs de façon décentralisée, leurs prises de décisions dans un environnement complexe (e.g. information imparfaite) et les interactions entre eux. Par ailleurs, une approche *Agent Based* présente l'avantage d'être mieux adaptée pour représenter un tel séquencement de multiples marchés tout en considérant les contraintes techniques des centrales et les écarts des acteurs au sein de leur portefeuille, ce qui n'est pas aisé avec une approche optimisation ou équilibre. En particulier, deux agents différents sont considérés :

- Le GRT, dont le but principal est de gérer la sûreté du système (via la contractualisation de réserves et la gestion des marges),
- Les Responsables d'Equilibre (RE), qui possèdent un parc de production dont ils cherchent à maximiser le profit et/ou un portefeuille de clients dont ils doivent satisfaire la demande.

Dans ce chapitre, la modélisation des différents marchés et mécanismes considérés et du comportement des acteurs est présentée. En particulier, les différentes hypothèses nécessaires pour simplifier le problème sont exposées.

This chapter presents the modelling developed and used to answer the research questions. In a first section, the choice of the type of approach to consider is studied. Then, a general overview of the modelling is made. Finally, in a last section, the modelling of each market and mechanism and the different assumptions are presented.

2.1. A modelling based on an agent-based approach

The first step in the modelling development is to choose the type of approach to consider among the three classic ones mentioned in the literature, namely the optimization, equilibrium and simulation approaches (Ventosa et al., 2005). This is introduced in the first following section. Moreover, the modelling of the precise day-ahead market and the related bidding strategy should be investigated in more details when non-convex technical constraints such as start-up costs are considered: this point is studied in a second step.

2.1.1. The complexity of the modelling to assess properly the characteristics and impacts of both security models requires using an agent-based approach

To choose the type of approach to consider, it is necessary to list the most important points to be taken into account when studying both security models, and in particular when studying available margins which presents the strongest innovation (and therefore modelling uncertainty) compared to the existing literature. The available margins computed in the French security model, and then the need for activation to ensure system margin, are the consequences of market players' decisions on the generation schedule of their power plants and then the results of several interactions between market players and short-term markets. In particular, two main parameters strongly influence the total available margin of a system, namely[16]:

- The available margin of each power plant, which highly depends on its technical constraints and the start-up and production decisions previously made by market players.

[16] The precise calculation of available margin will be presented in the modelling chapter.

- The total imbalance of the system, resulting from the individual imbalances of each market player.

Regarding the first point, the available upward margin for each plant is not always equal to the difference between how much it plans to produce and its maximum output. Its technical characteristics and the fact of being online or offline must be considered when assessing the available margin (see figure 5 and figure 6). For example, a power plant which is offline may not be able to provide available upward margin if it cannot start up quickly enough. Similarly, an online power plant may provide a low upward margin if its ramping abilities are small.

The available margin also depends on the aggregated system imbalances that the TSO anticipates. Indeed, the required margin is calculated by assuming that market players are correctly balanced: this margin enables to face only the imbalances that may occur between the time when computations are made and the real time. If the TSO anticipates that market players will be negatively-imbalanced in real time, it will need a higher available upward margin. Part of this margin is needed to solve anticipated imbalances of market players and the remaining margin is needed to ensure that the system can cope with possible imbalances that may happen before the real time. A similar reasoning applies if the system is positively imbalanced.

Therefore, further precautions should be taken into account when modelling:

- The technical constraints of power plants (particularly their start-up constraints) and their consideration in the decisions and strategies of the market players. In particular, the way they are considered on the day-ahead market is important since results of this market strongly influence the production decisions of market players.
- The imbalances of market players and the solutions with which they can limit and solve them. These imbalances can result from forecast errors but also from differences between what market players sold on the energy markets and what they actually produce (which can differ due to technical constraints). Solutions such as intraday markets may enable market players to reduce these imbalances.

Thus, in order to properly study both security models (in particular the margin approach) and their effects on short-term markets, many markets and mechanisms need to be modelled, namely:

- The reserves procurement markets: procurement of reserves are at the centre of both security models and the procurement level distinguishes the reserves and margin approaches
- The day-ahead market, which is essential to determine power plant production level and start-up decisions. In particular, technical constraints should be considered within this market to avoid selling energy which would be impossible to produce due to these constraints.
- Intraday markets, which can be necessary to solve any imbalances of market players resulting from new consumption forecasts or differences between the energy sold on the day-ahead market and the energy power plants can actually produce considering their technical constraints.
- The mechanism to study the required and available margins and the need for activations to ensure system margin, which is essential for the margin approach.
- The balancing mechanism, which enables to assess the effectiveness of the reserves procurement or the management of margins and to study the impact of both security models on the imbalance settlement prices.

These different points strongly influence the modelling approach to be considered. In particular, among the three main approaches mentioned in the literature, namely the optimization, equilibrium and simulation approaches, the first two ones do not seem relevant to study this complex modelling. Indeed, with an optimization approach, a unique market player is often considered which owns all plants and which can make optimal decisions regarding their generation schedule. These decisions are then likely to differ from decisions made by decentralized market players, which are not necessarily optimal in particular when non-convex technical constraints are considered (such as the start-up constraints or the minimum up and down time constraints). Then, computation of available margin (and the need for activations to ensure system margin) is likely to be different with this optimization approach. Even if the equilibrium approach enables to consider several decentralized producers and their optimal production decisions, this approach can be difficult to implement when several sequential markets and mechanisms are considered as it is the case in this chapter[17]. Indeed, the formulation of the objective function can be difficult when considering multiple markets and the interactions between them. In the literature, an equilibrium approach is often limited to the study of two consecutives markets through a two-stage model. For instance, Khalfallah and Rious (2013) study the forward market and the real-time market. Xiao et al. (2016) model a two-stage electricity market considering the day-ahead market and a rescheduling stage where producers try to fulfil their day-ahead commitment. Moreover, considering the non-convex technical constraints within this approach can be complex and is often ignored with an equilibrium approach. This non-consideration greatly simplifies the bidding strategy of market players but is not suitable for the aim of this modelling. Although the use of the optimization or equilibrium approaches does not seem impossible per se to study the security models, their practical implementation seems very difficult regarding the existing literature (Maenhoudt and Deconinck, 2010; Sensfuß, 2007; Weidlich and Veit, 2008).

On the contrary, the use of a simulation approach appears to be more suitable to this study and to model the complex short-term sequence of markets and mechanisms considering technical constraints. In particular, the chosen approach in this chapter is close to an agent-based approach which has already been used extensively in the literature to study complex power system with multiple sequential markets and to compare different market designs (e.g. OPTIMATE project[18] or the PowerACE modelling[19]). Although an agent-based approach does not necessarily enable to study a system with an economic equilibrium or a system for which social welfare is maximized, it offers greater flexibility for the modelling and seems much easier to implement. However, it should be noted that, even with this approach, the modelling remains complex and requires the use of several simplifying assumptions.

[17] This point is also true for the optimization approach.
[18] http://www.optimate-platform.eu/index.html
[19] http://www.gsdp.eu/uploads/tx_conturttnews/Philipp_Ringler_-_PowerACE_-_Agent-Based_Simulation_of_Electricity_Markets.pdf

2.1.2. The specific modelling of the day-ahead market when considering non-convex technical constraints

Once the general approach of an agent-based model is chosen for the entire modelling, the modelling of the precise day-ahead market should be investigated. Indeed, this market is essential for power systems as it provides a reference price for energy and greatly influences decisions made by market players regarding the generation schedule of their plants (for instance, the production level or the start-up or shutdown decisions) and then the margin study. A particular attention should be paid to this modelling when technical constraints, and in particular non-convex technical constraints, are considered. Moreover, this specific modelling of the day-ahead market should consider the specific organization of current European (and French) day-ahead markets built around a power-exchange (PX), contrary to the US approach organized around a centralized power pool (Meeus and Belmans, 2007) [20].

A qualitative comparison of advantages and drawbacks of four different approaches to model the short-term PX-based market is then performed[21]. These approaches are considered based on the available literature and are described more precisely in appendix A. Moreover, they are assessed according to two criteria: their relevance for the PX-based market like the French one and their complexity to implement and run. The table 3 below presents the results of this qualitative evaluation. More details can be found in appendix A.

[20] This distinction is particularly relevant when considering non-convex constraints since both organizations may result in different outcomes (prices, production decisions…). On the contrary, when non-convex constraints are disregarded and under certain assumptions (e.g. perfect information), a power-exchange and a centralized power pool can lead to the same results regarding the commitment decisions and the electricity price (Caramanis, 1982).

[21] To the knowledge of the author, such a comparison in the context of a PX is missing in the literature.

Table 3: Quantitative comparison of four different approaches to model the short-term PX-based market

+ : good ; 0 : medium ; - : weak	Centralized UCM	Convex UCM	Decentralized model with simple bids only	Decentralized model with complex bids
Criterion 1: Is the model relevant for a European market with a PX?				
Consideration of technical constraints as the market players do (or can do) in European markets with a PX	-	-	**0**	+
Relevance of computed prices regarding the possible prices experienced in European markets with a PX	-	**0**	**0**	+
Consideration of the characteristics of market players' behaviour	-	-	+	+
Criterion 2: Is the model complex to implement ?				
Computation time	**0**	+	**0**	-
Complexity of the problem formulation	+	**0**/+	**0**	-
Existing experience feedbacks	+	**0**	**0**	-
Complexity of the price computation	-	+	+	-

From these results, a trade-off exists between the relevance of the model for the European PXs and the complexity to implement it. Considering a centralized UCM, which is traditionally used to model power pool organization, could lead to high differences in outcomes since non-convex technical constraints are considered explicitly with this approach and then the accepted bids of this market are always technically feasible. Moreover, the defined price is far from the observed price in PX in Europe: for instance, the existence of a side payment to price non-convexity is not relevant for the modelling of the French system and can modify market players' decisions on other markets (e.g. in the reserve procurement market). Moreover, the decentralized model with complex bids (which tries to model the bidding strategy of market players in a liberalized market with a PX using complex bids like block bids) is likely to be more realistic but very difficult to implement. Since the study of both security models already requires the modelling of five markets or mechanisms, the complexity and the computation time of the sole day-ahead market should remain limited. Thus, a decentralized model with simple bids only seems to be a wiser solution. It enables to have a limited complexity but high enough to formulate a bidding strategy which can consider implicitly the non-convex technical constraints. This solution is then chosen for the modelling of the French power exchange in this chapter. A bidding strategy will be defined considering different price forecasts and the technical constraints of power plants. Market players submit simple bids which will maximize their revenues given uncertainty on the future price forecast and while trying to express the technical constraints of their plants (in particular their start-up costs).

2.2. General overview of the modelling

2.2.1. Markets and mechanisms considered in the modelling

The assessment and comparisons of both security models and their impacts require modelling the following markets and mechanisms:

- The reserves procurement markets
- The day-ahead market
- The intraday markets
- The mechanism to study the need for activations to ensure system margin (only in the margin approach)
- The balancing mechanism

2.2.2. Modelling differences considered to study both security models

Two different organizations of the short-term sequence are modelled and compared in this chapter:

- A short-term organization considering all the markets and mechanisms defined above and whose security is managed with a margin approach
- A short-term organization considering the markets and mechanisms defined above with the exception of the mechanism to study the need for activations to ensure

system margin, and whose security is managed with a reserves approach

For ease of reading and since both organizations only differ according to the implemented security model, the term "French security model" is used to designate the first organization (i.e. whose security is managed thanks to the margin approach) and the term "alternative security model" for the second organization (i.e. whose security is managed thanks to the reserves approach). Thus, in the following sections, when comparison is made between both security models, one should understand that the comparison is performed between the entire short-term organization and all the relevant markets and mechanisms and not just the security model.

Modelling assumptions of the different markets, behaviour of the agents and input data are strictly identical between both models, except for two essential points:

- The level of reserves procurement, since the alternative model requires a greater level of procurement
- Activations to ensure system margin are possible in the French model only

Final differences between both models will thus result only from these two considerations and the impacts they could have on generation decisions.

2.2.3. Agents considered in the modelling

To simplify the modelling, only two types of agents are considered:

- The TSO, whose main purpose is to manage the system's security thanks to the procurement of reserves and the management of margins,
- The Balance Responsible Parties (BRP), which own power plants of which they seek to maximize the profit, and/or a portfolio of customers for whom they have to satisfy their demand.

It should be noted that, throughout the study, electricity demand is considered as inelastic and demand response is not modelled for the sake of simplicity[22]. Thus, agents' decisions

[22] Considering demand-response would not fundamentally change the modelling at first glance. As a first step, this technology could be modelled as a generating asset but with a very high variable cost. Difficulties may arise in the dimensioning of this cost and the amount of demand-response available in the system.

concern their power plants only. Moreover, the learning behaviour of both types of agents is not considered in the modelling given its complexity and the related computation time.

These two types of agents intervene on the markets and mechanisms mentioned above in a different way. BRPs are at the centre of the modelling, since they are the key players of decentralized electricity markets. They decide how their plants should produce and then participate, by formulating bids, in the reserves procurement markets, the day-ahead market, the intraday markets and the balancing mechanism. In this study, BRPs are assumed not to be able to exert any market power. In particular, when formulating bids on the different markets, these agents are considered as price-takers, i.e. their submitted offers do not influence the market price. They do not seek to adopt a strategic behaviour, for example by reducing the offered quantities (strategic withholding) in order to increase their profits. On the day-ahead market, BRPs are considered able to submit bids above their marginal cost of production. Indeed, due to the non-convex technical constraints of power plants (especially their start-up costs), a price strictly equal to their marginal cost cannot withstand a competitive equilibrium (Müsgens, 2005; Scarf, 1994). In particular, this price must reflect the start-up costs and then may be higher than the marginal cost during peak hours, without this being considered an abuse of market power (Abrell et al., 2008; Weigt and Hirschhausen, 2008). A bidding strategy to reflect these non-convex technical constraints will be presented later. In other markets (intraday market and balancing mechanism in particular), bids are made exactly at the marginal cost of production (or the opportunity cost for hydroelectric power plants) since start-up decisions are not considered for this timescale.

The second type of agents considered in the modelling is the TSO. Its role is limited to the management of the system's security. It mainly intervenes to define the demand on the reserves procurement markets. Its role on the balancing mechanism is also slight: although it organizes this mechanism and activates bids, it does not define supply and demand, such variables resulting from BRPs' actions. However, in the French security model, the TSO has a key role for the computation of the available and required margins and the assessment of the need for activations to ensure system margin.

Moreover, for both agents, uncertainties are modelled for the forecast of three variables: the national load level as well as the wind and PV production levels. Forecasts of these variables are carried out twice, once day-ahead and once intraday. Parameters defining the forecast errors are described in the sections 3.1.3 and in 3.2.1.

To conclude, a schematic and simplified representation of the different markets and mechanisms considered in both models, as well as the actions of both agents, is illustrated on figure 9.

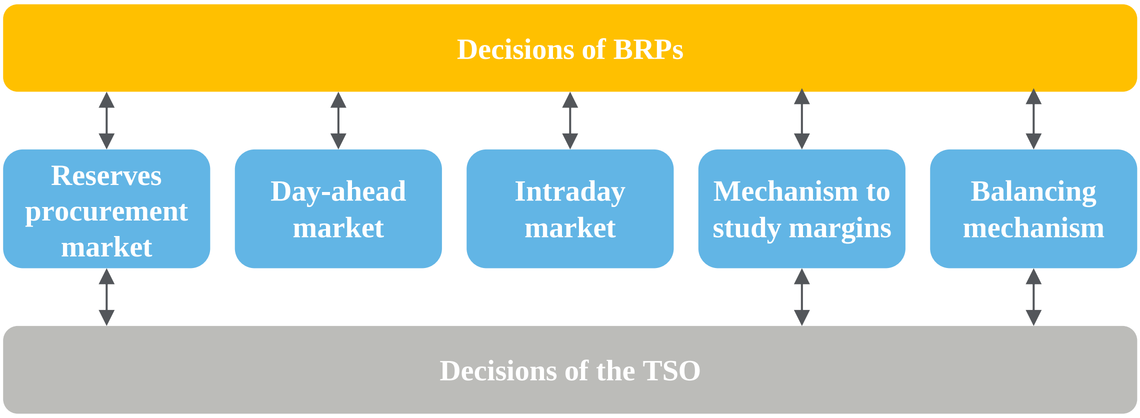

Figure 9: Simplified overview of the modelling

<u>Main assumptions</u>[23]:

- Two types of agents: the TSO and BRPs
- BRPs do not exert any market power and bid competitively to cover as much as possible variable and non-convex costs
- Both agents made imperfect forecasts of the real-time conditions

2.2.4. Time horizon of the simulations and considered time step

Both security models are simulated over a period of one week, with a maximum time step of 30 minutes (i.e. what happens inside this time step is not considered). This one-week horizon results from a trade-off between, on the one hand, the need to consider enough days to correctly measure the impacts of the security model and, on the other hand, the complexity of the modelling (the simulation requires longer computation time for two weeks), the relevant use of input data (some input parameters are considered as constant over the duration of the simulation, which may not be true anymore when considering a longer time horizon) and the difficulty to model hydroelectric plants (over one week, only

[23] At the end of each section, main assumptions considered in the modelling will be summarized.

a short-term arbitrage is considered in the management of the water reservoir which enables to simplify the related modelling, cf. section 2.3.1.2). However, in order to have more significant results, several simulations of one week are carried out for different representative weeks (for winter and summer in particular) and for different forecasts of the residual demand.

<u>Main assumptions</u>:

- Simulation over one week only, with a minimal time step of 30 minutes

2.3. Modelling of both security models

In this section, the different markets and mechanisms considered in the modelling and the associated assumptions are introduced according to three points: 1) the functioning of the market/mechanism and the definition of exchanged products, 2) the actions of the TSO on this market/mechanism and 3) the actions of BRPs. Assumptions about the modelling of power plants are also introduced. These assumptions are made according to their relevance for the French power system while also considering the associated complexity and computation time. Moreover, some hypotheses are supported by discussions the author had with the French TSO and its feedback on the current functioning of the French power system.

2.3.1. Modelling of power plants

Before explaining the modelling of the different markets and mechanisms, the modelling of power plants is introduced. Two types of plants are distinguished here: dispatchable generation and non-dispatchable generation.

Non-dispatchable generation gathers technologies for which BRPs are assumed not to be able to control their production level. They are mostly intermittent technologies, such as wind or photovoltaic. BRPs consider generation of these technologies by subtracting it from the consumption of their portfolio (i.e. they consider the residual demand of their portfolio). In particular, these technologies cannot provide reserves and they do not offer any available margin to the system.

The dispatchable generation assets relate to power plants for which BRPs can control the generation level and the commitment decisions. They can be thermal units (nuclear, coal...) or hydroelectric plants. They are at the centre of the modelling, notably for the construction of bids submitted by BPRs in the different markets and for the computation of margins. Thus, further precautions should be paid to their modelling and the consideration of their technical constraints which appear essential for the computation of available margins. The modelling of dispatchable thermal and hydroelectric power stations is presented below.

2.3.1.1. Modelling of the thermal dispatchable power plants

BRPs construct their offers in the different markets and make their production and start-up/shutdown decisions using Unit Commitment Models (UCM) (Van den Bergh et al., 2014). This tool enables them to maximize their profit (or minimize their costs) while explicitly considering the technical constraints of their plants. It ensures that the final generation schedules decided by BRPs comply with the technical constraints, which is essential to ensure the correct functioning of the power system. The technical constraints of the dispatchable thermal power plants considered in the UCMs of the modelling are:

- The maximum output constraint: a plant cannot produce beyond a certain level
- The minimum output constraint: a power plant cannot produce below a certain level, except if it is offline
- The start-up and shutdown constraints: a plant cannot start up and shut down instantaneously
- The ramping constraints: the variation of production between two time steps is limited
- The minimum up time (respectively down time): once started up (resp. shut down), a power plant must remain online (resp. offline) a minimum number of hours before it can be shut down (resp. started up).

In addition, two types of costs are considered for these plants:

- The variable production costs (proportional to the produced quantity)
- The start-up costs (which are born each time the plant starts up)

Moreover, when performing these UCMs, a two-day horizon is considered to study the profits and costs of thermal power plants. Even if only the results of the first day are considered[24], a second day is added to avoid edge effects. For example, by considering a one-day UCM, it is unlikely that a BRP decides to start up a plant at the end of the first day because it is not able to capture any profits the plant may made on the second day. When considering a two-day UCM, the edge effects are still present but limited to the second day of the UCM whose results are not considered to compute bids and make production decisions. This UCM is defined as the thermal UCM.

Modification of the considered technical constraints for nuclear power plants

The start-up and shutdown decisions of nuclear plants pursue a logic that the modelling cannot take into account. Indeed, with the proposed UCM, start-up or shutdown decisions are made by considering two days of profits only. This short-term horizon does not seem to be consistent with a baseload use of nuclear power plants which would require a forecast of profits over a longer horizon. Moreover, in France, start-up and shutdown decisions for nuclear plants are based on refuelling or maintenance constraints more than on a short-term profit assessment. Since the simulations carried out in this study only cover one week, it seems irrelevant to consider the start-up and shutdown decisions of nuclear plants for such a low time horizon. The number of online nuclear power plants will probably be constant over this one-week period. Thus, it is decided not to consider the start-up and shutdown decisions of nuclear power plants in this modelling. They are either already online or offline at the beginning of the simulation (the distribution between these two states is done thanks to the historical availability of nuclear plants, see section 3.1.1.2) and they cannot change their state during the simulation. For these power plants, only the maximum, minimum and ramping constraints as well as the variable production costs are considered in the UCM.

2.3.1.2. Modelling of the hydroelectric dispatchable power plants

Due to the large number of hydroelectric plants in France and the difficulty to get their technical characteristics (particularly the size of their water reservoir or their maximum output), hydroelectric power stations of each considered BRP are gathered and modelled as one equivalent plant. In addition, because of the complexity of their modelling, pumped-storage facilities are not explicitly considered.

[24] In particular, bids and productions decisions are built on a daily basis. For example, a BRP will compute the bids it will submit on the day-ahead market for all the hours of the next day, and only for those hours.

Thanks to the high flexibility of the hydropower plants, it seems relevant not to consider their start-up and shutdown constraints, their ramping constraints and their minimum output constraint; only the maximum output constraint is kept. Moreover, no variable costs are considered. It should be noticed that the absence of variable costs does not mean that BRPs can use these plants as they wish. Indeed, a reservoir constraint is added for each equivalent hydroelectric plant. At the beginning of the simulation, this plant has a limited volume of stored water which is not sufficient to produce at its maximum output during the whole simulated week. The BRP has to perform a trade-off and limit the use of its plant to the most valuable hours. A water value is thus given to the stored water, reflecting in some way a variable production cost. Moreover, no inflows are considered to simplify the problem.

Thanks to the maximum production and reservoir constraints, a "hydraulic" UCM (opposed to the previous UCM for thermal plants) can be formulated in order to find the optimal production schedule of hydroelectric plants. This UCM is performed on a moving time horizon with an initial water stock to properly consider the reservoir constraint and considers up to two weeks of profits to avoid edge effects[25]. Data for the maximum output and reservoir constraint for the equivalent hydroelectric plant of each BRP is presented in the section 3.1.2.

<u>Main assumptions</u>:

- Non-dispatchable plants are considered as a reduction of the consumption: BRPs cannot control their generation level.
- For thermal dispatchable plants, BRPs mainly compute their bids and the final generation schedule based on a UCM which considers technical constraints of plants, as well as the start-up costs. This UCM is performed over a two-day horizon.
- For nuclear plants, the start-up and shutdown decisions are not considered in the UCM.

[25] For the first day of the simulation, the hydraulic UCM is run with an initial level of reservoir which has to be used over two weeks. For the second day of the simulation, the level of the reservoir has decreased (since the plant has produced during the first day) and the hydraulic UCM computes the optimal use of the water over the remaining time horizon, namely two weeks minus on day.

- For hydroelectric plants, only one equivalent plant is assumed per BRP. Its generation schedule is also studied based on a UCM for which technical constraints, except the maximum one, are not considered.
- A reservoir constraint is also added for the study of hydroelectric plants. The associated UCM is solved considering a moving time horizon up to two weeks.

2.3.2. Reserves procurement markets

As it will be explained in the section 3.3.1, the implementation of the alternative security model in the French power system would only impact the procurement level for Replacement Reserves, both upward and downward. The procurement levels of FCR, aFRR and mFRR, both upward and downward, would remain the same between both security models for the French power system. For this reason, the aforementioned reserves are not considered in the modelling, as both models should not be very different regarding their provision. Only the procurement and the provision of RR are modelled. This assumption enables to decrease the complexity of defining the technical constraints of UCMs and to decrease the computation time.

To ensure the availability of the reserves in real time, the TSO procures them thanks to a market: BRPs whose bids have been accepted in this market must then provide reserves in real time to the TSO. Moreover, procurements of the different types of reserves occur successively, i.e. BRPs formulate their bids for a first type of reserve, then the market is solved, BRPs compute their bids for the second market of reserves considering the results of the first one and then the second market is solved, etc. In particular, it is assumed that the procurement is made for upward RR first and then for downward RR. In the following sections, the modelling of these procurement markets is introduced.

2.3.2.1. Functioning of the market and definition of the exchanged products

Two different reserves products are studied and procured:

- the upward RR, which can be activated in 30 minutes,
- the downward RR, which can be activated in 30 minutes.

These products are procured successively and in that order. Moreover, asymmetric products are considered (i.e. there is one upward product and one downward product) since procurement volumes may be different in both directions. Daily products are considered, i.e. there is a procurement market, and then a procurement price, for each day; this market procures reserves for all hours of the next day. Since daily products are considered, the reserves procurement is assumed to take place just before the clearing of the day-ahead market and the day-ahead price is therefore unknown at that time.

In the modelling, all dispatchable technologies are assumed to be able to participate to the procurement market within the limits of their technical constraints (in particular their ramping constraints). Finally, it should be noted that the procurement is performed on a portfolio basis and not on a power plant basis. In other words, a BRP does not formulate a bid for each of its plants but only one for its entire portfolio. Thus, the obligation imposed on BRPs which had accepted bids on the reserves procurement markets does not force them to provide reserves in real time with a particular plant (in particular the one they had considered at the time of procurement): they remain free to choose which power plants will provide the reserves in real time (notably according to the results of the energy markets), as long as the total level of provided reserves over the whole portfolio is equal to the volume accepted for the BRP on the reserves market[26].

2.3.2.2. Actions of the TSO

The TSO intervenes on these markets by defining the amount of reserves to be procured (see section 3.3.1). Moreover, this demand is considered as inelastic.

2.3.2.3. Actions of BRPs

BRPs participate to the reserves procurement markets by submitting bids. Only BRPs with dispatchable power plants (thermal or hydroelectric ones) are considered in this section. In order to construct their bids, BRPs compute the costs of providing these reserves. These costs are based on the opportunity costs associated with the procurement obligation, i.e. the profits they forsake or the costs they incur by providing reserves with their power plants (Hirth and Ziegenhagen, 2015; Xiao et al., 2016). In particular, activations costs, i.e. costs incurred when reserves are actually activated by the TSO in

[26] However, BRPs must provide the exact level of reserves they commit to provide (a penalty in case they do not provide enough reserves is not considered).

real time, are not considered by BRPs in their bids at that time[27]. It is then necessary to estimate the profits the BRP would realize without and with procurement, and thus to anticipate its decisions on the different markets to come (for example, the quantity that the BRP will provide in the other reserves market, the amount of energy that it will sell on the day-ahead market or on the intraday markets, etc.). These decisions are closely linked and a trade-off between them is necessary. To simplify the problem, the study of opportunity costs is limited to an arbitrage with the day-ahead market only. This seems to be the most relevant choice given the importance of this market for power plants.

<u>What is the estimated profit of the portfolio on the day-ahead market (with and without procurement)?</u>

To calculate the estimated profit of their portfolio on the day-ahead market, BRPs consider several day-ahead price scenarios (see section 3.5 for more details on these price scenarios). Using several price scenarios enables to consider the uncertainty that BRPs may face since day-ahead prices are unknown at the procurement time. Based on these scenarios, BRPs aim at maximizing the profit of their generation portfolio (hydroelectric and thermal plants) by valuing their production at these estimated day-ahead prices while considering the technical constraints of their power plants using UCMs. BRPs are then assumed to be price taker. Besides, BRPs have also to compute the expected profit of their generation fleet when some plants provide reserves: constraints must then be added to the UCM to ensure that these plants can technically provide reserves in real time if needed, namely:

- The modification of the maximum and minimum outputs: if a plant is identified to provide upward reserves, it cannot produce at its maximum power since it must keep at least the volume of procured capacities available for the TSO in real time. Similarly, for downward products, the plant must produce above its minimum power output plus the contracted quantity of reserves to be able to provide this level in real time.
- The modification of the ramping constraints (only for thermal plants since no ramping constraints are assumed for hydroelectric plants): between two time steps, power plants cannot modify their production to the maximum of their

[27] Indeed, it is assumed that the TSO selects bids which will provide reserves only based on their capacity costs, regardless of their activation costs.

technical possibility because they must keep some ramping ability available if the TSO activates these reserves in real time.

To simplify the determination of the ramping constraints for thermal plants and reduce the computation time[28], it is assumed that the TSO is not allowed to activate a given power plants for reserves in opposite directions (upwards and downwards) over two consecutive time steps. For instance, the TSO cannot activate a power plant upwards and then downwards on the next time step: it should leave at least one time step between these activations, as shown in figure 10. This assumption is assumed not to have a significant impact on results since different types of plants usually provide upward and downward reserves (upward reserves are mainly provided by mid-merit plants whereas baseload plants often provide most downward reserves). Finally, this assumption is not necessary for hydroelectric plants since no ramping constraints are considered for them.

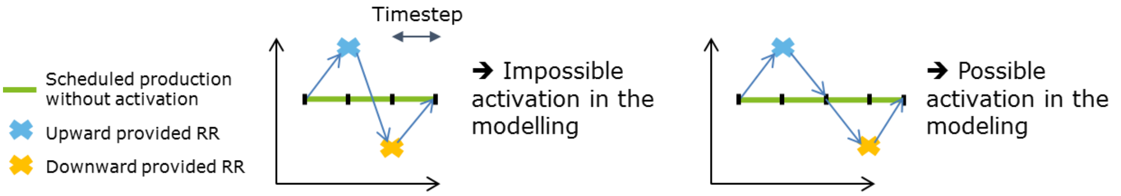

Figure 10: Assumption about activations of reserves in opposite directions over two consecutive time steps

[28] The ramping constraints are considered not only for the procurement stage but also every time a UCM is performed to study the functioning of power plants (for instance, to compute bids on the day-ahead market or on the intraday market). Particular attention must therefore be paid to the computation time.

Each BRP then solves the following optimization problem for its whole generation portfolio for each day of procurement[29,30]:

$$Max\ Profit = \sum_{\substack{thermal\ plants\\ of\ the\ BRP}} \sum_{2\ days} [Q_{th} * \widehat{P_{DA}} - C(Q_{th})] + \sum_{\substack{hydro\ plants\\ of\ the\ BRP}} \sum_{\substack{Up\ to\\ 2\ weeks}} Q_{hy} * \widehat{P_{DA}}$$

$$Under\ the\ technical\ constraints\ of\ thermal\ power\ plants$$

$$Under\ the\ constraints\ of\ the\ water\ reservoir$$

$$Under\ the\ technical\ constraints\ of\ plants\ identified\ to\ provide\ reserves$$
$$(plants\ identified\ to\ provide\ reserves = variables\ of\ the\ UCM)$$

$With$: Q_{th} $(resp.\ Q_{hy})$ $the\ optimal\ production\ of\ the\ thermal\ (resp.\ hydro)\ plant$

$\widehat{P_{DA}}$ $the\ estimated\ day - ahead\ price$

$C(Q_{th}(h))$ $the\ production\ costs\ of\ the\ thermal\ plant\ (variable\ cost + startup\ costs\ if\ any)$

Computation of the opportunity cost

Once the constraints for the provision of RR products are defined, it is possible to calculate the expected profit of the portfolio without procurement and with different volumes of provided RR thanks to the resolution of the UCM[31]. The opportunity cost can be computed as the profit difference with the no-procurement case. Since the optimization problem with procurement is necessarily more constrained than the optimization without procurement, the opportunity cost is positive or at best equal to zero.

[29] It should be noted that a unique stochastic optimization problem is solved considering all price scenarios (each scenario is assumed to have the same probability to occur). Indeed, as the real day-ahead price is unknown at this time, BRPs have to ensure that the plants they identify to provide reserves are able to do it whatever the real day-ahead price, in particular if the lowest or highest price scenario occur.

[30] When studying the estimated profit of the portfolio for the downward RR, the upward RR procurement has already occurred. Each BRP knows the results of this market and then the level of reserves it has to provide within its portfolio. In particular, if the BRP was accepted to provide some upward RR, it must consider this in the UCM by adding a new constraint when computing its opportunity costs to provide downward RR.

[31] Since this optimization problem is not linear (because of the non-convexity of some technical constraints), the profit of the portfolio should be studied for different volumes of reserves. For example, the profit when providing 100 MW of reserves is computed as well as the profit associated with the provision of 200 MW (the opportunity cost is not necessarily two times higher).

Construction of BRPs' bids

Once opportunity costs are studied, BPRs construct a bidding curve they submit on the procurement market[32]. The curves of each BRP are then aggregated and confronted with the inelastic demand formulated by the TSO. The interception of both curves defines the clearing of the procurement market and the amount of reserves that each BRP will have to provide in real time.

Main assumptions:

- Only RR products (upward and downward) are considered.
- Reserves procurement markets are assumed to take place every day and before the day-ahead market.
- Daily and asymmetric products are traded.
- Reserves procurement markets are solved successively, beginning with the upward RR.
- Bids submitted by BRPs are computed based on the opportunity cost to provide reserves which are estimated exclusively based on a trade-off with the day-ahead market.
- Bids are made on a portfolio basis.
- To decrease the complexity of constraints regarding the provision of RR, it is assumed, for thermal plants only, that the TSO is not allowed to activate reserves of a given plant in opposite directions (upwards and downwards) over two consecutive time steps.

[32] For example, if the opportunity cost to provide 100 MW of reserves is 100€, the BPR will bid at a price of 1€/MW for a quantity from 0 to 100 MW. If this cost increases to 400 € for the provision of 150 MW, the second "step" of the supply curve will be 6 €/MW (= (400-100)/(150-100)) for a volume from 100 to 150 MW. Due to the non-convexity of the problem, these costs may not be increasing with the proposed quantity, resulting in a decreasing supply curve. For example, if a plant has to start up to provide reserves, the cost per MW is lower if a large volume of reserves is offered since the start-up cost will be spread over a larger volume. In this case, an additional stage is added to correct this (by modifying submitted bids so that the new bid is necessarily higher or equal than then previous one) and make sure the supply curves are always increasing.

2.3.3. Day-ahead market

2.3.3.1. Functioning of the market and definition of the exchanged products

The day-ahead market occurs once a day. It deals with the sale and purchase of energy for all hours of the next day. The products traded on this market are hourly products, as it is the case currently in France. As studied previously, this market is not modelled using a single and centralized UCM where technical constraints are explicitly considered but by defining a bidding strategy for BRPs where technical constraints are implicitly considered. Moreover, only simple bids are considered within the bidding strategy (i.e. bids defined with a price and a quantity for one hour only). Complex bids, such as multi-hour block bids or linked bids, are not considered in order to simplify the modelling. As it will be seen in the following section, the exclusive use of simple bids limits the consideration of the non-convex technical constraints of plants. A method is suggested to partially offset this limitation.

2.3.3.2. Actions of BRPs[33]

In this market, BRPs define both demand and supply. To simplify the construction of these two variables, it is assumed that BRPs necessarily rely on the day-ahead market to sell all their production or to purchase all the energy consumed by their customers. In particular, no self-supply within their portfolio is considered (i.e. a BRP cannot use its own production to supply its consumers directly: it has to rely on the market) and no over-the-counter exchanges take place. BRPs are also assumed to behave benevolently in order to generate market conditions as close as possible to perfect competition despite non-convexity and price uncertainty.

2.3.3.2.1. Definition of the demand curve on the day-ahead market

The demand curve for each BRP is equal to the day-ahead forecast of the residual consumption of its portfolio. The residual consumption refers to the estimated gross consumption of its customers from which the estimated non-dispatchable generation of its portfolio is subtracted. Finally, for simplicity, BRPs' demand is considered as inelastic.

[33] The TSO does not intervene on this market.

2.3.3.2.2. Definition of the supply curve on the day-ahead market

This section only concern BRPs with dispatchable plants. Bids are made on a plant basis to better reflect their technical constraints and costs. It is also considered that each plant can submit a supply curve, and not only a single bid, i.e. it can submit different prices for different volumes (for example from 0 to 100 MW, the price is set at 10 €/MWh and from 100 to 200 MW, it is set at 20 €/MWh, the only condition being to have increasing prices). The use of a supply curve enables to better reflect the uncertainty on the day-ahead prices: for a low expected day-ahead price, the plant bids a small quantity; for a higher price, it wants to produce more and then bids a larger volume. The proposed bidding strategy is different for thermal and hydroelectric power plants.

2.3.3.2.2.1. Bidding strategy for thermal power plants

Due to the consideration of the non-convex technical constraints and the start-up costs, the bidding strategy of these thermal power plants must be more elaborate than a bid defined by a price equal to the variable cost and a volume equal to the maximum output. With this strategy, start-up costs cannot be considered and BRPs run the risk of having their plants accepted by the market for one hour only while they do not intend to start them up[34]. The bidding strategy is inspired by Maenhoudt and Deconinck (2014). It enables to consider technical constraints of the plants but in a simplified and imperfect way because of the limitation to the simple bids, as well as to reflect the possible start-up costs. Moreover, different expected day-ahead price scenarios are considered to reflect the associated uncertainties faced by BRPs when submitting their offers. Two steps are distinguished in this strategy. These steps are described extensively in appendix B. Their main principles are presented below:

- Step 1: Study of the optimal production for each thermal plant, for each hour of the next day and for each expected day-ahead price scenario separately, based on a UCM in which each BRP seeks to maximize the profit of its portfolio while considering this BRP as a price taker. BRPs consider several day-ahead price scenarios for which the optimization problem is solved separately: it enables to

[34] However, this simple bidding strategy is formulated for the nuclear power plants (i.e. a bid at their variable cost and for a quantity equal to their maximum output minus the upward reserves). This is possible for this type of plants since less stringent technical constraints are considered (in particular, there are no start-up and shutdown decisions) and since their functioning as baseload reduces the risks of not being accepted by the day-ahead market.

better reflect the price uncertainty since generation decisions will be different depending on the price scenarios. Moreover, constraints for the provision of RR for each plant identified to provide them are added within these UCMs.

$$Max\ Profit = \sum_{\substack{Thermal\ plants \\ of\ the\ BRP}} \sum_{2\ days} [Q_{th} * \widehat{P_{DA}} - C(Q_{th})]$$

$$Under\ the\ technical\ constraints\ of\ thermal\ power\ plants$$

$$Under\ the\ technical\ constraints\ of\ plants\ identified\ to\ provide\ reserves$$
$$(plants\ identified\ to\ provide\ reserves = parameters^{35}\ of\ the\ UCM)$$

$With$: Q_{th} $the\ optimal\ production\ of\ the\ thermal\ plant$

$\widehat{P_{DA}}$ $the\ estimated\ day - ahead\ price$

$C\big(Q_{th}(h)\big)$ $the\ production\ costs\ of\ the\ thermal\ plant\ (variable\ cost + startup\ costs\ if\ any)$

- Step 2: Construction of the supply curve for each hour and each plant based on the previous optimal generation results. The results of the UCMs are used to define the volume each plant offers per hour on the day-ahead market. For instance, if with the lowest price scenario the optimal production is 200 MW, the associated bid will be 200 MW. If with the second lowest price scenario the production rises up to 300 MW (for a higher estimated price, the plant wants to produce more), the plant offers an additional bid whose volume is equal to the difference between the optimal productions in both scenarios (i.e. 100 MW). It should be noted that the submitted volumes consider the constraints for the provision of RR since they are explicitly added in the UCM (for instance, if a plant is identified to provide downward RR, it bids a volume larger than its minimum output to be able to provide this volume of RR in real time). Regarding the associated price for each volume, the principle of this bidding strategy is to maximize the probability of being accepted by the market when the plant wants to produce (and conversely of not being accepted when the plant does not want to produce) while reflecting part of the start-up costs in the bids price. Thus,

[35] Power plants which are planned to provide reserves are identified thanks to the previous procurement stages: then, it is an input parameter in this optimization, and not a variable anymore.

according to Maenhoudt and Deconinck, the price has to respect the following criteria (more details in appendix B):

- When the plant wants to produce, the associated bid always has to be lower than or equal to the estimated day-ahead price scenario. Otherwise the BRP anticipates that its bid will be rejected by the market.
- Whenever it is possible, the plant submits a price above its variable cost to integrate any start-up costs it may bear, i.e. a mark-up is added to the variable cost of the plant. In particular, start-up costs are spread over the whole day for which bids are studied[36] and the mark-up is assumed proportional to the difference between the variable cost of the plant and the estimated day-ahead price[37].

This bidding strategy is illustrated in a simplified way for two hours and two forecast day-ahead price scenarios in figure 11.

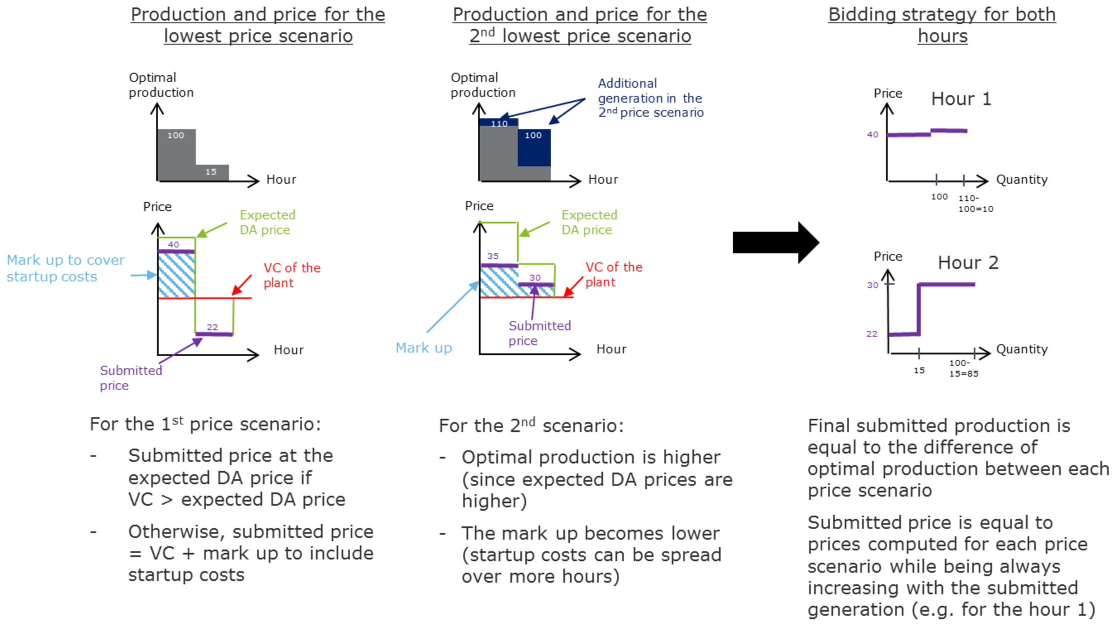

Figure 11: Simplified illustration of the bidding strategy for thermal power plants[38]

[36] These costs are spread over one day to avoid a too high mark-up on a single hour which increases the probability that this bid is rejected.
[37] For instance, a plant with a variable cost of 20€/MWh will increase more easily its submitted price in absolute terms if the estimated day-ahead price is 50€/MWh than 22€/MWh (because the probability of being rejected in the second case is higher).
[38] DA= Day-ahead ; VC = Variable costs

2.3.3.2.2.2. Bidding strategy for the hydroelectric power plants

Hydroelectric plants cannot follow the same bidding strategy as thermal power plants. Indeed, the thermal bids are based on the fact that the production level changes with the day-ahead price scenarios: it then enables to construct several bids for a same plant. However, due to the reservoir constraint, the expected optimal production for a hydroelectric plant is always the same regardless of the estimated day-ahead price scenarios[39]. To give more flexibility for the "hydraulic" bids (and then to avoid submitting a unique bid equal to the optimal production computed thanks to the UCM), the method suggested by Garcia-Gonzalez et al. (2006) is implemented. This method is described in appendix C. It enables the equivalent hydroelectric plant to submit different bids on the day-ahead market. Each bid corresponds to a deviation from the optimal production given the expected day-ahead scenarios at a price which reflects the cost of this deviation in terms of valuation of stored water. For instance, the plant agrees to increase the offered quantity (i.e. to produce more than the optimal production) provided that the day-ahead price remunerates it at a sufficient level that reflects the foregone profit of not using this water later on during more profitable hours. Bid formulated by the plant then reflects the level that the day-ahead price should exceed so that it is more relevant for it to sell the water on the next day rather than to keep it in the reservoir and use it later. Moreover, similarly to thermal bids, the provision of RR are considered in these bids thanks to the constraints of the UCM. For instance, if hydroelectric plants are identified to provide downward RR, they bid at least this volume on the day-ahead market[40].

***

Once the supply curves are defined for all thermal and hydroelectric power plants, they are aggregated and confronted with the demand to determine the clearing of the day-ahead market. Since simple bids only are considered, the clearing is simply defined as the intersection of both curves.

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[39] To prove that, let us consider the case where there is one hour when the production is lower for scenario 1 (low expected prices) than scenario 2 (high expected prices). Because of the reservoir constraint, there is necessarily an hour when the production for scenario 1 has to higher than for scenario 2: this would mean that the plant wants to produce for a low expected day-ahead price but not for a higher price, which does not seem relevant and cannot be translated into bids submitted on the day-ahead market. Thus, the hydroelectric production must be the same regardless of the estimated day-ahead price scenarios.

[40] Since the minimum output of hydroelectric plants is zero.

Main assumptions:

- Demand on the day-ahead market is defined based on the forecast residual demand and is assumed inelastic.
- Regarding the supply side, only simple bids are considered.
- For thermal plants, a bidding strategy which tries to reflect technical constraints and variable and start-up costs is used. This strategy is based on a UCM for each plant considering several price scenarios. In particular, BRPs can submit different volumes for each plant (reflecting their uncertainty about the future prices) and can formulate bids above their variable costs to cover their start-up costs.
- For hydroelectric plants, the assumed bidding strategy is based on the possibility to deviate from the optimal production (defined using a UCM) at a price which reflects the cost of this deviation in terms of valuation of stored water.

2.3.4. Modelling of the rescheduling stage

The rescheduling stage does not represent a particular market of the short-term sequence. However, it is necessary and essential for the simulation and to ensure a feasible production schedule of power plants. Therefore, it is introduced in a distinct section.

Results of the day-ahead market allocate to each BRP an amount of energy it commits to produce for each hour. However, the day-ahead market does not specify which power plants must produce this quantity. Since technical constraints are not explicitly considered within these bids, the quantity accepted by the market may not be technically feasible. For instance, a bid may have been accepted at its maximum output for one hour but at zero for the following one which is impossible from a technical point of view.

In order to determine the technically feasible generation schedule for each power plant, a new UCM for each BRP is introduced with a 30-minute time step. The objective function of this UCM is to minimize its production costs while respecting the technical constraints of its plants, the reserves it committed to provide and the quantities sold and purchased on the day-ahead market. More precisely, BRPs consider the cost of having an imbalanced portfolio within the objective function. The portfolio imbalance is defined as the difference between, on the one hand, generation and purchased energy on the day-ahead market and, on the other hand, consumption and sales on this market. Several reasons may explain the presence of imbalances within a portfolio:

- The temporal non-alignment between products traded on the day-ahead market, which are defined on an hourly time step, and the actual consumption and production that are defined every 30 minutes;
- The new forecast of the residual demand made in intraday: the quantity purchased on the day-ahead market is no longer equal to the forecast demand;
- The technical constraints of power plants that may make impossible to produce exactly what has been sold on the day-ahead market.

For these reasons, a BRP may be imbalanced: in this case, it will be subject to the imbalance settlement prices (ISP) in real time[41] and such prices (or an estimation of them) should be considered in the rescheduling UCM to determine the optimal strategy of the generation schedule (cf. example of figure 12[42]).

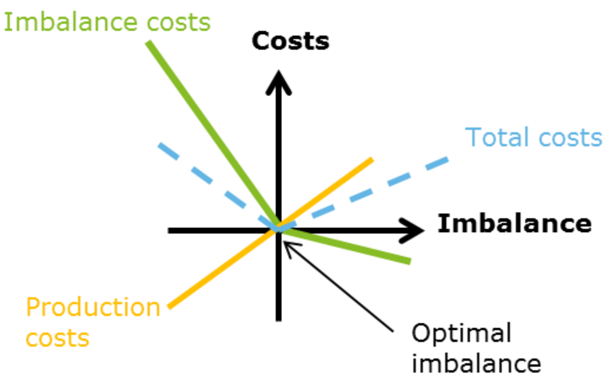

Figure 12: Example of determination of optimal imbalances for one BRP considering expected ISP

[41] In reality, BRPs can try to solve their imbalances thanks to the intraday markets. However, since intraday prices are difficult to anticipate and since it is uncertain to what extent BRPs will be able to solve their imbalances with these markets, the worst case is considered in the rescheduling stage, i.e. the case where BRPs are imbalanced in real time and are subject to the associated ISPs.

[42] This graph can be interpreted as follows: by being negatively imbalanced, a BRP can reduce its production costs but it will have to pay the ISP. Conversely, by being positively imbalanced, it increases its production costs but it will receive the ISP. The optimum imbalance corresponds to the minimization of both costs: the BRP will therefore seek this optimum thanks to the UCM based on anticipated imbalances prices.

Imbalances prices considered in the rescheduling UCM

Forecasting the ISPs is complex because they depend on many parameters (the imbalance of the system, the prices of reserves activated to solve this imbalance, etc.) that BRPs do not know at that time. A simplified construction of imbalances price is suggested below.

First, BRPs are assumed not to be able to anticipate the aggregated imbalances of the system. Therefore, they do not seek to be deliberately imbalanced in the opposite trend of the system. If a BRP is positively imbalanced, the expected cost of imbalances for that BRP is computed assuming that the system is positively imbalanced too, i.e. the BRP worsens the system imbalance. This situation represents the worst case for the BRP and seems to be the most likely[43].

In order to model a benevolent behaviour with market conditions as close as possible to perfect competition (so with no imbalance gaming and market manipulation), a very detrimental ISP is considered for the rescheduling UCM: it limits BRPs' imbalances and avoid any irrelevant trade-off between imbalances and generation. However, imbalances remain possible if they cannot be avoided or too expensive to be solved. Expected ISPs within the rescheduling UCM are therefore built according to the following points:

(1) The expected ISP is based on the worst situation that may happen in real time on the balancing mechanism, that is to say:

- Upwards: the activation of the most expensive technology, i.e. the combustion turbines. Their variable costs are then considered for negative imbalances.
- Downwards: the activation of the less expensive technology, i.e. the nuclear power plants. Their variable costs are then considered for positive imbalances.

It can be seen as a hedge for BRPs against the most detrimental situation that can happen in real time.

(2) An ISP which is extremely detrimental beyond a certain volume of imbalances is considered to avoid excessive imbalances.

Imbalances beyond this volume are not prohibited but they are limited to imbalances whose alternative would be too costly. It acts as a "safeguard" to avoid excessive

[43] Assuming that the BRP does not anticipate the future trend of the system, if it is positively imbalanced, it will increase the likelihood that the system is ultimately positively imbalanced.

imbalances which could have large consequences for the system. Arbitrarily, a volume of 500 MW is chosen as a limit. Beyond this volume, negative imbalances are valued at the start-up cost of a combustion turbine and positive imbalances are valued at a zero, i.e. the BRP does not receive any compensation.

(3) The assumed expected ISP is different for the BRP EDF

A distinction for the BRP EDF is necessary because it owns both the nuclear power plants which define the ISP in case of positive imbalances and the combustion turbines which define the price of negative imbalances. To avoid any trade-off between the use of these plants and the ISPs that would not necessarily be relevant, an even more detrimental ISP is considered for the BRP EDF in the modelling (arbitrarily, 500€/MWh for negative imbalances and -20€/MWh for positive imbalances, regardless of the volume of imbalances).

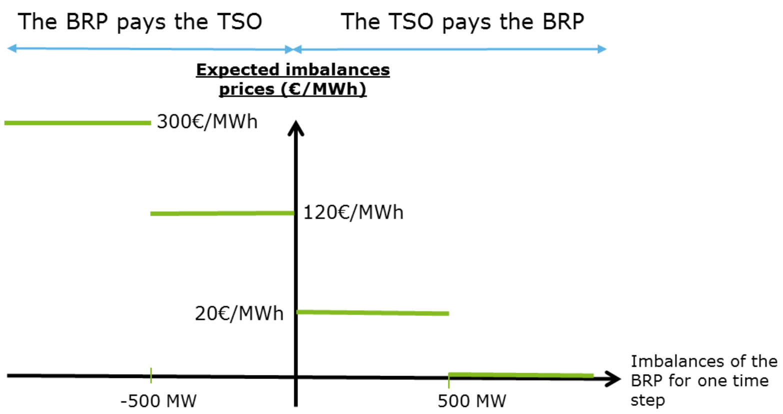

Figure 13: Estimated ISPs considered for BRPs other than EDF

Estimated ISPs considered for BRPs other than EDF are illustrated in figure 13. Considering these prices within the UCM then enables BRPs to be imbalanced if they cannot do otherwise technically (and avoid an impossibility of solving the optimization problem) and be imbalanced if the alternative is too expensive.

Thus, the optimization problem considered for the rescheduling stage is as follows (in a simplified way)[44]:

[44] Two days of costs and profits are considered for thermal power plants: for the second day, production is valued at the estimated day-ahead prices because this market has not yet occurred. For hydroelectric plants, up to two weeks are considered and the production on days other than the first one are also valued at these prices. In addition, the power plants identified to provide reserves are assumed to be variables of the

$$Max\ Profit = \sum_{\substack{Thermal\ plants\\ of\ the\ BRP}} \sum_{1st\ day} -C(Q_{th})$$
$$+ \sum_{\substack{Thermal\ plants\\ of\ the\ BRP}} \sum_{2nd\ day} [Q_{th} * \widehat{P_{DA}} - C(Q_{th})]$$
$$+ \sum_{\substack{Hydro\ plant\\ of\ the\ BRP}} \sum_{\substack{Up\ to\ 2\ weeks\\ except\ the\ 1st\ day}} Q_{hy} * \widehat{P_{DA}}$$
$$+ \sum_{1st\ day} Imbalance_{BRP} * \widehat{ISP}$$

$Under\ the\ technical\ constraints\ of\ thermal\ plants$

$Under\ the\ constraints\ of\ the\ water\ reservoir$

$Under\ the\ technical\ constraints\ of\ previously\ provided\ reserves$
$(plants\ identified\ to\ provide\ reserves = variables\ of\ the\ UCM)$

$Under\ the\ energy - balanced\ constraint\ of\ the\ portfolio\ for\ the\ first\ day$
$for\ each\ time\ step$:

$$Imbalance_{BRP} = \sum_{\substack{Thermal\ plants\\ of\ the\ BRP}} Q_{th} + \sum_{\substack{Hydro\ plant\\ of\ the\ BRP}} Q_{hy} + Purchase_{DA} - Cons._{BRP} - Sale_{DA}$$

$With$: Q_{th} $(resp.\ Q_{hy})$ $the\ optimal\ production\ of\ the\ thermal\ (resp.\ hydro)\ plant$

$\widehat{P_{DA}}$ $the\ estimated\ day - ahead\ price$

$C(Q_{th}(h))$ $the\ production\ costs\ of\ the\ thermal\ plant\ (variable\ cost + startup\ costs\ if\ any)$

$Imbalance_{BRP}$ $the\ imbalances\ of\ the\ BRP$

$\widehat{ISP}$ $the\ expected\ imbalance\ settlement\ price$

$Purchase_{DA}$ $(resp.\ Sale_{DA})$ $the\ quantity\ bought\ (resp.\ sold)\ by\ the\ BRP\ on\ the\ day - ahead\ market$

$Cons._{BRP}$ $the\ expected\ residual\ demand\ of\ the\ BRP'portfolio$

As a result of the rescheduling optimization, BRPs know the generation schedule of their power plants, in particular the production level, the start-up and shutdown decisions and the power plants which will provide each type of reserves in real time (which can be

problem: BRPs may identify different plants than those previously identified during the reserves procurement stages depending on the results of the day-ahead market.

different from plants identified during the procurement stage). In addition, the portfolio imbalances are optimized but they may be different from zero, especially if BRPs cannot do otherwise technically. To resolve these remaining imbalances, BRPs will then use the intraday markets.

Main assumptions:

- BRPs determine their generation schedule considering the imbalances of their portfolio.
- A detrimental ISP, based on the worst situation that can occur in real time, is considered in the rescheduling UCM.
- Moreover, the rescheduling UCM is based on the new intraday forecasts of consumption and intermittent generation.
- Reserves can be provided by different plants compared to plants identified during the procurement stage. However, BRPs must provide exactly the volume they have committed to.

2.3.5. Intraday markets

2.3.5.1. Functioning of the market and definition of the exchanged products

A unique session of the intraday market is modelled. It concerns all time steps of the day to come. Considering a unique market session is justified by the fact that the consumption and renewable production forecasts are updated only once on intraday in the modelling. This market occurs after the rescheduling stage to enable BRPs to solve their likely imbalances. Moreover, the exchanged products are defined on a half-hourly basis (i.e. they involve, if accepted, an increase or decrease of production over one time step only) and, like for the day-ahead market, bids are exclusively simple bids.

2.3.5.2. Actions of BRPs[45]

Similarly to the day-ahead market, BRPs intervene on the intraday market by submitting bids on the supply and demand sides. BRPs mainly use the intraday market to solve their optimized imbalances computed during the rescheduling stage. For example, if a BRP is

[45] The TSO does not intervene on this market.

negatively imbalanced, it aims at buying energy[46]. BRPs can also participate in the intraday market to sell energy by increasing the output of their power plants. They may also want to lower their generation level and then submit an associated bid (which, in that case, can be seen as a demand bid since BRPs seek a counterpart which will produce on their behalf).

Thus, two types of supply and demand bids can be distinguished:

- The supply and demand bids submitted by BRPs which want to solve their portfolio imbalances
- The supply and demand bids submitted on a plant basis (thermal or hydroelectric) to increase or decrease its production (compared to the generation schedule computed during the rescheduling stage)

This second type of bids is essential to ensure a good liquidity in the intraday market and then enable BRPs to solve their imbalances.

2.3.5.2.1. Supply and demand bids submitted by thermal plants

What is called demand for the intraday market corresponds to a plant which wants to reduce its production and therefore seeks a counterpart to produce on its behalf. To avoid any confusion with the traditional electricity demand, the terms "upward supply bids" (corresponding to an increase in the generation level) and "downward supply bids" (corresponding to a decrease) are used below (the same terms will also be used for the balancing mechanism).

Compared to the generation schedule determined thanks to the previous rescheduling stage, BRPs compute to what extent their plants can increase their production (and the corresponding price) but also to what extent they can decrease it (and the corresponding price). In order to build intraday market bids despite the high uncertainty on its very volatile prices[47], two assumptions are made.

---

[46] In particular, this market enables BRPs without dispatchable production to buy or sell energy based on new forecast of their residual consumption (since they cannot modify the generation of their plants, they are necessarily imbalanced following the rescheduling stage due to forecast errors).

[47] Unlike the day-ahead price which can be estimated in a relative simply way using the consumption forecast, it is more difficult to estimate the demand for the intraday market. Indeed, it mainly depends on BRPs' imbalances following the rescheduling stage (which can be difficult to determine by other BRPs). The intraday prices are then difficult to estimate. However, without these expected prices, it becomes difficult to find the optimal production (as it was done for the day-ahead market) and therefore the bids to submit on the intraday market for each 30 minutes.

Firstly, for each time step, bids are formulated so that if they are accepted, they do not modify the production level of other time steps, as illustrated in figure 14. Since submitted bids do not imply a generation modification for other time steps if accepted, it is not necessary to have an intraday price estimation to ensure that this change of generation on the following time steps is economically relevant (i.e. that the BRP at least covers its costs for these time steps).

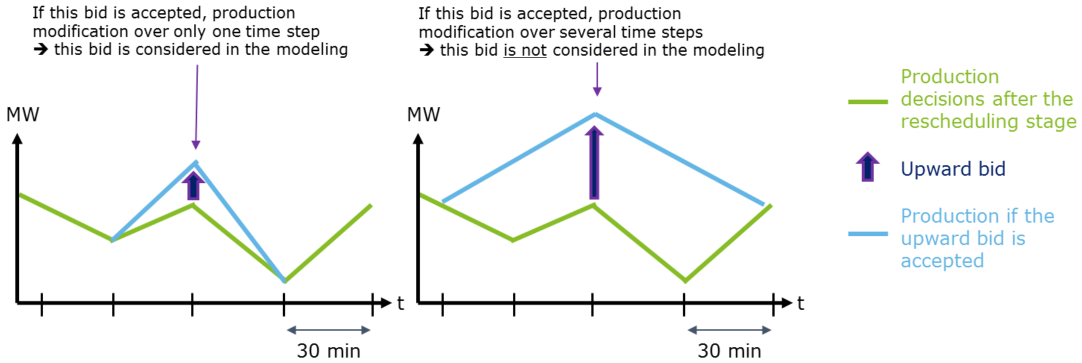

Figure 14: Hypothesis on submitted bids for thermal plants on the intraday market

Secondly, since the plant can submit upward and downward supply bids, it is necessary to arbitrate between them over several time steps. For example, in the case illustrated in figure 15, if a plant submits an upward supply bid on a time step and if it is accepted by the market, the downward bid which can be submitted on the next time step will necessarily be lower than if the upward bid was not accepted because of the ramping constraints. To arbitrate between these bids, an estimate of the intraday price would be required[48]. That is why a second simplifying assumption is made: the intraday market is considered and performed in a sequential and chronological way, i.e. the market is first solved for the time step 00h-00h30 then 00h30-01h, etc. Moreover, no trade-off is considered with the bids that could be submitted on the next time step. Regarding the situation illustrated in figure 15, these assumptions imply that the upward and downward supply bid submitted for the first time step are as high as possible (considering the first assumption made above and the technical characteristics), regardless of the consequences on the next time step if this bid is accepted by the market. Once the intraday market has been cleared for this time step, the second time step is studied. The submitted bid of the

[48] For example, is it better to reduce the upward supply bid for the first time step in order to increase the downward supply bid for the second time step or the opposite?

aforementioned plant is then computed considering whether the bid for the previous half hour was accepted or not.

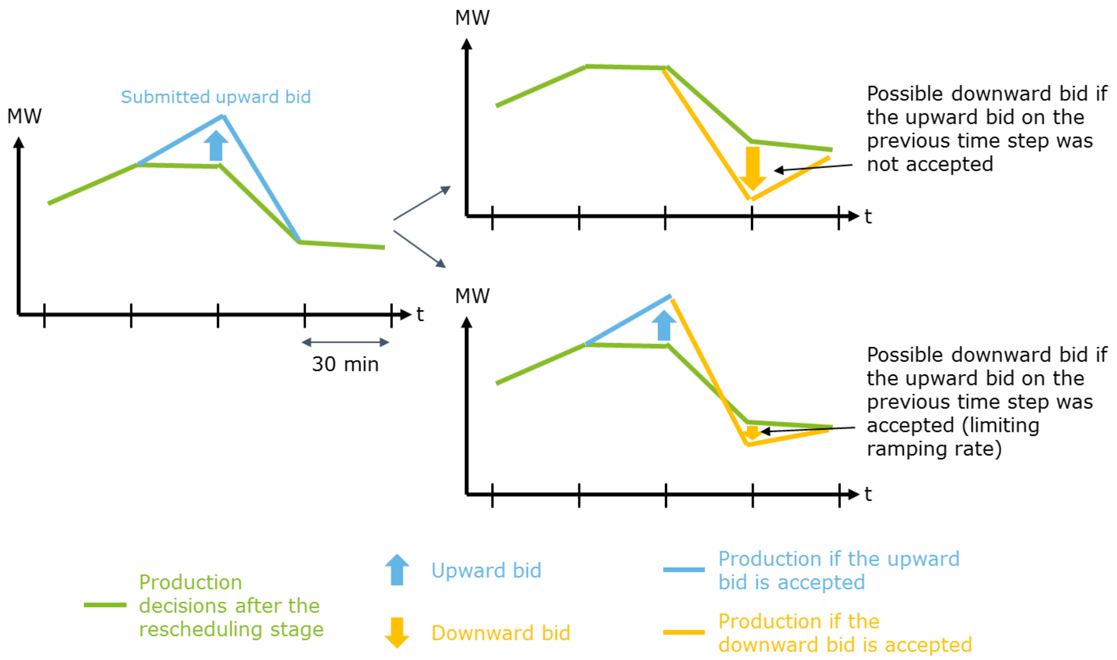

Figure 15: Example of the link between upward and downward bids over two consecutive time steps

Quantities submitted are thus mainly determined by the ramping constraints over one time step. Moreover, if a plant is identified to provide reserves following the rescheduling UCM, submitted volumes are reduced so that, whether the bid is accepted or not, the provision of these reserves remains possible in real time. These different assumptions enable to compute the submitted quantities without solving the UCM, which decreases the computation time. Moreover, only one bid is submitted for each plant (i.e. only one volume and one price). Finally, since start-up is not possible with these bids, the volumes are simply submitted at the variable cost of the plant[49] (in the case of a downward supply bid, it is the maximum price that the plant is willing to pay to reduce its production).

[49] Except for offline combustion turbines, which are able to start up in 30 minutes, and for which start-up costs are considered in the submitted bids. Indeed, a start-up bid is possible for combustion turbine since their start-up time is 30 minutes only and since they do not have a minimum up time constraint (i.e. they can be shut down immediately) as explained in Part I.3.1.1.2. Thus, acceptation of these bids would imply only one time step and then respect the firs assumption made previously.

2.3.5.2.2. Supply and demand bids submitted by hydroelectric plants

Bids submitted by hydroelectric plants are easier to compute since ramping constraints and start-ups are not considered:

- Upward supply bid of a plant is equal to the highest increase of generation that it can provide compared to the generation schedule computed during the rescheduling stage: it is simply equal to its maximum output minus the upward reserves minus its schedule production. The bid is submitted at its water value (this value is updated for each time step according to the actual use of the water reservoir and is based on the estimated day-ahead prices)
- Downward supply bid of a plant corresponds to the highest decrease of generation the plant can provide compared to its generation schedule (i.e. its schedule production minus the downward reserves), also submitted at its water value.

2.3.5.2.3. Supply and demand bids submitted by BRPs

In addition to the previous bids made on a plant basis, BRPs can submit bids in order to solve their own imbalances[50]. To compute the submitted volume, no technical constraint has to be considered here. The quantity offered (respectively asked) by a positively imbalanced BRP (resp. negatively imbalanced BRP) is equal to its computed imbalances for each time step. Then, if the bid is accepted, the BRP will be balanced after the intraday market.

Moreover, it is assumed that, if the BRPs do not solve their imbalances thanks to the intraday market, they will be subject to the ISPs in real time. As a consequence, in case of a negatively-imbalanced BRP, it agrees to pay up to the ISP to solve its imbalances on the intraday market rather than remaining imbalanced and paying the ISP in real time. To remain consistent with what was done in the rescheduling stage, a voluntarily detrimental ISP representing the worst case for BRPs is considered. Thus, a negatively imbalanced BRP submits a bid at a price equal to the variable cost of a combustion turbine. A

[50] It should also be noted that bids submitted on a plant basis and those submitted on a portfolio basis are not incompatible. A BRP can formulate both for the same time step. However, if this BRP is imbalanced, it cannot submit bids for its plants in one direction. Indeed, if a BRP is positively imbalanced, it is because it did not succeed in reducing enough the generation of its plants during the rescheduling stage (because of the technical constraints). Then, it will not be able to submit downward bids on the intraday market for its plants. However, it can submit upward bids for them. A similar reasoning can be applied to a negatively imbalanced BRP which cannot submit upward bids for its plants.

positively imbalanced BRP submits a bid at a price equal to the variable cost of nuclear plants.

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Once the different supply and demand bids are computed for each power plant and each BRP for one time step, it is possible to aggregate them to have the final supply and demand curves for each 30 minutes. It should be noticed that the demand curve is elastic in this market. The clearing is then computed as the intersection of both curves. The following time step of 30 minutes can then be studied.

Moreover, no additional rescheduling UCM is required after the intraday market. Indeed, submitted bids are defined so that the generation schedule is always possible whether bids are accepted or not. For instance, if a power plant submits an upward bid equal to 100 MW and if this bid is accepted on the intraday market, it is considered that this power plant increases its production by 100 MW, which is technically feasible given the way bids are formulated[51].

<u>Main assumptions</u>:

- A unique session of the intraday market is modelled. It concerns all time steps of the day to come. Moreover, only half-hourly products are traded.
- Intraday markets are solved in sequential and chronological way, i.e. the market is first solved for the time step 00h-00h30 then 00h30-01h, etc.
- Three types of bids are formulated on this market: bids submitted on a thermal plant basis, on a hydroelectric plant basis and bids submitted by imbalanced BRPs.

[51] A new rescheduling stage could be implemented but the new generation schedule would not be very different since exchanges on the intraday market concern a small volume and then will not modify all generation decisions. However, it would increase largely the computation time.

- Without any forecast of intraday prices, upward and downward bids submitted by thermal plants are formulated so that if they are accepted, they do not modify the production level of other time steps. Moreover, no trade-off is considered with the bids that could be submitted on the next time step (supply bid submitted for one time step is as high as possible considering the technical characteristics regardless of the consequences on the next time step if this bid is accepted by the market). These bids are submitted at the variable costs of the plants, except for offline combustion turbines for which their start-up costs are included.
- Bids of hydroelectric plants are equal to the maximum possible increase or decrease of generation and are submitted at the associated water value.
- Bids submitted by imbalanced BRPs are defined at a price equal to the ISP considered in the rescheduling stage. Submitted volume is equal to their imbalances computed thanks to the rescheduling UCM.
- Generation schedule of each plant after the clearing of intraday markets is simply defined based on accepted bids and on the initial generation schedule before the clearing (no new UCM is performed).

2.3.6. Study of available margins and of activations to ensure system margin in the French security model

This chapter concerns the French security model only. Since the margin study process in France is poorly documented in the literature, most of the assumptions made in this section result from discussions with the French TSO. It should also be noted that the margin study is a very complex task, requiring a lot of data on the power system conditions and on the power plants generation schedules: the modelling that is made in this section is therefore necessarily simplified. In particular, the margin study is performed only for dispatchable plants in the modelling (no activations to ensure system margin are considered for demand response)[52].

[52] Moreover, margins study is assumed to take place after the intraday market. It enables to consider that BRPs may have solved their imbalances thanks to this market. Then, to compute available margin and activations to ensure system margin, the TSO relies on the generation schedule of power plants following the intraday market, which is technically feasible.

2.3.6.1. Study of upward margins

2.3.6.1.1. Temporal dimensions of the study of upward margins

Three temporal dimensions are essential for the margins study:

- The target time step, i.e. the future time step for which the TSO ensures the availability of sufficient margin
- The maturity, i.e. the duration before the target time step during which the production of power plants could be modified to compute the available margin
- The time step when margin calculations are made, i.e. the time step during which the TSO computes the available margin and studies the need for activation to ensure system margin for a future target time step

These three dimensions are illustrated in figure 16.

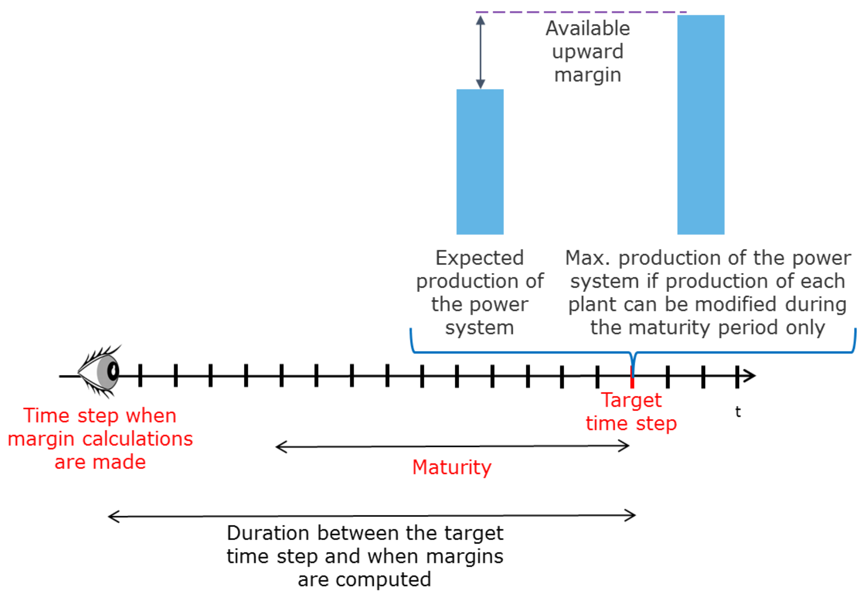

Figure 16: Time dimensions of the upward margin study

<u>Definition of the maturities studied in the modelling</u>

The studied maturities for the upward margins in this modelling are limited to the following ones: 8 hours, 4 hours, 3 hours, 2 hours and 30 minutes. The 8-hour, 4-hour and 3-hour maturities correspond to the start-up time of power plants which can be activated to ensure system margin (8 hours for a coal plant, 3 hours or 4 hours for a

CCGT[53] – see 3.1.1.2). The 2-hour and 30-minute maturities are two additional maturities that the French TSO studies.

<u>Definition of the target time step considered in the modelling</u>

The target time steps do not necessarily correspond to all the time steps of a given day. More specifically, they depend on the studied maturity. For the 8-hour, 4-hour and 3-hour maturities, the target time steps are limited to time steps included in a morning and evening peak periods (see section 3.3.2 for the definition of these peak periods). For the 2-hour and 30-minute maturities, all time steps are considered as a target time step (i.e. the TSO ensures a sufficient margin availability for all time steps of the day).

<u>Definition of the time step when margins are calculated in the modelling</u>

The TSO can only activate thermal power stations (except nuclear power plants) to ensure system margin. Thus, the time steps when margins are computed are defined by the start-up time of these power plants. Margins are calculated 8 hours, 4 hours and 3 hours before the target time step. For example, if the TSO anticipates 8 hours ahead that the available margin will not be sufficient, it will activate a coal-fired plant to ensure system margin. This plant will start up in 8 hours and will be able to bring some additional margin for the target time step[54].

Once these three dimensions are defined, the margins study unfolds in three steps:

- The study of the available upward margin
- The study of the required upward margin
- The comparison of these two quantities and the study of the need for activations to ensure upward system margin (i.e. the start-up of some power plants to increase the available margin)

[53] Activations to ensure margin are not performed with combustion turbines by the French TSO since these plants can start up in 30 minutes only. Then, the TSO does not have to activate them in advance to provide more available margin.
[54] Moreover, margins are necessarily computed for a number of hours before the target time step which is greater than or equal to the studied maturity (for instance, it does not make sense to study a 4-hour maturity 2 hours ahead of the target time step). It then reduces the margin study. For instance, the 8-hour maturity is studied only once for each target time step: 8 hours ahead.

2.3.6.1.2. Step 1: Study of the available upward margin

An extensive explanation of the computation of the available upward margin according to the current practice of the French TSO is introduced in appendix D for interested readers. In particular, the available upward margin considers:

- For plants which cannot be activated to ensure upward system margin (since they are already started up –cf. appendix D for more details on the characterization of plants which can or cannot be activated to ensure system margin), the available upward margin of each plant is calculated by the French TSO as the maximum output that the plant can reach by modifying its generation during the maturity period only minus what it intends to produce for the target time step (see figure 17 for two examples). The available margin for each plant mainly depends on its technical constraints (in particular its ramping constraints and its maximum output).

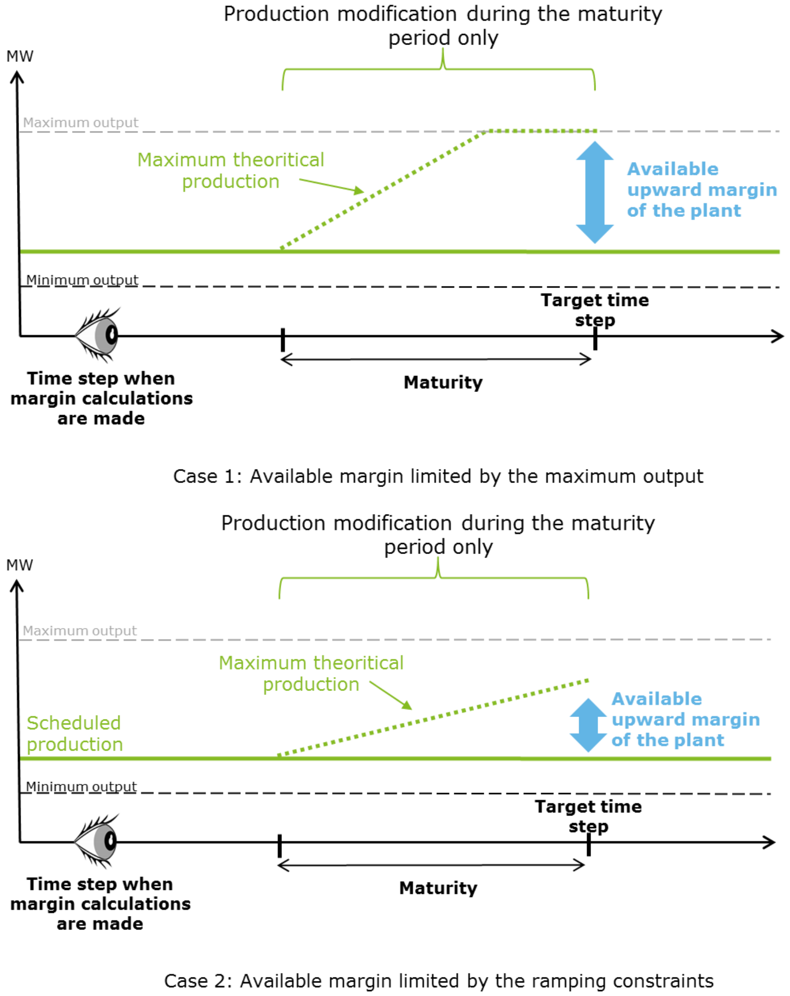

Figure 17: Illustration of the available upward margin for an online plant in two cases

- For plants which can be activated to ensure system margin (since they are offline and can be started up by the TSO if necessary): X hours before the target time step, the purpose of the margin study is to evaluate the activation need for power plants which start up in X hours only. Activation of plants whose start-up time is Y<X hours, although perhaps necessary, may wait and will be decided only Y hours before the target time step: power plants are then activated at the last moment. Thus, in order to study the need to activate plants whose start-up time is X hours only, the French TSO considers that power plants with a start-up time of Y hours (with Y <X), and which can be activated later to ensure system margin, contribute implicitly to the available margin up to their minimum output[55]. For instance, 8 hours before the target time step, CCGT plants which can be activated to ensure system margin and which start up in 3 hours or 4 hours are considered in the available margin. However, coal-fired plants which start up in 8 hours are not considered since the purpose of this margin study is to evaluate the need to activate them.
- The aggregated imbalances of the whole system as anticipated by the TSO: indeed, if the system is negatively imbalanced, the TSO has to ensure a higher level of available upward margin: part of this margin has to be available to solve the system imbalances and the other part deals with the possible uncertainties which can occur before the real time. Similar reasoning applies if the system is positively imbalanced.

Thanks to these considerations, the TSO is able to evaluate the level of available capacities, depending on BRPs' schedule decisions. Contrary to the alternative model, the TSO can rely partially on margins provided by power plants whereas the TSO has not previously procured them. Of course, this available margin will not be necessarily activated by the TSO: it is simply a guarantee for it to have enough margins to manage the system in a secure way, in particular if large imbalances occur before the real time.

2.3.6.1.3. Step 2: Study of the required upward margin

The required margin is defined according to the three previously mentioned temporal characteristics. The values are defined based on historical data and are introduced in the section 3.3.2.

[55] This implicit consideration reflects the possibility for the TSO of activating them later (i.e. the decision does not have to be made immediately). Making the activation decisions as close as possible to the start-up time of the power plant enables the TSO to activate plants only when it is really necessary and thus to minimize the costs of these activations to ensure system margin. Moreover, activation at the last possible moment enables the TSO to have a better vision for the target time step.

2.3.6.1.4. Step 3: Comparison of available and required upward margins and study of the need for activations to ensure upward system margin

Once the required and available margins are calculated, the TSO compares these two values. If the required margin is lower than the available margin, no activation is needed. If it is not the case, the TSO activates one (or several) power plant(s) to ensure the upward system margin. The TSO necessarily activates a plant whose start-up time matches the duration between the target time step and the time step when margins are calculated. If several plants can be activated (because they have the same start-up time), the TSO first activates those with the lowest costs. In addition, the TSO activates as many power plants as necessary, i.e. until the additional margin provided by the activated power plants balances the missing margin.

Activating this (or these) plant(s) to ensure system margin results in its (their) start up. The TSO remunerates it and the associated production costs for running at their minimum output during their minimum up time. Once activated, this plant has to produce during its minimum up time and then can be shut down (see figure 18). The additional upward margin provided by this plant to the system is equal to its minimum power (the generation that it adds to the system for the target time step).

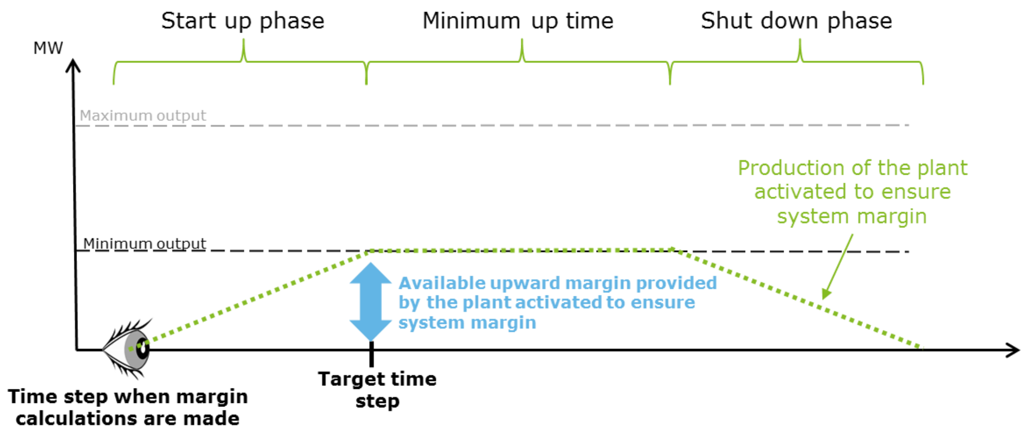

Figure 18: Production of a plant activated to ensure system margin

Moreover, once the plant is activated by the TSO, the BRP which owns it cannot use it and produce with it during the activation. In particular, it cannot use the start-up required and remunerated by the TSO to continue producing once the minimum up time is over: it must let the plant shut down[56]. Furthermore, the energy produced following this activation does not modified the imbalances of the BRP which owns the plant. In particular, the generation level considered to compute its imbalances remains the same with and without activations to ensure system margin. Then, BRPs cannot be imbalanced because of an activation which they did not decide. However, the produced energy is considered by the TSO to compute how much it has to activate on the balancing mechanism. Indeed, the produced energy which does not belong to any BRP can help to solve negative imbalances in real time: in that case, the TSO has to reduce bids activated on the balancing mechanism.

2.3.6.2. Study of downward margins

The downward margin of a power system represents the greatest possible decrease of generation the power system can reach in a given duration. Contrary to the upward margin, the downward margin is constrained by the minimum output of power plants. If the TSO finds that the available downward margin is not sufficient, it will order a power plant (mostly nuclear power plants) to shut down. This decision must therefore be made several hours before the target time step. By being shut down, the plant brings to the system an additional downward margin equal to its minimum power.

Given the very low occurrence of activations to ensure downward margin (only a single downward activation occurred between 2015 and mid 2016 in France), they are not explicitly considered in the modelling. It enables not to consider the shutdown of nuclear power plants, which would have required to know the associated technical constraints, as well as the start-up costs (these values are very disparate in the literature). However, available downward margins are calculated in the modelling in order to ensure that they are higher than the required margin. For this study, the temporal dimensions considered are:

- One maturity: two hours
- The target time step encompasses all the time steps of the day

[56] In theory, according to the French rules, the BRP can use this plant without shutting it down but it must reimburse the start-up costs to the TSO. To simplify, this is not considered in the modelling.

- Since no activation to ensure downward margin is considered, these margins are studied only 30 minutes ahead of the target time step[57].

Step 1: Study of the available margin

The calculation of the downward margin for each plant performed by the French TSO is described in appendix E. In particular, it considers the greatest decrease of generation that a plant can reach in only 30 minutes and the anticipated imbalances of the whole system (but conversely to the upward margin, a negatively imbalanced system increases the available downward margin).

Step 2: Study of the required margin

The required margins considered by the French TSO are constant and are indicated in the section 3.3.2.

Step 3: Comparison of available and required downward margins and study of the activations to ensure downward system margin

Activations are not considered for the downward margin given their very low occurrence and the difficulty of modelling them.

Main assumptions:

- The margin study is performed only on dispatchable plants in this modelling.
- Only five maturities are studied for the upward margin.
- Activations to ensure downward system margin are not considered in this modelling since they almost never occur in France.
- However, available downward margins are computed in order to ensure that they are higher than the required margin.

[57] If theory, they should be studied several hours in advance to enable to shut down a nuclear plant before the target time step.

2.3.7. Balancing mechanism

The last step in the modelling concerns the balancing mechanism. Due to likely forecast errors (on the renewable production or consumption) or imbalances that BRPs could not solve with the intraday markets, BRPs are likely to be imbalanced in real time. The TSO then asks plants to increase or reduce their generation to balance the system. In particular, previously procured reserves can be activated.

2.3.7.1. Functioning of the mechanism

In the modelling, a minimum time step of 30 minutes is chosen. Imbalances are then considered and solved on a half-hourly basis[58]. It is also considered that, similarly to the intraday markets, products submitted by BRPs and activated by the TSO are defined over 30 minutes only (i.e. if accepted, they commit to increase or decrease their production for one time step only). Moreover, imbalances are solved in a sequential order, i.e. the TSO first solves imbalances for 00h-00h30, then 00h30-1h, etc.

The French TSO currently uses a proactive approach (cf. section 1.1.3.2), i.e. it tries to forecast imbalances to come and to solve them by activating reserves before they really occur. However, the TSO cannot perfectly anticipate all imbalances and then has sometimes to solve imbalances in real time. To simplify, this specific case is not considered in the modelling and the TSO is assumed purely proactive[59]. It correctly anticipates imbalances 30 minutes ahead and then activates the relevant reserves to solve them[60]. Moreover, if the alternative security model were implemented in France, it is assumed that the French TSO would continue to adopt the same proactive approach.

2.3.7.2. Actions of the TSO

In addition to the proactive approach, the TSO intervenes on this mechanism by defining the demand. It is simply the sum of the measured imbalances of all BRPs. Moreover,

[58] With this time step, activations of FCR, aFRR or mFRR may be difficult to model since their activation time is lower than 30 minutes. However, these reserves are not considered in this modelling since the procured levels are the same for both security models for the French power system.

[59] It is pertinent to assume that the forecast errors are small 30 minutes before real time and then that the TSO can forecast correctly imbalances. Significant forecast errors for imbalances are possible in case of outages on a power plant: it would then imply a reactive approach of the TSO. However, these outages are not considered in the modelling because they are very uncommon and would require simulating many scenarios to consider them properly.

[60] Moreover, with a pure proactive approach, FCR and aFRR are never activated (since they are activated only in real time): this choice reinforces the hypothesis made earlier to ignore their procurement and activations.

energy produced by plants activated previously to ensure system margin is also considered to compute the total imbalances as it can help (or worsen) the resolution of imbalances[61]. Depending on the sign of these imbalances, the TSO considers the activations of some plants in one direction only. For instance, if the system is negatively imbalanced, the TSO only activates upward bids, i.e. power plants that increase their production. In that case, the TSO activates them thanks to a merit order (as it is the case in France nowadays), beginning with the cheapest bids. If the system is positively imbalanced, it activates downward bids (i.e. plants decrease their generation), beginning with the most expensive ones. Moreover, since products submitted by BRPs are defined over 30 minutes only, the TSO only considers the next time step to solve imbalances (i.e. it does not have to consider the imbalances for the following time steps). Finally, the TSO is assumed not to be able to activate the same thermal plant in opposite directions for two consecutive time steps. This assumption is made to be consistent with the modelling choices made for the procurement of RR products.

2.3.7.3. Actions of BRPs

BRPs formulate bids for each of their plants, both upward (i.e. an increase of the production) or downward (a decrease). Two types of plants are distinguished for these bids: those which are identified to provide RR in real time and the others. For the first type, these plants are obliged to provide the procured level of reserves following the procurement stage and then formulate a bid on the balancing mechanism accordingly. For the second type, the French market rules currently require plants connected to the transmission grid to provide all their available capacities (which can be zero) to the TSO thanks to the balancing mechanism, both upward and downward (even if these capacities have not been procured). To be consistent with the section 1.2.2., these bids are called voluntary bids in this chapter (even if there are not really voluntary in the case of the French power system). In this modelling, all modelled power plants are assumed to have this obligation. Moreover, this rule would remain true if the alternative security model

[61] For instance, if the aggregated imbalances of BRPs is -200 MW, i.e. there is a lack of energy, and if the TSO previously activated 150 MW to ensure upward system margin, then only 50 MW should be activated upwards on the balancing mechanism. Conversely, if the aggregated imbalances of BRPs is + 200 MW, then energy produced by previously activated plants to ensure system margin worsens the balance and 350 MW should be activated downwards on the balancing mechanism.

were implemented in France. To formulate their bids, BRPs consider the generation schedule determined after the intraday market and which is technically feasible.

Moreover, for voluntary bids or RR, given the activation assumptions made previously (bids must be able to be activated in 30 minutes, they are defined over a single time step and activation is not possible in opposite directions over two consecutive steps for thermal plants), bids submitted by BRPs can be computed easily without solving a UCM, as for the bids submitted on the intraday market. An illustration of possible bids is shown in figure 19.

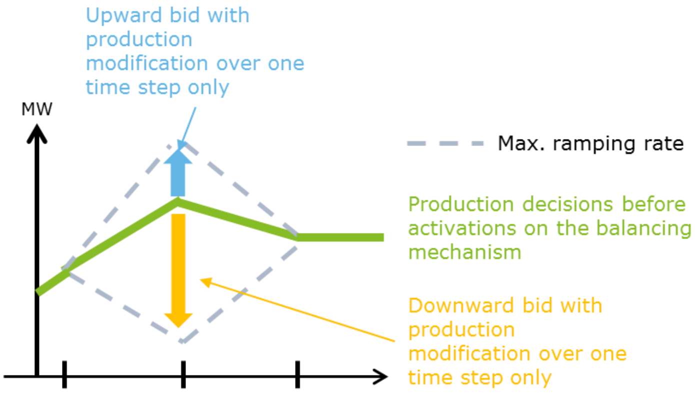

Figure 19: Assumptions about the bids of thermal plants on the balancing mechanism

For thermal power plants, upward and downward bids are submitted at their variable cost[62]. For hydroelectric plants, bids are submitted at the water value[63].

Once these bids have been defined for all thermal and hydroelectric power plants for one time step, they are aggregated and confronted with the demand defined by the TSO to determine the clearing of the balancing mechanism for this time step (i.e. the balancing price and the activations asked by the TSO). The next time step is then solved. Moreover, the final generation decisions of power plants can be easily determined based on their accepted bids on the balancing mechanism and the production decisions made after the intraday markets. For instance, if a power plant submits an upward bid equal to 100 MW

[62] Except for combustion turbines which submit a start-up offer and for which start-up costs are considered.
[63] This value is updated for each half-hour, in particular depending on the activations of the plant on the balancing mechanism for the previous time steps. For instance, if the plant was activated upwards, the water value tends to increase since the water reservoir level decreases. Moreover, like in the whole simulation, water values are computed based on the expected day-ahead prices only (i.e. the use of the stored water is valued based on the day-ahead price only).

and if this bid is accepted by the TSO on the balancing mechanism, this plant increases its production by 100 MW.

<u>Main assumptions</u>:

- Imbalances are solved on a half-hourly basis: what happens inside this time step is not considered.
- Moreover, imbalances are solved in sequential and chronological way, i.e. the balancing mechanism is first solved for the time step 00h-00h30 then 00h30-01h, etc.
- Activations of reserves other than RR are not considered.
- Products submitted by BRPs and activated by the TSO are defined on half-hourly basis only.
- The TSO is assumed purely proactive: it can perfectly forecast imbalances 30 minutes ahead of real time and then activates bids to solve them. Moreover, the TSO only considers the next time step to solve imbalances.
- The TSO is assumed not to be able to activate the same thermal plant in opposite directions for two consecutive time steps.
- Plants identified to provide RR have to formulate corresponding bids on the balancing mechanism.
- For other plants, they also have to submit their available capacity (which can be zero) on the balancing mechanism. Moreover, without forecast of imbalances prices, the volume they submit is computed with the same assumptions as for the intraday market (for instance, upward and downward bids submitted by thermal plants are formulated so that, if they are accepted, they do not modify the production level of other time steps). These bids are submitted at the variable costs for thermal plants and at the water value for hydroelectric plants.
- The final generation level of each plant after the clearing of balancing markets is defined based on accepted bids and on the generation schedule before the clearing.

2.3.8. General structure of the modelling

Once the functioning of the different markets and mechanisms have been defined, it is possible to present the whole structure of the modelling step by step. For each day of the simulation, the different markets and mechanisms are simulated in the following order (starting from 12:30 a.m.):

1) For each time step from 12:30 a.m. to 11:30 a.m.:

a. Resolution of the imbalances for the half-hourly time step

b. Study of the need for activations to ensure system margin (only if the time step corresponds to a time step for which margins should be computed)

2) For the time step 12 p.m.:

a. Procurement of the different reserves for the following day considering the day-ahead residual consumption forecast

b. Bids submission for the day-ahead market and clearing of this market, considering the day-ahead residual consumption forecast

c. Rescheduling stage for each BRP for the production of the following day considering the intraday residual consumption forecast

d. Unique session of the intraday market (for the production of the following day) considering the intraday residual consumption forecast

e. Resolution of the imbalances for the half-hourly time step

f. Study of the need for activations to ensure system margin (only if the time step corresponds to a time step for which margins should be computed)

3) For the time steps from 12:30 p.m. to 12 a.m.:

a. Resolution of the imbalances for the half-hourly time step

b. Study of the need for activations to ensure system margin (only if the time step corresponds to a time step for which margins should be computed)

In particular, it should be noted that the rescheduling stage and the intraday market are considered to take place at 12 p.m. but they rely on the intraday residual consumption forecast (forecast errors are then lower). This choice is arbitrary[64] and it would have been possible to consider these two stages at another time. However, this choice does not impact the results since the rescheduling stage and the intraday market modify production for the following day only. Thus, their results do not change production decisions from 12 p.m. to 12 a.m. of the very day, and consequently the resolution of imbalances on the balancing mechanism.

[64] In particular, information on the precise time when the real forecasts (used to assess forecast errors in the modelling) were made by the French TSO is not published on its website. Then, it is not possible to consider the rescheduling stage and the intraday market at this time.

Chapter 3. Input parameters used for the simulations: application to the French case

<u>*Résumé du chapitre 3 en français*</u> :

Une fois définies les hypothèses de modélisation, il convient d’étudier les paramètres d’entrée qui serviront pour les simulations (par exemple le niveau de demande ou les caractéristiques du parc de production). Le but de la simulation étant de comparer les effets des deux modèles de sûreté pour le système électrique français, des paramètres aussi proches que possible de ceux de ce système électrique à l’horizon 2017 sont choisis. Notamment, les RE modélisés cherchent à représenter au mieux le marché français tout en limitant la complexité de modélisation et de résolution (8 RE considérés, pour 92 centrales thermiques et hydrauliques, en plus de la production renouvelable). Enfin, tous les paramètres d’entrée définis dans ce chapitre sont pris identiques dans les deux modèles de sûreté, à l’exception des volumes de réserves à contractualiser et des paramètres d’étude des marges. En particulier, pour le système électrique français, le volume de réserves complémentaires à contractualiser est estimé à 2 300 MW à la hausse et 3 800 MW à la baisse dans le cas d’un passage à un modèle de sureté alternatif.

Ces paramètres d’entrée sont définis dans la mesure du possible à partir de données disponibles dans la littérature. Des travaux empiriques sont également menés afin de prendre en compte les interconnexions ou afin de déterminer les caractéristiques techniques du parc nucléaire français.

Ce chapitre définit également les semaines pour lesquelles les simulations sont effectuées et la méthodologie de prévision des prix utilisée par les acteurs dans la modélisation pour construire leurs offres.

Once the modelling assumptions have been defined, the input parameters used for the simulations are studied. These parameters are defined as much as possible from data available in the literature. Moreover, since the aim of this part of the thesis is to compare both security models for the French power system[65], these parameters are chosen as close as possible to those of the French one. In particular, BRPs considered in the modelling aim at representing the French market while limiting the complexity of resolution. Eight BRPs are modelled. Six of them represent the largest producers and retailers of electricity in France, namely EDF, ENGIE, EON, Direct Energie and Pont sur Sambre Power. A "Purchase Obligation" BRP, which manages the generation under purchase obligation (wind and PV mainly), is also considered[66]. Finally, a residual BRP is modelled to consider the remaining production and consumption which cannot be included in the perimeter of previously mentioned BRPs.

In the following sections, inputs parameters regarding power plants characteristics, consumption and security models are defined. Except the reserves procurement levels and the parameters used to study margins, all parameters are exactly the same in both security models. Moreover, this chapter also introduces the weeks for which simulations will be carried on and a simplified methodology to determine the day-ahead prices forecast used in the simulations. Only the main parameters are described in this chapter; explanations and the methodology used to obtain them are described extensively in appendix for interested readers.

[65] Since parameters defining both security models (in particular the margin study) are only defined for the French power system, it is not possible to study a smaller power system (which would have reduced the computation time).
[66] This BRP, even if it does not own these plants, is obliged to purchase their generation at regulated prices defined by the French laws. It is then assumed to sell this generation on the markets and to deal with likely forecast errors.

3.1. Power plants parameters

The generation fleet is defined based on the situation expected for 2017 in France. Three different types of plants are described below: thermal plants, hydroelectric plants and intermittent generation (PV and wind).

3.1.1. Parameters of the thermal production fleet

Thermal plants are divided into two categories: power plants which are considered as dispatchable in the modelling (i.e. whose generation level can be controlled by the BRPs) and those which are not. Installed capacity considered for both categories is mainly defined based on the 2015 Generation Adequacy Report published by the French TSO every year[67] (RTE, 2015).

3.1.1.1. Parameters of non–dispatchable thermal power plants

Four different technologies are considered in this category as presented in table 4.

Table 4: Parameters of non–dispatchable thermal power plants

Technology	Winter production	Production during the rest of the year	BRP
Cogeneration	2,000 MW	500 MW	Purchase Obligation BRP
Diesel generators	0 MW	0 MW	Residual BRP
Small oil and gas-fired plants	100 MW	50 MW	Residual BRP
Bioenergy	680 MW		Purchase Obligation BRP

For all these technologies, generation is considered as non-dispatchable, i.e. it is subtracted from the consumption to define the residual demand. As a result, their generation costs are not necessary, as well as their technical parameters.

[67] The 2015 report forecasts the evolution of the French generation fleet until 2020.

3.1.1.2. Parameters of dispatchable thermal power plants

In this modelling, dispatchable thermal power plants expected to be available in 2017 are considered based on the Generation Adequacy Report and on the list of certified plants for 2017 published in the context of the French capacity market[68]. The following plants are considered[69]:

- 58 nuclear reactors, with a total capacity of 63.1 GW
- 5 coal-fired plants, with a total capacity of 2.9 GW
- 14 CCGT plants, with a total capacity of 6 GW
- 13 combustion turbines (CT), with a total capacity of 1.8 GW

Considered power plants are included in the perimeter of BRPs which own them. Their cost and technical parameters are presented in table 5 below. Technical parameters of the non-nuclear thermal power plants are determined based on the average data found in the existing literature (Belderbos and Delarue, 2015; Bertsch et al., 2012; de Sisternes et al., 2016; IEA, 2011; Loisel et al., 2014; Schröder et al., 2013; van Hout et al., 2014). Regarding technical parameters of nuclear plants, the values encountered in the literature do not seem to be relevant for the French nuclear fleet, which was designed to carry out load following (EDF, 2013; Lokhov, 2011) and then is more flexible than traditional nuclear plants in other countries. Computations of these values based on historical data are described in appendix F.

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[68] See https://clients.rte-france.com/lang/fr/visiteurs/vie/meca_capa/meca_capa_rcc.jsp

[69] Oil-fired steam plants are not considered in the modelling for two reasons: 1) they are planned to be definitely closed in 2017 or 2018 (for instance, see http://www.leparisien.fr/porcheville-78440/edf-confirme-la-fermeture-de-la-centrale-de-porcheville-en-2018-18-02-2016-5558179.php or http://www.midilibre.fr/2015/10/07/gard-fermeture-actee-pour-la-centrale-edf-d-aramon,1223796.php) and 2) their technical parameters are very poorly documented in the literature and thus very uncertain.

Table 5: Considered parameters of dispatchable thermal power plants

	Max. output	**Min. output**	**Start-up costs**[70]	**Upward & down-ward ramp rate**	**Start-up & shut-down time**[71]	**Min. up time**	**Min. down time**	**Variable cost**[72]
unit	*MW*	*% of max capacity*	*€/MW of min capacity*	*% of max capacity /hour*	*hour*	*hour*	*hour*	*€/MWh*
Coal	Real values of the French power system	40	130	40	8	7	6	31
CCGT		40	115	65	3 or 4	3	3	33
CT		20	155	200	0,5	0	0	120
Nuclear 900 MW class[73]		63	/	22	/	/	/	19
Nuclear 1,300 MW class		47	/	34	/	/	/	19
Nuclear 1,500 MW class		55	/	25	/	/	/	19

[70] Start-up costs are defined as a cost per MW of minimum output. Therefore, the start-up costs depend on the size of the plant. On average, they are equal to € 31,500 for a coal-fired plant, € 20,000 for a CCGT plant and € 4,200 for a combustion turbine.

[71] Start-up and shutdown times are defined according to the start-up time of plants which can be activated to ensure upward system margin in France and whose values have been communicated by the French TSO, namely 8 hours for a coal-fired plant, 3 hours or 4 hours for a CCGT plant. Moreover, the start-up time (respectively shutdown time) corresponds to the duration to modify the production from 0 to the minimum output (resp. from the minimum output to zero), except for combustion turbines whose start-up process is more complex and explained in details in annex F.

[72] Variable costs of non-nuclear plants are calculated using the efficiency and CO_2 emission values available in the literature. A CO_2 price of 5 € / t is considered. Fuel costs (coal, gas and oil) are based on forwards values for 2017 (67 USD/t for coal based on the API2 index, 18.5 €/MWh for gas based on the PEG Nord index and 56 USD/barrel for the Brent Crude Oil). For nuclear plants, the value mentioned by the French regulator in (CRE, 2015a) is considered (around € 19/MWh). For each technology, the variable costs of each plant are considered slightly different from each other and are randomly drawn close to the value indicated in Table 5 to avoid any possible issues to solve UCMs and to compute market clearings (which may happen in case all plants have exactly the same variable costs).

[73] Since start-up and shutdown of nuclear power plants are not considered in the modelling, only the minimum output, ramping and variable cost parameters are required. Computation of these values based on past generation data is described in annex F.

Moreover, since the start-ups and shutdowns of nuclear plants are not considered in the modelling, reactors which are offline and online at the beginning of the simulation are determined based on the average historical data of the availability of nuclear plants (available in the Generation Adequacy Report of the French TSO) as illustrated in figure 20. This availability is considered identical for both security models since it only depends on maintenance and refuelling constraints.

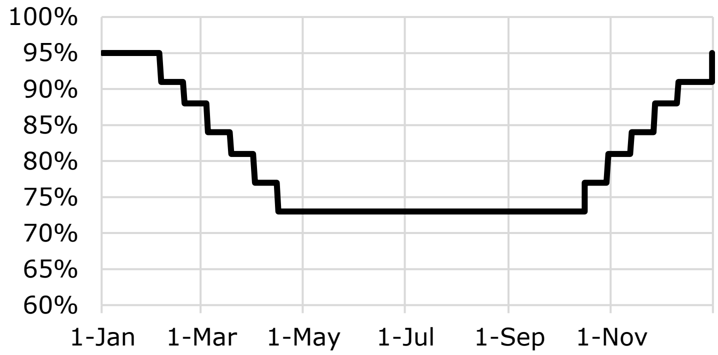

Figure 20: Considered availability of nuclear plants during the simulated year (% of total installed capacity)

3.1.2. Parameters of the hydroelectric production fleet

In the modelling, two types of hydroelectric plants are considered: production which can be considered as dispatchable by BRPs over a week horizon and production which is not considered as dispatchable over this horizon[74]. Moreover, for dispatchable generation, a unique equivalent hydroelectric power plant is considered for each BRP. Parameters of this equivalent plant are presented in table 6 for each BRP which currently owns dispatchable hydroelectric plants in France. Moreover, these parameters are considered identical all year long. Appendix F details how they are determined, notably based on a spectral analysis of the total hydroelectric production in past years in France.

Regarding non-dispatchable generation, the production is considered as fixed in this modelling (see appendix F for more details on its computation). As previously, this

[74] For instance, production variations within a month or a year or run-of-the-river generation are considered as non-dispatchable in the modelling.

production is subtracted to the consumption to define the residual demand. Moreover, due to the absence of data to quantity them, no forecast errors are assumed for this production.

Table 6: Considered parameters of hydroelectric plants

BRP	Dispatchable hydroelectric plant		Non Dispatchable hydroelectric plant
	Max. output (MW)	*Initial reservoir level (MWh)*[75]	*Max. production (MW)*
EDF	5,240	953,900	8,150
ENGIE	415	75,600	1,550
Residual BRP	/	/	610

3.1.3. Parameters of the intermittent generation

Wind and photovoltaic productions for 2017 are calculated based on the 2015 hourly load factors in France and the 2017 expected installed capacity mentioned in the Generation Adequacy Report for 2017 (namely 12 GW of wind and 7.6 GW of PV). These plants are included in the perimeter of the Purchase Obligation BRP and are considered as non-dispatchable. Moreover, agents (BRPs and TSO) do not have perfect information on the future wind and PV productions[76].These productions are estimated twice, once on day-ahead and once on intraday, and the associated forecast errors are modelled thanks to a normal distribution, centred at zero and whose standard deviation is presented in table 7[77].

Table 7: Forecast errors of wind and PV production

	Standard deviation for day-ahead forecast	Standard deviation for intraday forecast
Wind	475 MW	385 MW
PV	405 MW	

[75] A two-week reservoir level is considered at the beginning of the simulations.
[76] The TSO needs this information for the margins study and the Purchase Obligation BRP needs it to sell the associated energy.
[77] The standard deviation is determined thanks to the study of 2015 forecast errors (which are transposed to 2017 to reflect the increase in installed capacities). For PV generation, errors appear almost similar for both time horizons.

3.2. Electricity consumption parameters

3.2.1. National consumption parameters

French consumption is estimated based on the Generation Adequacy Report. It varies between 31 and 85 GW within the year and is shared between BRPs according to their market share (see appendix G). Moreover, similarly to wind and PV production, forecast errors are modelled with a normal distribution centred at zero and whose standard deviation is 970 MW in day-ahead and 630 MW in intraday[78]. Distribution of these forecast errors among BRPs with final costumers is made based on the thermo-sensitivity of their costumers[79] and is described in appendix G. Moreover, demand response is not modelled to simplify the resolution.

3.2.2. Consideration of the interconnections

Volumes exchanged with foreign countries are considered exogenously in the modelling. In particular, demand (or offer) from neighbouring countries is computed based on the expected French residual demand (i.e. when the French demand is low, France tends to export while it reduces exports or even imports during hours with high national consumption – cf. appendix G to see how this relationships was determined). This demand is added (or subtracted if it is negative) to BRPs' consumption in proportion to their national consumption. Moreover, no uncertainties are considered for this demand.

3.3. Parameters defining security models

3.3.1. Reserves procurement volumes

For FCR and aFRR products, volumes to be procured are determined by the rules of the French TSO (RTE, 2014a). In particular, the procurement volume of FCR is based on the French consumption and on the size of the largest plant in Europe and the procurement volume of aFRR is based on the French consumption only. Then, since these parameters

[78] Standard deviations are measured for 2015 based on the consumption forecast of the French TSO. The same values are considered for 2017 since the consumption level is expected to be almost the same between these two years.
[79] Portfolio with a large share of residential consumers have a higher thermo-sensitivity than portfolio with industrial consumers only. The consumption of residential consumers is then more uncertain since it varies in larger extent along the temperature.

are not modified with the introduction of the alternative security model, FCR and aFRR procurement volumes would be the same for the alternative security model. Regarding the mFRR, the upward volume to be procured is defined by the French TSO so that the total procured volume of mFRR and aFRR is equal to the size of the largest plant connected to the French grid, i.e. 1500 MW (RTE, 2014a). Similarly, since the dimensioning criterion would not change if the alternative security model were implemented in France, the procured volume of mFRR remains identical between both security models.

Then, the only difference in the procurement volume concerns the RR product as mentioned in table 8. These reserves are mainly used on the balancing mechanism to solve imbalances. In the alternative security model, the TSO cannot rely on voluntary bids to solve imbalances since it cannot react if they are not sufficient in real time. Therefore, it has to rely on procured reserves only to solve imbalances: that is why a high procurement volume is needed. On the contrary, in the French security model, the TSO can rely partly on voluntary bids since it can react by performing activations to ensure system margin if the level of reserves is expected not to be high enough in real time. Then, a lower volume of RR can be procured. An internal study carried out by the French TSO, based on historical data and whose results have been communicated to the author of this thesis shows that 2,300 MW of upward RR and 3,800 MW of downward RR would have to be procured if the alternative model were implemented in the French power system. In these chapters, these values are taken as granted and only their impacts on the power system are studied.

Table 8: Reserves procurement level in each security model

	French security model	Alternative security model
Upward RR	500 MW	2,300 MW
Downward RR	0 MW	3,800 MW

3.3.2. Parameters of the margins study in the French security model

Two parameters should be determined for the margins study:

- 1) the target time steps for which the 8-hour, 4-hour and 3-hour maturities are studied (as a reminder, 2-hour and 30-minute maturities are studied for all time steps).
- 2) the upward and downward required margins for the different studied maturities

Since there are no criteria available in the literature to define these values, a simplified analysis of historical data was carried out. Explanations of this analysis and associated results are presented in appendix H.

3.4. Representative weeks considered for the simulations

Supply and demand as defined above may result in irrelevant situations for both security models, in particular situations in which rolling blackouts are necessary (i.e. there are not enough plants to produce) while the French system is modelled as exporting electricity based on the exogenous formula to consider demand from foreign countries. Several limits of the modelling can explain this and are described in appendix I. Then, to avoid these situations for both security models and which are not relevant for the future French system (i.e. in case of rolling blackouts in France, the French power system always imports electricity), the final demand considered in the modelling should be corrected and reduced. To maintain a proper comparison between both security models, this reduction is the same in both models. Parameters of this correction are described in details in appendix I.

Following the correction, the weeks considered for the simulations can be studied. Indeed, given the computation time constraints (the resolution for one week takes about one to two hours for the French model and two to four hours for the alternative model), simulations are done over a reduced number of weeks. To ensure a good representativeness of the results over the whole year, a week of winter, summer and mid-season are considered. The way time-dependent input parameters (e.g. the value of nuclear availability, the level of consumption or the PV and wind generations) are defined for each representative week is explained in appendix J. For each type of weeks, the final and corrected residual energy demand for an "average" representative week is shown in figure 21 (the charts begin on Monday).

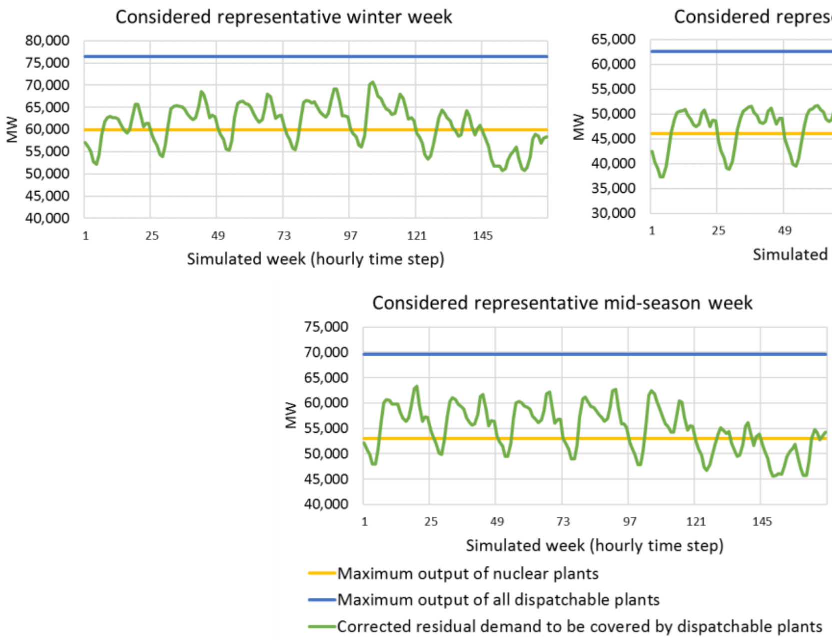

Figure 21: Representative weeks considered for the simulations

Moreover, for each type of week, five different simulations are carried out: these five simulations differ by consumption, PV and wind production forecasts performed by agents. Consequently, fifteen different simulations are performed: five for the representative week in winter, five for the representative mid-season week and five for the representative summer week.

3.5. Day-ahead price scenarios anticipated and considered by BRPs

As mentioned in the modelling chapter, BRPs use anticipated day-ahead price scenarios to compute their opportunity cost of providing reserves and to define their bids on the day-ahead market. Then, a particular attention should be paid to the estimation of these price scenarios. Indeed, for the construction of the bids on the day-ahead market, BRPs are considered to be price takers: thus, the price estimate has a strong influence on their bids and the results of this market. A methodology to forecast these prices, based on a simplified merit-order, is introduced in appendix K. The methodology is identical between both security models. However, the estimated prices can be different between them due to the different reserves procurement volumes. Moreover, a same forecast is assumed for all BRPs. This methodology is defined in order to verify the following main principles (explained in more details in appendix):

- BRPs are assumed to perfectly forecast the demand level on the day-ahead market.
- Regarding the supply level, BRPs have to forecast technologies which will provide upward reserves and then which will not be able to produce and sell energy at their maximum output. Among the upward reserves to be provided, BRPs expect that up to around 900 MW can be provided by combustion turbines while being offline and at a zero opportunity cost: these plants are then not able to sell energy on the day-ahead market. However, being extra-peak technologies, they are not expected to modify the merit order and then the day-ahead price forecasts. For the remaining volume, BRPs are not able to forecast which plants, and more importantly which technology, will provide them[80]. Then, they consider two situations: one where all remaining volume is provided by hydroelectric plants (which then reduce their production on the day-ahead market) and one where all remaining volume is provided by coal-fired plants or CCGT plants (which are also expected to reduce their production they sell on the day-ahead market)[81]. The actual situation will be probably between these two extremes cases.
- Provision of downward RR is assumed not to modify the merit-order (as it will be verified in the results).
- Based on the technologies expected to sell energy on the day-ahead market and the forecast demand, BRPs are able to predict the technology, among nuclear, hydroelectric and fossil-fuel plants, that will be marginal for each hour using a

[80] Indeed, as explained in annex, the opportunity costs of each technology will depend on the expected day-ahead prices, where these prices depend themselves on the technology identified to provide the reserves. Forecast of plants identified to provide reserves and then expected day-ahead prices are then complex for BRPs.

[81] As a baseload technology, opportunity costs of nuclear plants to provide upward RR will be higher than those of mid-merit hydroelectric plants. The case where nuclear plants are identified to provide upward reserves and then reduce their bids on the day-ahead market is not considered.

simplified merit-order (no distinction is made between coal-fired plants and CCGT plants).

- BRPs are assumed to anticipate correctly day-ahead prices when nuclear or hydroelectric plants are expected to be marginal, namely their variable costs or the water value.
- BRPs cannot correctly anticipate day-ahead prices when fossil-fuel plants are expected to be marginal (in particular since these plants will reflect their start-up costs in their bids) and then consider several day-ahead price scenarios for these hours to reflect this uncertainty.
- When two situations are considered for the provision of upward RR (provision by hydroelectric plants or coal-fired/CCGT plants), two price forecasts are computed (since different types of technologies are expected to be removed from the supply side on the day-ahead market). The final day-ahead price scenarios considered by BRPs is chosen arbitrarily as the average of both price forecasts.

An illustration of these price forecasts is introduced in the first section of the following chapter.

Chapter 4. Simulation results and comparisons of both security models in the case of the French power system

Résumé du chapitre 4 en français :

Les deux modèles de sûreté sont simulés et comparés pour quinze semaines différentes, représentant différents niveaux de demande et d'erreur de prévision sur la production renouvelable et la consommation. Le fonctionnement de chaque modèle et ses impacts sur les marchés et mécanismes de court terme sont ensuite étudiés et comparés.

Au travers des résultats, il apparaît que la mise en place d'un modèle de sûreté de type réserves impacte fortement le fonctionnement du système électrique. En effet, la contractualisation supplémentaire à la hausse se ferait principalement sur des centrales hydrauliques de semi-base (environ 1 GW en moyenne). Cela conduit à distordre le *merit order* en utilisant des centrales à charbon et CCG plus chères pour produire à la place des centrales hydrauliques dont la production est réduite pour fournir les réserves. Ces distorsions concernent un volume important (jusque 1 GW) et de nombreuses heures, à la fois durant les heures de pointe et durant les heures hors pointe (du fait des contraintes techniques des centrales à charbon et CCG, qui imposent de les laisser produire, même si d'autres moyens moins chers sont disponibles). *In fine*, cela se traduit dans le modèle alternatif par des prix des réserves à la hausse plus forts que dans le modèle français, un prix J-1 plus élevé et un prix des écarts quand le système est en écarts négatifs n'envoyant pas les bonnes incitations aux acteurs. Les coûts de gestion de la sûreté dans le modèle français (résultant des activations pour cause marge ou de l'utilisation plus forte de moyens de production chers sur le mécanisme d'ajustement à la hausse) sont très inférieurs à ceux résultant de la contractualisation supplémentaire à la hausse dans le modèle alternatif puisque le *merit order* y est distordu pour un volume beaucoup plus faible et pendant un nombre réduit d'heures (seulement lorsque des activations pour cause marge sont effectuées). De plus, ces plus faibles distorsions du *merit order* conduisent à des prix des écarts envoyant les bonnes incitations pour l'équilibrage en cas d'écarts négatifs, contrairement au modèle alternatif.

Ainsi, le modèle alternatif conduit à un surcoût de production important par rapport au modèle de sûreté français, d'environ 545 000€ en moyenne par semaine sur les quinze semaines étudiées.

La moindre efficacité économique du modèle alternatif s'explique par deux principaux motifs. En premier lieu, le dimensionnement des réserves du modèle alternatif, réalisé bien avant de connaître le besoin effectif de réserve, conduit à un surdimensionnement de la quantité à contractualiser et à une distorsion plus élevée. Au contraire, l'analyse dynamique des marges permet au modèle français de préciser le besoin réel en réserves et de limiter les distorsions du marché de l'énergie. En second lieu, l'efficacité du modèle français actuel s'explique par la prise en compte de la capacité techniquement disponible offerte par les acteurs par le biais des offres implicites (ce qui est obligatoire en France pour les centrales reliées au réseau de transport) alors que le modèle alternatif ne la considère pas. En s'appuyant sur ces capacités disponibles mises à disposition par les acteurs en dehors de toute contractualisation, le GRT dispose de davantage de ressources pour assurer un niveau de réserves suffisant et peut ainsi distordre le marché le moins possible. Dans le cas problématique où le niveau de capacités disponibles ne s'avère pas suffisant, le GRT peut en outre réagir via les activations pour cause marge. Au contraire, dans le modèle alternatif, le GRT ne peut compter sur ces capacités disponibles car il n'est pas certain de leur niveau et ne peut réagir en cas d'insuffisance. La valeur de la capacité techniquement disponible et non contractualisée est donc complètement captée par le modèle français et ne le serait que partiellement dans le modèle alternatif.

Enfin, il convient également de noter que ces différences entre les modèles de sûreté proviennent uniquement de la gestion de la sûreté et des réserves à la hausse. La contractualisation de réserves supplémentaires à la baisse dans le modèle alternatif et les activations pour cause marge à la baisse dans le modèle français ne conduisent à aucun surcoût pour le système et les deux modèles de sûreté sont équivalents sur ce point.

In this section, the results of the simulations carried out for the fifteen weeks introduced in the previous chapter are exposed[82]. Firstly, the functioning of each security model and its impacts on the short-term markets and mechanisms are studied, in particular regarding BRPs' decisions and prices. Secondly, social welfare is calculated and compared for each simulated week and each security model.

Moreover, a focus in made in these sections on the actions taken by the TSO to ensure the upward security of the power system, i.e. its ability to deal with negative imbalances. The upward security is ensured either thanks to an additional upward RR procurement (in the alternative security model) or thanks to activations to ensure system margin (in the French security model) and these two solutions will result in different outcomes. Regarding the downward security of the system (i.e. its ability to deal with positive imbalances), both security models appear similar on this point based on the results of the simulated weeks. Indeed, in the French security model, no activations to ensure downward system margin are needed. In the alternative security model, the additional downward RR are procured with baseload nuclear plants without requiring to modify their generation schedule and then at a zero cost for the system. These results are explained by the higher flexibility of French nuclear plants compared to the ones installed in other countries and by the low downward flexibility constraints imposed by intermittent production. These results (i.e. the procurement of downward RR and the study of the downward margin) are presented in appendix L and the following sections only focus on the consequences of the upward RR procurement level and the activations to ensure upward margin which explain all differences between both security models.

[82] These simulations are done based on Matlab and GAMS software using an Intel Core I5 processor at 2.50 GHz and 8 GB of RAM. Resolution for one week takes about one to two hours for the French security model and two to four hours for the alternative model (the alternative security model is longer to solve due to the higher procurement volume and the consideration of associated constraints).

4.1. Comparative study of the results of the different short-term markets and mechanisms

In this section, the results of the different short-term markets and mechanisms (in particular BRPs' production decisions and resulting prices) are explained and compared between both security models. This section will serve to explain the differences in social welfare illustrated in the second section.

4.1.1. Higher estimated day-ahead price scenarios on average in the alternative security model

Before describing the results of the different markets and mechanisms and since these results depend on the day-ahead price forecast, the expected day-ahead price scenarios are presented below in figure 22 for one winter week[83].

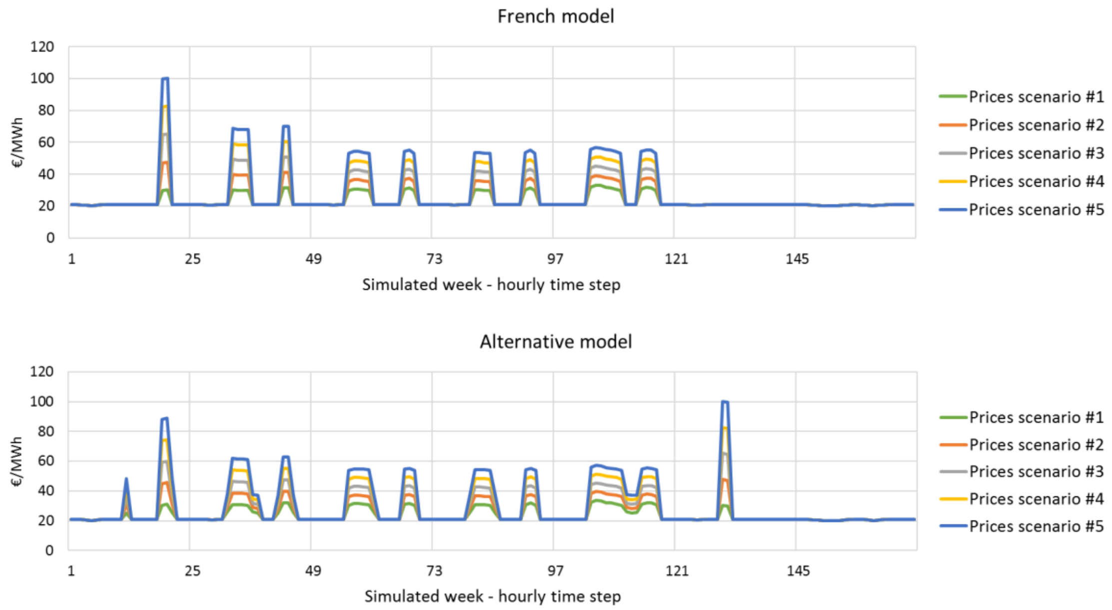

Figure 22: Expected day-ahead price scenarios for one winter week and for both security models

[83] To simplify the reading, results are mainly depicted graphically for one winter week (conclusions and explanations are similar for other weeks). In addition, all charts begin on Monday.

For the French security model, all required upward RR are expected to be provided by combustion turbines at a zero opportunity cost[84]. All technologies other than combustion turbines are then expected to sell energy on the day-ahead market up to their maximum output.

For the alternative security model, 2.3 GW have to be procured upwards. Similarly to the French security model, combustion turbines can provide some reserves at a zero opportunity cost. However, due to their maximum and start up constraints, they can provide up to around 900 MW only. The remaining 1.4 GW have then to be provided by other technologies. As explained previously, BRPs consider two opposite situations: 1) hydroelectric plants provide this volume or 2) coal-fired and CCGT plants provide it. In the first situation, since hydroelectric plants are identified as mid-merit production in these simulations (because of their large water reservoir level), reducing their production on the day-ahead market due to the provision of upward RR requires fossil-fuel plants to increase their production to satisfy the demand of electricity. In this situation, expected day-ahead prices are then higher since fossil-fuel plants are expected to be marginal more frequently. In the second situation, the hydroelectric plants can produce up to their maximum volume whereas the production of fossil-fuel plants is reduced due to the provision of upward RR. Expected day-ahead prices are lower in this situation compared to the first one since fossil-fuel plants are forecast to be marginal during less hours. Since the final expected day-ahead price scenario considered by BRPs within the UCM is computed as the average between price scenarios in both aforementioned situations, this expected price scenario is higher on average in the alternative security model than in the French one. Indeed, in the French security model, hydroelectric plants are always expected to be able to produce at their maximum level on the day-ahead market since they are not forecast to provide upward RR. In the alternative security model, these plants are expected to reduce the quantity they sell in the first situation when they are assumed to provide 1.4 GW of upward RR. This situation is perfectly illustrated on the penultimate day in figure 22: prices are always expected to be defined by nuclear or hydroelectric

[84] Indeed, since these plants are never expected to produce (demand is too low), BRPs can easily anticipate that they will provide these reserves while remaining offline.

plants in the French security model while they are expected to be defined by fossil-fuel plants for some hours in the alternative model.

Moreover, when fossil-fuel plants are expected to be marginal, the forecast day-ahead prices are computed depending on the estimated number of hours these plants will be marginal on the day to come. If they are expected to be marginal during very few hours, the expected price is high in order to cover their start-up costs (which can be noticed for instance during the first day of figure 22 for both security models). However, if these plants are expected to be marginal during more hours, their start-up costs can be spread during more hours and the expected day-ahead prices are lower than in the previous case. This is why the expected day-ahead prices are lower for the third or fourth day compared to the first one in figure 22.

4.1.2. Higher prices for upward reserves in the alternative security model[85]

In this section, technologies providing reserves as identified at the time of the procurement markets by BRPs are exposed for both security models. The procurement prices are also compared.

To identify plants that can provide these reserves and then compute their opportunity costs, BRPs solve UCMs based on the different day-ahead price scenarios. For all price scenarios and all simulated weeks, based on the results of the UCM, combustion turbines are expected not to produce due to the low estimated prices. Since they are able to start up in 30 minutes, they can provide upward RR while remaining offline, i.e. without modifying their generation schedule: then, BRPs do not forsake any revenues on the day-ahead market nor they incur additional losses (like start-up costs) by providing these reserves with these plants. The opportunity cost of providing RR with offline combustion turbines is then zero. However, the volume they can provide is limited to half of their maximum output (due to the 15-minute preliminary actions see appendix F). For the considered French power system, these plants can provide up to 900 MW while being

[85] Results of the downward RR procurement market in the alternative security model are presented in annex since both security models do not differ according to this point.

offline[86,87]. In the French security model, the RR demand is equal to 500 MW: the BRP with the combustion turbines can then provide entirely this volume at a zero opportunity cost (cf. figure 23 and figure 24). The procurement price in this case is always zero (cf. figure 25 and figure 26). In the case of the alternative security model, the RR demand is higher: combustion turbines cannot satisfy the whole demand and other technologies have to provide the remaining 1.4 GW. Nuclear, hydroelectric, coal-fired and CGGT plants can provide these reserves. However, their associated opportunity costs are generally strictly positive as explained below.

To provide upward RR, nuclear plants, which produce as baseload production, have to reduce their production and the energy they sell on the day-ahead market. It then results in forsaken revenues on this market. The opportunity cost of providing these reserves is then non-zero and is computed based on the difference between the expected day-ahead prices and the variable costs of these plants.

For hydroelectric plants, which are identified by the UCM to produce as mid-merit plants, the situation is similar during peak hours. They are identified to produce at their maximum capacity during these hours. To provide upward RR, they have to reduce the quantity they sell on the day-ahead market and the opportunity costs for these hours are also determined by the difference between the expected day-ahead prices and the water value. Since the water value is almost always higher than the variable costs of nuclear plants in the simulations (see section 4.2.1.2), the opportunity costs of hydroelectric plants tend to be lower than those of nuclear plants. During off peak hours, when hydroelectric plants are not expected to produce (based on the results of the UCM), they do not have to reduce their production and can provide upward RR while not producing[88]. For these hours only, their opportunity cost is then zero.

Finally, for coal-fired and CCGT plants, which are identified to produce as peak production after hydroelectric plants due to their higher variable costs, their opportunity costs also differ based on whether they are identified to produce or not by the results of

[86] Since the total installed capacity of combustion turbines is 1.8 GW.

[87] Combustion turbines can provide up to their maximum output if they are online. However, starting these plants to provide a higher volume of RR would imply a large opportunity cost because of their start-up and variable costs. This situation is then never considered by BRPs.

[88] Indeed, hydroelectric plants are considered as highly flexible: their minimum output is zero and they start up instantaneously.

the UCM in the scenario without procurement (i.e. when the portfolio has to provide 0 MW of reserves). If, for a given hour, they are identified to produce (since the expected day-ahead price is high enough), similarly to previous technologies, these plants have generally to decrease their production to provide upward reserves. Their opportunity costs, computed as the difference between the expected day-ahead price and their variable costs, are then strictly positive but lower than those of nuclear or hydroelectric plants. On the contrary, if these plants are not identified to produce in the scenario without procurement, they cannot provide upward reserves since they are offline. However, the BRPs may decide to start them up so that they produce at their minimum output and then are able to provide these reserves. In this situation, the opportunity costs reflect the start-up costs but also the costs of producing electricity with these plants (at least at their minimum output) while the expected day-ahead price is lower than their variable costs.

To identify the cheapest plants to provide upward reserves and then formulate the associated bids on the procurement market, a trade-off is performed between the different solutions. As mentioned above, the opportunity costs of nuclear plants are generally higher than those of hydroelectric plants and then are never identified to provide these reserves. However, the comparison between the opportunity costs of hydroelectric and coal-fired/CCGT plants is more complex since it depends on the expected day-ahead price. If this price is low, coal-fired and CCGT plants are not identified to produce in the scenario without procurement. Providing upward reserves with them would require to start them up and then imply high opportunity costs. On the contrary, since opportunity costs of hydroelectric plants are equal to the difference between their water value and the expected day-ahead price, their opportunity cost will be low if this price is low (it can even be zero if these plants are not identified to produce, as it may be the case during weekends when the demand is very low). In this situation, hydroelectric plants are identified first to provide upward reserves. On the contrary, in case of high expected day-ahead prices, several fossil-fuel plants are identified to be started up and to produce in the scenario without procurement. In this case, their opportunity costs are lower than those of hydroelectric plants and these fossil-fuel plants are identified to provide upward reserves.

This trade-off is illustrated in figure 23 which depicts plants identified to provide upward RR for each hour for one winter week. During days with very low expected prices (for instance during the weekends), hydroelectric plants are identified to provide all remaining 1.4 GW of upward reserves. For days with the highest expected day-ahead prices (for instance the fifth day), BRPs prefer providing reserves with fossil-fuel plants (and in particular with CCGT plants whose variable costs are higher than those of coal-fired plants) to providing them with hydroelectric plants whose opportunity costs are higher. For days with intermediate expected day-ahead prices, both technologies are identified to provide upward reserves proportional to their respective variable costs, their production in the situation without procurement and the expected day-ahead prices. However, hydroelectric plants tend to provide most upward reserves, in particular because they are highly flexible which enables them to provide reserves without having to produce at their minimum output or without bearing start-up costs, contrary to CCGT or coal-fired plants.

The average volume identified to be provided by each technology is presented in figure 24 for the 15 weeks. For the alternative security model, it is verified that combustion turbines are identified to provide around 900 MW for all weeks, that hydroelectric plants provide the great majority of the remaining volume and that CCGT and coal-fired plants provide a limited volume on average (only during days with very high prices). Moreover, results for the mid-season and winter weeks are quite similar. Indeed, even if demand is higher in the winter weeks, the availability of nuclear is also higher. Then, the expected day-ahead prices and the opportunity costs are almost similar between these two types of weeks. During the summer weeks, demand is significantly lower, and consequently expected day-ahead prices. CCGT and coal-fired plants are almost never identified to be online without procurement: their opportunity costs to provide upward reserves are then high since they reflect their start-up costs. It explains the lower value for these plants in figure 24[89].

[89] Moreover, for these summer weeks, as explained in annex P, the water value of hydroelectric plants is lower than for other weeks. Then, more nuclear plants have variable costs above this water value which explains the higher volume identified to be provided by nuclear plants for these weeks.

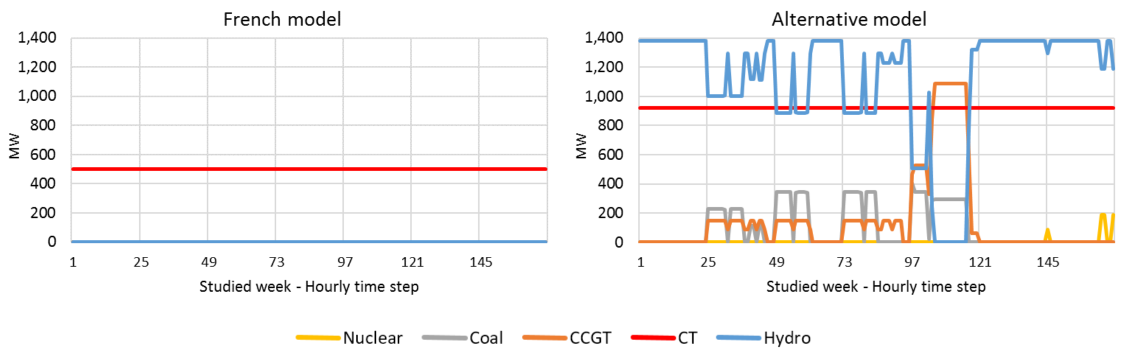

Figure 23: Technology identified to provide upward RR for each hour, for one winter week and for both security models

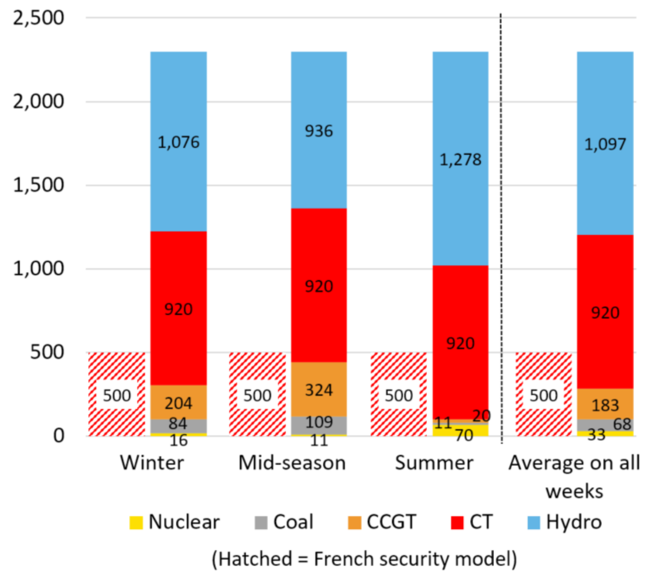

Figure 24: Average procured upward RR for each technology, each type of weeks and each security model

Moreover, since the opportunity costs of hydroelectric plants and fossil-fuel plants are almost always positive, the procurement price of upward reserves is almost always strictly positive in the alternative security model contrary to the French case (see figure 25 and figure 26). The additional procurement of 1.8 GW of upward RR in the alternative security model leads to an average increase over the fifteen simulated weeks of the procurement price by about € 125 / MW of procured RR per day (cf. figure 26). Moreover, since the opportunity cost of providing upward reserves is correlated with the expected day-ahead price, the procurement price follows the same trend as the expected day-ahead price. It tends to be lower during days with low expected day-ahead prices (for instance during the weekends in figure 25 or during the summer weeks as noticed in figure 26) and to be higher for days with high expected day-ahead prices.

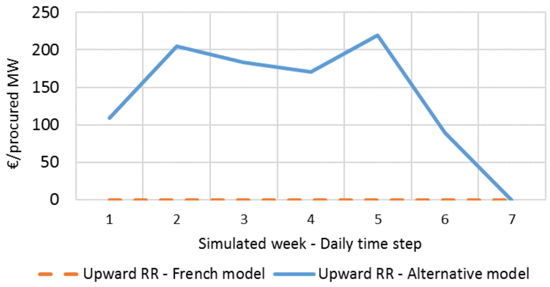

Figure 25: Upward procurement price for upward RR, for one winter week and for both security models

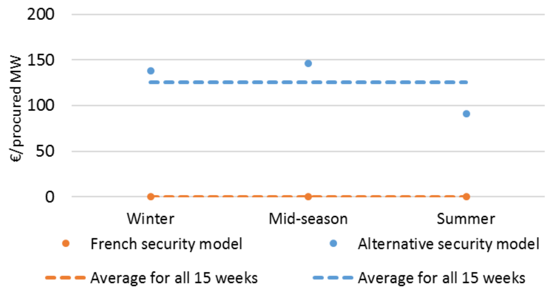

Figure 26: Average procurement price for upward RR for each type of weeks

<u>Main results:</u>

- In the French security model, all 500 MW of upward RR are identified to be provided by offline combustion turbines. The associated procurement price is zero.
- In the alternative security model for which 2,300 MW must be procured, combustion turbines can provide up to 900 MW. The remaining 1.4 GW are mostly provided by hydroelectric plants (for on average 1.1 GW). CCGT and coal-fired plants can be identified to provide part of these reserves during peak hours. The associated procurement price becomes strictly positive (around € 125 / MW of procured RR per day on average) reflecting the opportunity costs of providing these reserves.

4.1.3. Study of the day-ahead market

4.1.3.1. Higher realized day-ahead prices on average in the alternative security model

First, this section focuses on the final day-ahead price and its comparison with the day-ahead price scenarios estimated by BRPs (see figure 27 for one winter week).

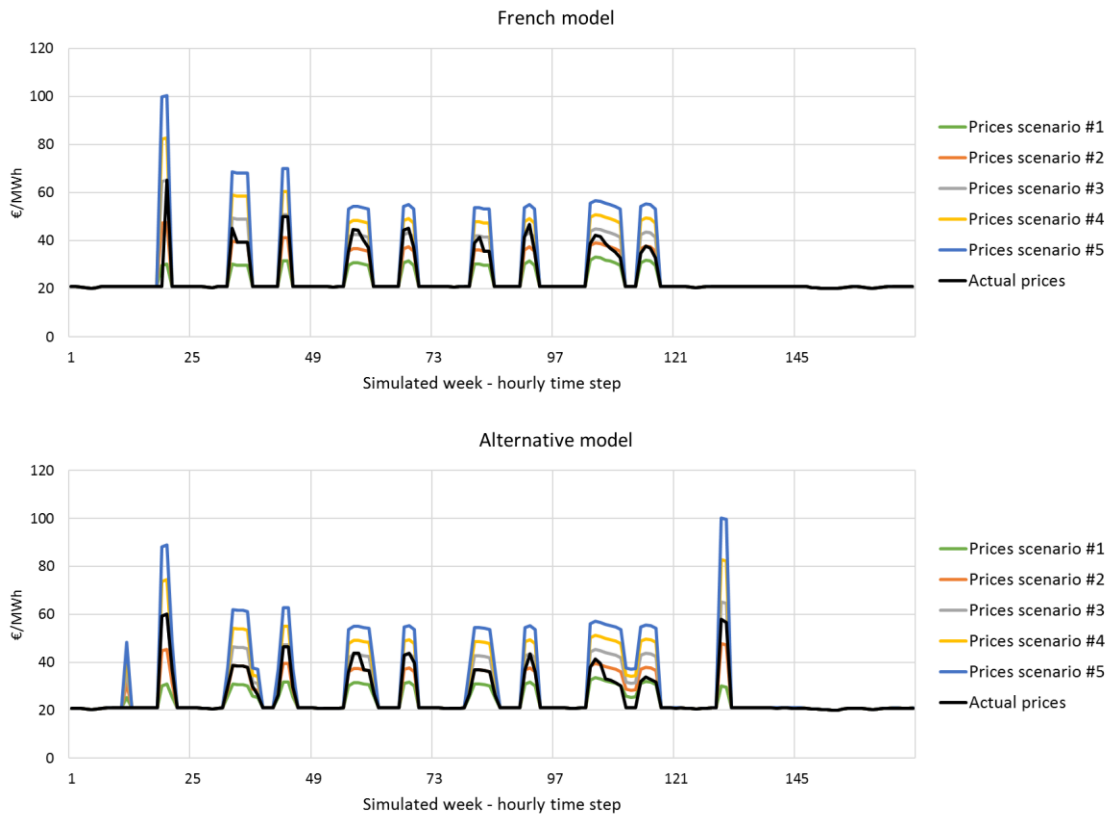

Figure 27: Expected and actual day-ahead price for one winter week and for both security models

For the week illustrated in figure 27 and more generally for all simulated weeks (see figure 28), the real day-ahead price is on average higher with the alternative model than with the French one. This difference is on average about 0.90 € / MWh.

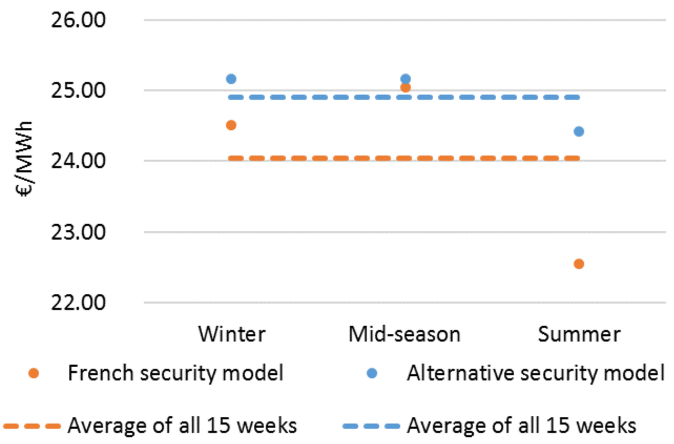

Figure 28: Average day-ahead prices for each type of week and each security model

It is explained by the impact of the additional upward RR procurement volume in the alternative security model. Mid-merit hydroelectric plants are identified to provide a large share of this additional volume. Then, these plants have to reduce the maximum volume of energy they sell on the day-ahead market. In order to cover the demand during peak hours, it is therefore necessary to accept more expensive bids from coal-fired or CCGT plants. The fossil-fuel plants then define the day-ahead price through the bids they submit. In the French security model, since hydroelectric plants are available to produce up to their maximum level, fossil-fuel plants are accepted in a lower volume and define the day-ahead price less frequently. That is why the day-ahead prices tend to be higher in the alternative security model on average.

However, the bidding strategy defined for fossil-fuel plants tends to limit the day-ahead price difference. When they are expected to be marginal, these plants bid above their variable costs in order to cover their start-up costs (or the losses they may bear during off peak hours when they have to produce due to their technical constraints whereas day-ahead prices are expected to be lower than their variable costs). In the French security model, since CCGT or coal-fired plants are expected to be marginal during few hours, the mark up is important and they bid at a high price: the real day-ahead price during these hours can then be very high so that fossil-fuel plants can cover their start-up costs. On the contrary, in the alternative security model, fossil-fuel plants are expected to be marginal during more hours. Then, these plants can cover their fixed start-up costs during more hours and on a larger production: the mark up is reduced compared to the French situation. When fossil-fuel plants are marginal in the alternative security model, the real day-ahead price can be lower (but more frequently defined by fossil-fuel plants bids). The price experienced at the end of the first day in figure 27 perfectly illustrates this point. The bidding strategy of fossil-fuel plants which always try to cover their start-up costs then explains why the day-ahead price difference between both security models is not so high.

Moreover, when comparing the different types of week, the price increase between both security models appears higher for the summer weeks. Indeed, for this type of weeks, removing a large volume of hydroelectric plants from the day-ahead market deeply impacts the merit order. When these plants can produce at their maximum capacity (i.e.

in the French security model), fossil-fuel plants are almost never expected to be marginal and the price is defined by nuclear or hydroelectric plants for most hours. In the alternative security model, since an average volume of 1.3 GW from hydroelectric plants is removed, fossil-fuel plants become marginal for many more hours and then define the day-ahead price more frequently. The price increase is then important between both security models. For the other types of weeks, fossil-fuel plants are already expected to be marginal for some hours in the French security model. Removing a large volume of mid-merit plants does not really increase the number of hours when fossil plants are marginal but only increases the volume of accepted fossil-fuel bids (which does not really increase the day-ahead price since all fossil-fuel plants have similar variable costs). Impacts on the day-ahead price are then limited for these types of weeks and the day-ahead price increase between both models is low.

Finally, it should be noticed that the bids submitted by fossil-fuels plants depend on the expected day-ahead price scenarios since they cannot submit a bid higher than these expected prices. Moreover, since these price scenarios are computed in a simplified way by considering an average price between only two situations for the provision of upward RR in the alternative security model, this forecast may be wrong. This is notably the case for the fifth day in figure 27 in the alternative model when the real day-ahead price appears to be lower than all price forecasts for some hours.

4.1.3.2. A smaller volume of hydroelectric bids accepted on the day-ahead market in the alternative security model

Beyond the final day-ahead prices, it is also interesting to study the volumes accepted for each technology on the day-ahead market. In the figure 29, the smaller volume sold (and then accepted) by hydroelectric plants in the alternative model can be noticed during peak hours due to the provision of most upward RR (except for the fifth day when these reserves are identified to be provided exclusively by coal-fired or CCGT plants). Moreover, in the alternative security model, the lower accepted volume of hydroelectric bids is offset by a higher accepted volume for coal-fired and CCGT plants during peak hours[90].

[90] Bids submitted by coal-fired and CCGT plants depend on the number of hours they are expected to be marginal over the next day due to the introduction of a mark-up to cover their start-up costs. Then, the

It is also noted that, in the absence of complex bids, the technical constraints of plants are not verified in the accepted bids. For example, in the alternative security model, for the penultimate day, bids of coal-fired plants are accepted for a limited number of hours, well below their minimum up time constraint. It then highlights the need for the rescheduling stage.

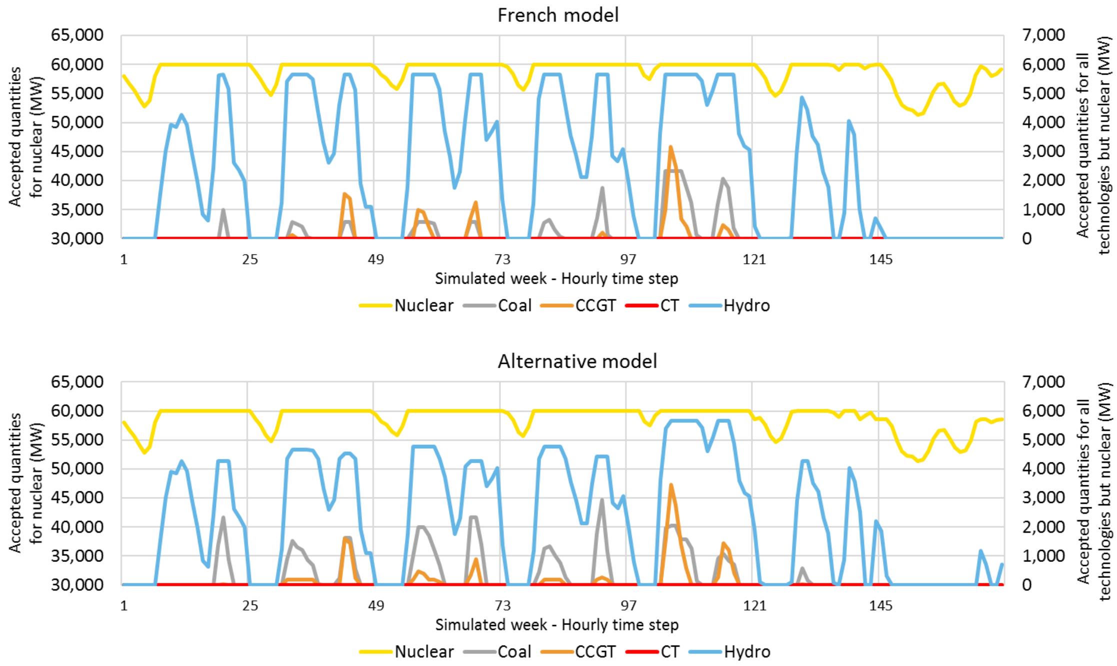

Figure 29: Accepted volume on the day-ahead market for one winter week for both security models

<u>Main results:</u>

- Due to the reduction of the bids submitted by hydroelectric plants identified to provide some upward RR in the alternative security model, more bids of fossil-fuel plants are accepted on the day-ahead market during peak hours in the alternative security model than in the French one (in which hydroelectric plants do not have to reduce the volume they sell).

merit-order between CCGT and coal-fired plants can be difficult to determine since it depends on the expectations made by BRPs. It explains why both technologies can be accepted on the day-ahead market for a volume lower than their maximum output (in other words, the CCGT plants are not automatically accepted once all coal-fired bids have been accepted).

- This translates into a higher day-ahead price on average compared to the French security model (0.90 €/MWh over the fifteen simulated weeks), even if the difference is reduced due to the bidding of fossil-fuel plants used in the modelling in order to cover start-up cost.
- Bids accepted on the day-ahead market are generally not technically feasible since only simple bids are submitted on the day-ahead market.

4.1.4. Study of the rescheduling stage

4.1.4.1. A higher production with fossil-fuels plants in the alternative security model following the rescheduling stage

Following the day-ahead market and based on the new forecasts of consumption and wind and PV productions, BRPs optimize the production of their plants while providing the reserves they commit to make available, optimizing their portfolio imbalances and considering the technical constraints of their plants.

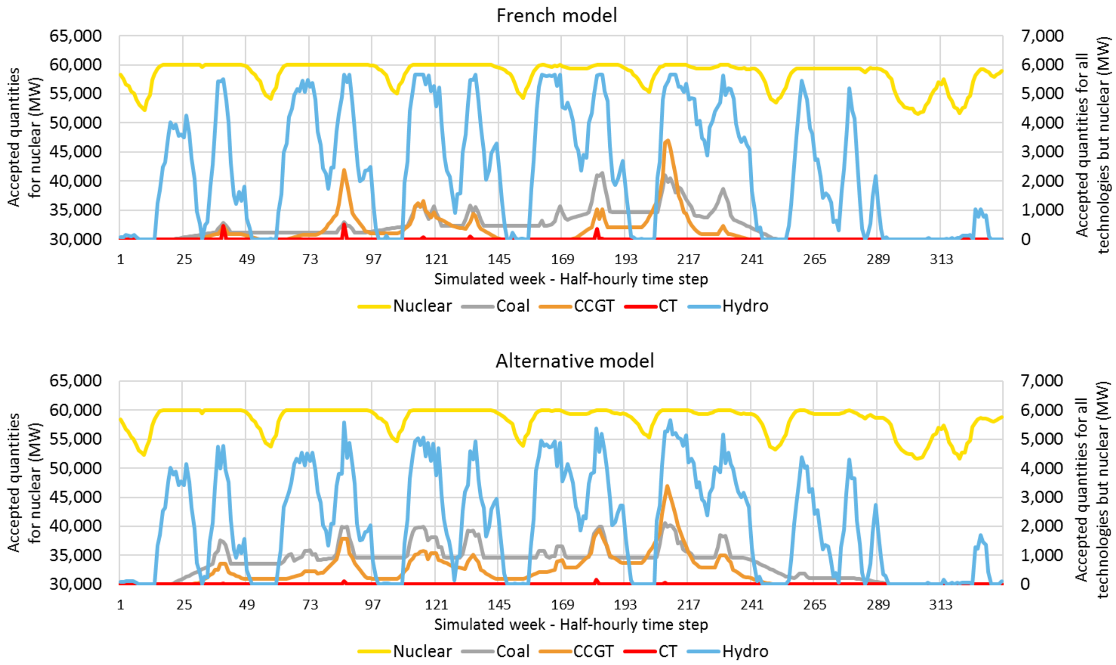

Figure 30: Generation decisions after the rescheduling stage for one winter week and for both security models

The new generation schedule for each technology is depicted in figure 30 for the same winter week as previously. The main difference compared to the accepted volumes on the day-ahead market lies in the generation of coal-fired and CCGT plants which is not limited to peak hours, contrary to what was accepted on the day-ahead market. Indeed, if bids of these plants have been accepted during peak hours, BRPs can either choose to produce with them and be energy-balanced or choose not to produce and be negatively imbalanced[91]. This second solution, even if possible, is generally not considered by BRPs. Indeed, by remaining negatively imbalanced, they consider they will pay the corresponding ISP. Since the value of this price assumed in the UCM is high (the variable costs of a combustion turbine), BRPs avoid this solution.

Then, BRPs which own fossil-fuel plants whose bids were accepted on the day-ahead market during peak periods decide to produce with some of these plants. However, due to their minimum up time constraints, these plants cannot produce during the few peak hours only: they have to produce also for some off-peak hours for which they did not sell energy on the day-ahead market. Moreover, BRPs usually prefer keeping these plants online after the peak hours and producing at their minimum output during the night to shutting them down and paying new start-up costs later for the next peak period. Then, BRPs prefer (or have to) produce with their fossil-fuel plants during off-peak periods so that they are able to produce during peak periods. It can be noticed in figure 30 in particular during the nights when the production of CCGT and coal-fired plants is not equal to zero. Moreover, since more bids of fossil-fuel plants were accepted during peak hours on the day-ahead market in the alternative security model, more plants have to be online and produce during these hours compared to the French security model. Consequently, generation from these plants tends also to be higher during off-peak periods since more plants prefer to stay online in the alternative security model (as it can be noticed in figure 30 with coal-fired plants during the nights).

During off-peak hours when bids of fossil-fuel plants were not accepted on the day-ahead market but during which they produce anyway, BRPs have to reduce the production of their other plants to avoid being positively imbalanced. However, only one BRP owns nuclear plants and then is able to reduce its production during the night to avoid being positively imbalanced. For other BRPs, they may be unable to reduce the production of

[91] Another solution would be to increase the production of other plants, like nuclear or hydroelectric plants. However, it is generally not possible since these plants, as baseload or mid-merit production, already produce at their maximal capacity.

their plants during off-peak hours since they do not own baseload plants. As a result, these BRPs remain usually positively imbalanced during off-peak hours as it will be studied in the next section.

During the rescheduling stage, BRPs have also to deal with imbalances caused by forecast errors between the day-ahead and intraday horizons. Regarding consumption, forecast errors mainly impact the BRP EDF since it has the largest market share on the retail market. Since this BRP owns many hydroelectric plants, it can solve its imbalances quite easily in the modelling thanks to the high flexibility of these plants. This explains the peculiar production pattern of hydroelectric plants in both security models: they do not necessarily produce at their maximum output during peak hours or at their minimum output (i.e. 0) during off-peak periods. Hydropower can then be seen as an adjustment variable in these simulations: its generation is modified so that the whole portfolio of the BRP which owns the plant is balanced. Moreover, to avoid being negatively imbalanced (and then paying the associated high costs considered in the UCM), the BRP EDF also uses its combustion turbines for some hours as illustrated in figure 30. For other BRPs, consumption forecast errors are small since their market share is low. Finally, regarding forecast errors for PV and wind generation, they only concern the Purchase Obligation BRP whose situation is studied briefly in the next section.

4.1.4.2. Higher and more frequent positive imbalances after the rescheduling stage for the alternative security model

Two types of BRPs can be considered when studying these imbalances:

- BRPs which do not own dispatchable production (mainly the Purchase Obligation BRP)

As a result of new forecasts, these BRPs are ineluctably imbalanced. Indeed, the energy they sold or they bought on the day-ahead market is no longer equal to their consumption or production forecasts. Moreover, they cannot solve these imbalances by modifying the production of their dispatchable plants like other BRPs. Moreover, since their imbalances depend only on forecast errors, which are considered as identical between both security models, total imbalances of BRPs which do not own dispatchable production are the same in both security models. These BRPs have to rely on the intraday market to try to solve their imbalances.

- BRPs which own dispatchable production

For these BRPs, imbalances are optimized thanks to the UCM. For BRPs with hydroelectric plants (mainly EDF), their imbalances can be avoided using their high flexibility. However, for other BRPs, imbalances cannot be solved so easily. In particular, if they own fossil-fuel plants whose bids have been accepted on the day-ahead market during peak hours, these BRPs are mainly positively imbalanced since they cannot reduce their production during off-peak periods. In particular, they prefer being positively imbalanced during off-peak hours and receiving the ISP assumed equal to the variable costs of nuclear plants in the UCM (or equal to zero for a large volume of imbalances) to not starting up the plants, being negatively imbalanced during peak hours and paying the corresponding ISP, assumed equal to the variable costs of a combustion turbine.

Figure 31 shows, for all BRPs which own dispatchable production, the average share of time steps per week when the aggregate imbalances are zero, strictly negative or strictly positive, and the figure 32 depicts the average aggregated imbalances during these time steps. Regarding these values, it first appears that in both models, the system is more often positively imbalanced, since thermal plants remain online during off-peak hours[92]. Moreover, the alternative security model is more often positively imbalanced and for an average larger volume than the French one because of the higher number of online fossil-fuel plants producing during off-peak hours. Finally, regarding the average volume of negative imbalances, both security models do not appear to be different.

[92] However, this is less the case for the summer weeks. Indeed, for these weeks, the demand is lower and less fossil-fuel plants have to produce during peak hours (for both security models). Consequently, they produce a lower volume during off peak hours and BRPs are then less likely to be positively imbalanced.

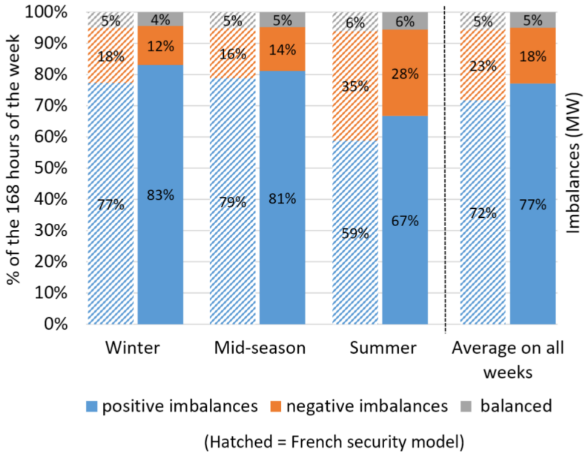

Figure 31: Average distribution of the week according to the sign of the aggregated imbalances of BRPs with dispatchable production for each type of week

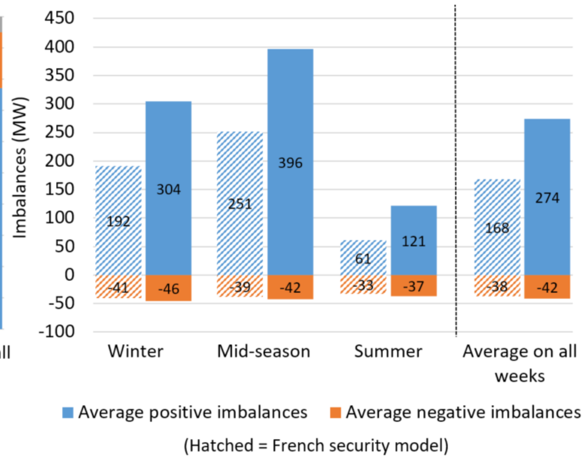

Figure 32: Average aggregated imbalances of BRPs with dispatchable production for each type of week

4.1.4.3. BRPs expect to provide reserves with the same plants as identified during the procurement stage

Moreover, during the rescheduling stage, BRPs can modify the power plants they identify to provide the reserves that they have previously committed to make available for the TSO[93]. It enables BRPs to provide reserves with the cheapest plants, while respecting other technical constraints and optimizing their imbalances. Power plants identified to provide these reserves are almost similar compared to plants identified during the procurement stage. In particular, hydroelectric plants are still identified to provide most upward RR (about 1,050 MW) since their opportunity costs remain lower than those of coal-fired and CCGT plants. Newly identified plants to provide reserves are depicted in appendix M for interested readers.

[93] However, since procurement markets already occur, the volume which has to be provided by each BRP cannot be modified. Only plants which will provide these reserves inside the same portfolio can be modified.

Main results:

- In the alternative security model, since more bids from fossil-fuel plants are accepted on the day-ahead market during peak hours, BRPs decide to produce with these plants to avoid being negatively imbalanced. However, due to their technical constraints, they cannot produce during peak hours only and BRPs have to keep them online during off peak periods (for which bids of fossil-fuel plants were not accepted on the day-ahead market).
- During these off-peak hours, BRPs try to decrease the production of their baseload plants to avoid being positively imbalanced. However, only one BRP owns baseload plants: other BRPs cannot reduce their production enough and the aggregated imbalances of BRPs is often positive in the alternative security model.
- On the contrary, in the French security model, BRPs have to produce with fossil-fuel plants to a lesser extent. Then, the aggregated positive imbalances are reduced compared to the alternative security model.
- Moreover, plants identified to provide reserves during the rescheduling stage are similar to those identified during the procurement stage.

4.1.5. Intraday markets enable to reduce imbalances of BRPs for both security models

BRPs with unsolved imbalances following the rescheduling stage rely on the intraday market to solve them. In particular, the Purchase Obligation BRP, which manages the wind and PV production, uses this market to compensate their forecast errors. The main interesting results concerning these intraday markets lie in the remaining imbalances of BRPs after this market[94]. Figure 33 shows the average share of time steps per week when the aggregated imbalances after the intraday market are zero, strictly negative or strictly positive, and figure 34 depicts the average aggregated imbalances during these time steps. Based on these results, there is a large decrease in the aggregated imbalances of BRPs in both security models compared to the rescheduling stage. For the great majority of time

[94] In particular, since bids submitted by BRPs to solve their imbalances are defined at the variable cost of nuclear plants or the variable cost of combustion turbines (the expected value of ISP), the study of intraday prices is of little interest (it is equal to one of these values most of the time).

steps, the aggregated expected imbalance is equal to zero. BRPs which were imbalanced before this market are able to find a counterpart to solve their imbalances. However, some large imbalances may persist for few hours, in particular negative imbalances. This is partly due to the restrictions imposed on bids submitted by power plants on this market. Indeed, if accepted, bids have to modify generation over one time step only. In particular, bids reflecting a start-up is not possible (except for combustion turbines) and then a negatively imbalanced BRP may not be able to find a counterpart which can increase the production of its plants during 30 minutes only.

When comparing the aggregated expected imbalances after the intraday market between both security models, both appears to solve almost all BRPs' imbalances. Remaining imbalances only concern very few time steps. It is then difficult to draw some conclusions and comparisons of both security models because of the low occurrence.

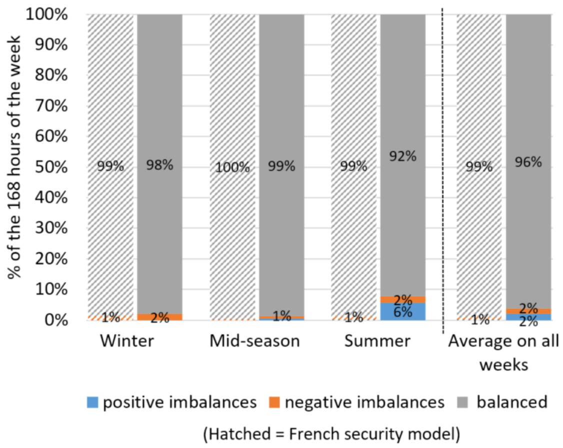

Figure 33: Average distribution of the week according to the sign of the aggregated imbalances of all BRPs after the intraday market for each type of week

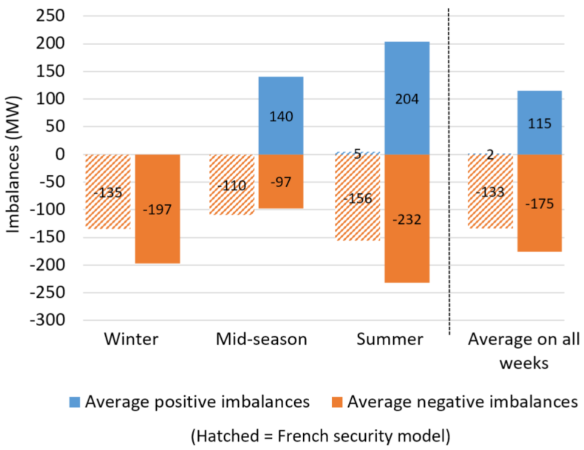

Figure 34: Average aggregated imbalances of all BRPs after the intraday market for each type of week

The generation schedule by technology after the intraday market is depicted in figure 35 for both security models for one simulated winter week.

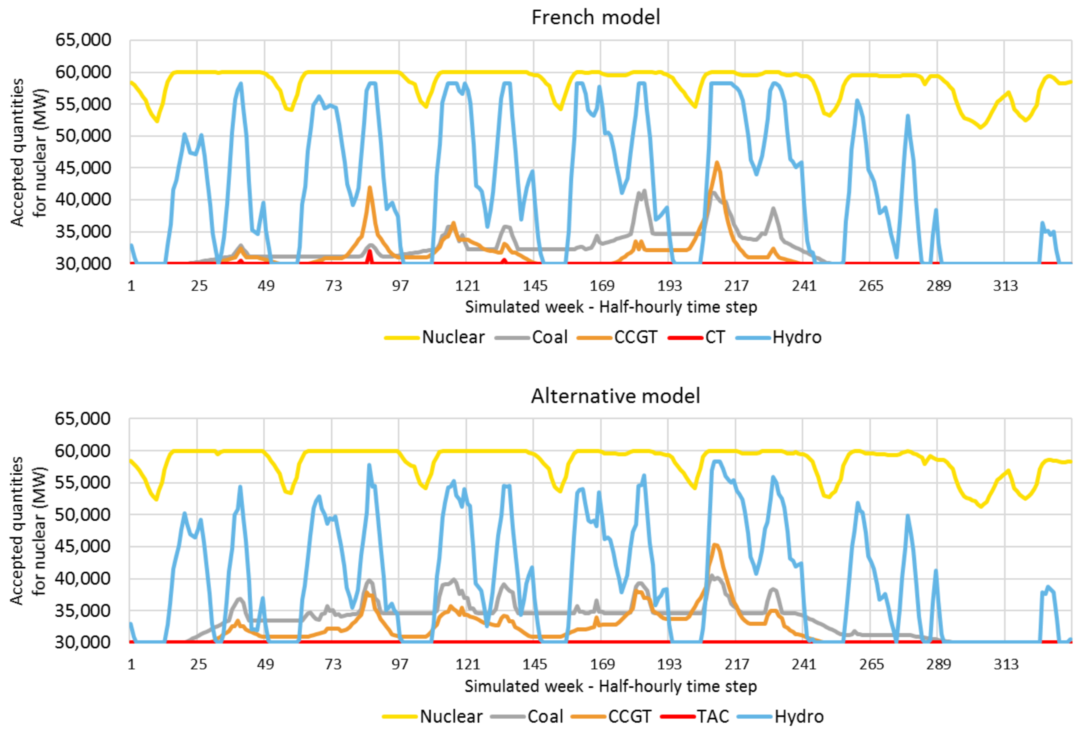

Figure 35: Generation decisions after the intraday market for one winter week and for both security models

Production decisions are really close to those decided after the rescheduling stage. Indeed, trades made on the intraday market are limited since bids are submitted over one time step only. For instance, it is not possible to start up or shut down a plant and to submit an associated bid over several time steps on this market. Then, possible modifications of production are reduced and the production schedule difference after this market are marginal compared to what was determined after the rescheduling stage. Nevertheless, two interesting points can be noticed about the modification of the generation schedule before and after the intraday markets:

- Firstly, since BRPs are mainly positively imbalanced before this market, they seek a counterpart which accepts to decrease its production. That is why it can be noticed that several technologies have a lower production schedule after the intraday market than before it. For instance, during all nights, the generation schedule of nuclear plants is reduced to solve the positive imbalances of BRPs due to the production of fossil-fuel plants which were previously started up. This is particularly true in the alternative security model.

- Secondly, the intraday market can also be used to produce electricity with cheaper plants. For instance, if an expensive plant is planned to produce during the rescheduling stage, it submits a bid to decrease its production at its variable costs. On the contrary, a cheap plant can submit a bid to increase its production, also at its variable costs. Then, a trade can be made between both bids and the production previously produced by an expensive plant is now produce by a cheaper one[95]. In particular, this can be noticed in both security models for combustion turbines. Indeed, to avoid being negatively imbalanced, during the rescheduling stage, BRPs planned to use them for some hours. During the intraday day market, they are able to trade this production with a cheaper plant and combustion turbines are expected to produce less after the intraday market (for instance, during the first or fourth day in the French security model in figure 35).

Main results:

- Aggregated imbalances are almost entirely solved thanks to the intraday markets in both security models.
- Remaining imbalances only concern very few time steps and security models cannot be compared on this point.

4.1.6. A limited number of activations to ensure upward system margin in the French security model[96]

In order to facilitate the reading of this section, only the most interesting margin studies are depicted below. In figure 36, the available upward margin for the 8-hour maturity and as calculated 8 hours before the target time step is depicted for a whole simulated winter week. The corresponding required margin and the possible need for activations to ensure system margin are also plotted. The available upward margin for the 30-minute maturity and as calculated 3 hours before the target time step is also shown in figure 37.

[95] Which was not possible during the rescheduling stage since plants can be owned by two different BRPs.
[96] Downward margins and the need for activations to ensure downward margin are presented in appendix L since they are less essential to understand the differences between both security models.

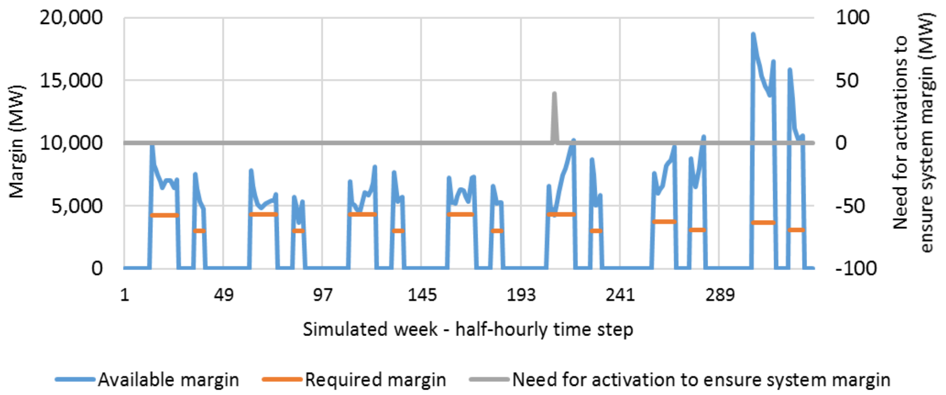

Figure 36: Study of the available and required 8-hour margin as computed 8 hours before the target time step

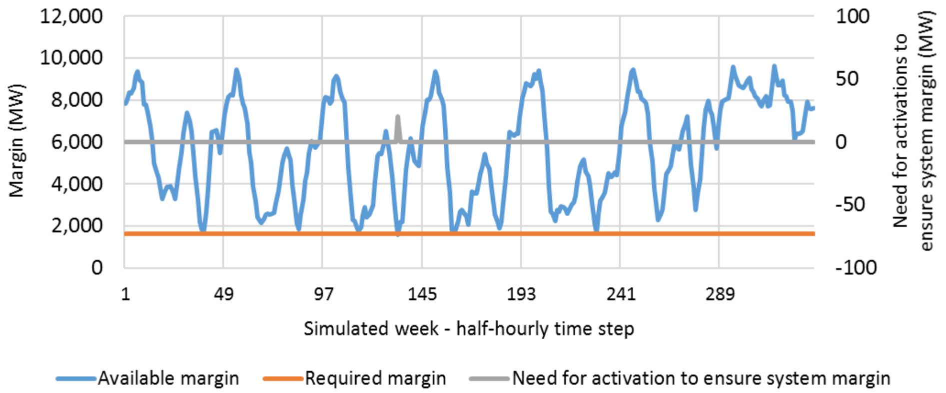

Figure 37: Study of the available and required 30-minute margin as computed 3 hours before the target time step

On these two graphs, it can be seen that the available upward margin is low during peaks of demand and high during off-peak periods. Indeed, plants can highly increase their production during off-peak periods, either because they are offline and can start up or because they do not produce at their maximum level. Moreover, for the margin depicted in figure 36, the available margin is high because the 8-hour maturity enables the TSO to consider the possible modification of the production level of each plant over a long period. Indeed, over 8 hours, plants can always reach their maximum power. In addition, calculating this margin 8 hours before the target time step enables the TSO to consider in the available margin plants with a start-up time strictly lower than 8 hours (i.e. CCGT power plants) and which can be potentially activated later to ensure margin, but without activating them immediately. However, since the required margin is also high for this maturity (the 8-hour maturity represents the highest required margin), the available margin may not be enough. For instance, for the time step 200, the need for activations to ensure system margin can be noticed: 8 hours before the target time step, the TSO requires the start-up of a coal-fired plant.

Figure 37 represents the lowest available margin. Indeed, it combines the 30-minute maturity (which strongly limits the maximum power that each plant can reach over this period) and a calculation performed close to the target time step (3 hours before). Since no power plant can be activated to ensure margin in less than 3 hours strictly, the TSO, unlike the 8-hour maturity, cannot rely on any power plants which can be potentially activated later. However, the required margin is also the lowest in this case. In figure 37, the need to activate a CCGT plant starting up in 3 hours can be noticed.

Figure 38 shows the average number of plants activated by the TSO to ensure upward system margin for each type of power plant and for each maturity for all simulated weeks. Conclusions differ based on the type of weeks. For the winter weeks, activations are mainly done with coal-fired plants for the 8-hour maturity and with CCGT starting in 3 hours for the 3-hour maturity. Indeed, in winter, the required margins are the highest (since they are assumed to increase with the electricity consumption). Moreover, the TSO always waits the last moment to activate these plants. For instance, for the 3-hour maturity, the TSO activates CCGT plants which start in 3 hours instead of coal-fired plants or CCGT plants starting in 4 hours. This solution enables to activate the cheapest plants (CCGT plants are less expensive than coal-fired plants since their technical constraints, in particular the minimum up time, are less stringent). However, for the 8-hour maturity, the TSO has only one solution: activating coal-fired plants.

For the summer weeks (and partly the mid-season weeks), activations are mainly done with CCGT plants starting in 3 hours and for the 30-minute maturity. Indeed, for this low maturity, the available margin provided by each plant is the lowest (production can be modified over 30 minutes only). Although the required margin with a 30-minute maturity is lower than that of other maturities, this does not compensate the sharp decline in the available margin provided by each plant. For instance, modelled nuclear power plants can produce an additional 150 MW over 30 minutes and up to 600 MW over 2 hours on average but the required margin does not change in the same proportions, moving from 2,300 MW for the 2-hour maturity to 1,615 MW only for the 30-minute maturity.

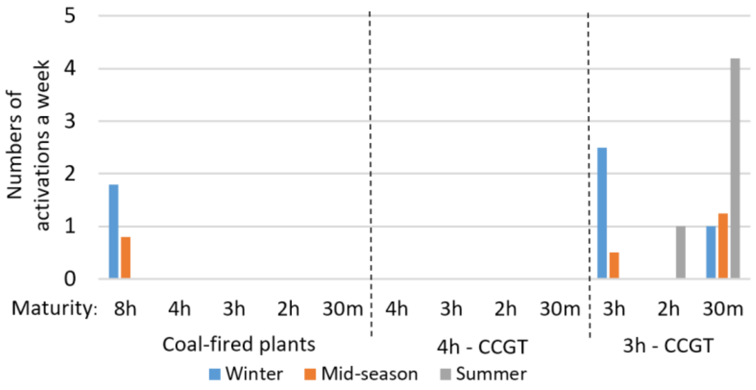

Figure 38: Average numbers of activated plants to ensure system margin for each type of plants, each maturity and each type of weeks

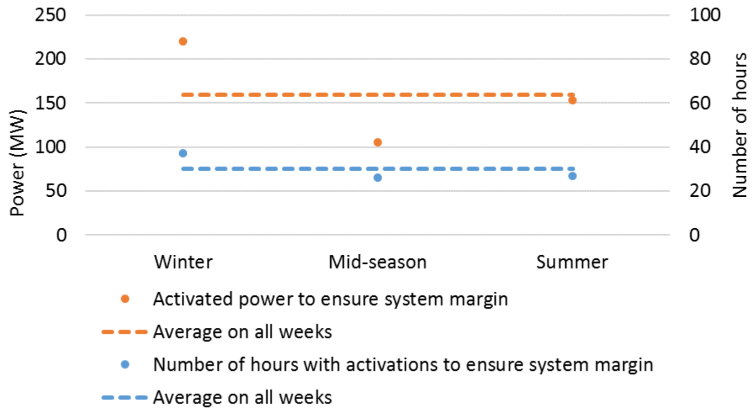

Figure 39: Characteristics of activations to ensure system margin for each type of weeks

Finally, figure 39 shows the average number of hours per week when plants are activated to ensure system margin as well as their average production during these hours. It should be noted that activations involve a limited number of hours (30 hours on average per week) and a limited volume compared to the additional upward reserves procurement in the alternative security model (160 MW vs. 1800 MW). Thus, the energy produced by these activations will have a limited impact on the final production level, as it will be discussed later in the section about the balancing mechanism.

<u>Main results:</u>

- Several activations to ensure system margin are observed for the simulated weeks. They mainly concern coal-fired plants for the 8-hour maturity and CCGT plants whose start up is equal to 3 hours for the 3-hour and 30-minute maturities.

- Moreover, these activations are limited both in volume (on average 160 MW) and in duration (on average 30 hours a week).

4.1.7. Study of the balancing mechanism

In this section, several points are studied and compared between both security models. First, the technologies activated on the balancing mechanism are studied. Then, imbalance settlement prices (ISP) are computed and compared. Finally, a focus is made on the activations to ensure system margin and their impacts on the balancing mechanism in the French security model.

4.1.7.1. Different activated technologies on the balancing mechanism between both security models

Imbalances to be solved by the TSO on this mechanism are determined by:

- The consumption and production forecasts errors between the intraday horizon and the real time, which are considered identical between both security models
- The remaining imbalances of BRPs after the intraday market[97]
- The previous activations to ensure system margin in the French security model
    - Even if these activations are performed for security reasons and not to solve any imbalances, the energy produced by the plants activated by the TSO has an impact on the real-time imbalances that have to be solved on the balancing mechanism.
    - For instance, let us consider a real-time imbalance in a situation without activations to ensure system margin equals to – 400 MW (i.e. 400 MW should be activated upwards). If a 100 MW activation was performed by the TSO before the real time to ensure system margin, it increases the production by 100 MW. Then the TSO has to activate only 300 MW upwards on the balancing mechanism.

[97] These imbalances are most of the time equal to zero in both security models and, when not, their order of magnitude is low compared to the imbalances due to forecasts errors.

  - The impacts of the activations to ensure system margin in the French security model on the quantity to be activated on the balancing mechanism and on the imbalance prices will be studied in a distinct section thereafter.

Among these three sources of imbalances, the first two ones are almost similar between both security models and the order of magnitude of the third one is less significant (volumes activated to ensure system margin are small compared to imbalances due to forecast errors and they only concern a few time steps). Then, imbalances to be solved by the TSO on this mechanism are almost similar between both models.

However, the upward and downward supply bids submitted by BRPs are very different between both security models. Two reasons can explain this:

- The voluntary bids (i.e. bids submitted by plants which are not identified to provide reserves) are different since the production and start-up decisions previously made by BRPs differ between both models (higher production with fossil-fuel plants in the alternative model)
- The bids submitted by plants which are identified to provide RR are different between both security models since a higher level is procured in the alternative model, both upward and downward.

Then, technologies activated to solve imbalances are not exactly the same between both models. The average share of activated energy for each technology and for each direction (upward or downward) are depicted in figure 40 and figure 41 for each type of weeks (to simplify the reading of these graphs, CCGT and coal-fired plants are gathered together).

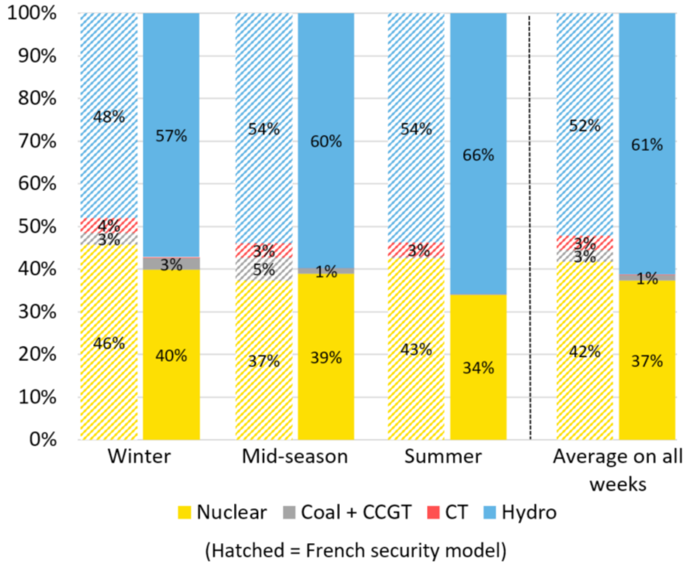

Figure 40: Average share of energy activated upward by technologies for each type of weeks

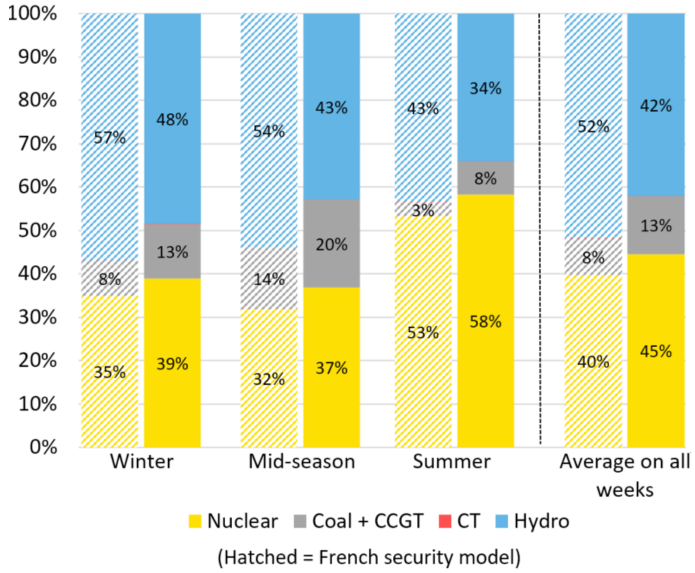

Figure 41: Average share of energy activated downward by technologies for each type of weeks

From these results, the hydroelectric and nuclear plants perform the vast majority of activations, both upwards and downwards and in both security models. It is simply explained by the fact that these technologies produce as base-load or mid-merit production: as a result, they produce most of the time and are then often activated compared to fossil-fuel plants which are less used[98].

[98] Upward activation of nuclear and hydroelectric plants may seem surprising. Two points may explain this:

When comparing activated energy in both security models, the main relevant and interesting differences concern fossil-fuel plants (coal-fired plants, CCGT plants and combustion turbines) and hydroelectric plants. Upwards, in the French security model, the TSO activates larger volumes for fossil-fuel plants, in particular for combustion turbines, for all simulated weeks (on average, fossil-fuel plants activations are about 7 times larger in the French security model) and lower volume for hydroelectric plants. On the contrary, the alternative security model relies more on hydroelectric plants and less fossil-fuel plants are activated upwards[99]. The higher activation of hydroelectric plants in the alternative model is explained by the higher level of bids submitted by procured upward RR. In particular, hydroelectric plants submit on average 1 GW of upward supply bids. Moreover, given their relatively low water value, hydroelectric plants are activated by the TSO before fossil-fuel plants which are more expensive. In the French security model, this volume of hydropower is not available on the balancing mechanism. Indeed, since this volume is not procured by the TSO, BRPs use it to produce before the balancing mechanism. Thus, in real time, hydroelectric plants submit a smaller volume for upward activations. The TSO has to resort to more expensive technologies to solve negative imbalances, such as combustion turbines (which are able to start up in one time step) or coal or CCGT plants previously started up. It explains the higher share of fossil-fuel plants for upward activations in the French security model.

Regarding downward activations, different volumes of activated fossil-fuel plants can also be noticed between both security models. In the alternative one, the share of these technologies is greater than in the French one for all simulated weeks (on average, downward activations on fossil-fuel plants are almost twice higher in the alternative

- During off-peak periods (in particular during weekends), the demand is low and then nuclear and hydroelectric plants do not need to produce at their maximum output. Then, they can provide upward supply bids during these periods.
- During peak periods but also during off-peak periods (in particular during the nights), these plants may have to reduce their production to enable fossil-fuel plants to produce beyond their minimum power. It is particularly true for hydroelectric plants whose production depicted in Figure 35 is not always equal to their maximum output.

[99] The volume of nuclear plants activated upwards can also be different between both security models. However, this difference is mainly explained by the evolution of the water value which can be different in both security models, in particular for the summer weeks. Then, depending on this evolution, it may be cheaper to activate hydroelectric plants upwards than nuclear plants. It then explains the difference in activations of nuclear plants between both models. In any case, these plants having similar variable costs, the use of hydroelectric or nuclear plants to solve negative imbalances will not impact significantly balancing costs, contrary to the greater use of fossil-fuel plants in the French security model.

security model). This difference is also caused by the higher upward RR procurement in the alternative security model and its consequences on BRPs' generation decisions. Indeed, the unavailability of an average 1 GW of hydroelectric plants on the day-ahead market results in the start-up of several fossil-fuel plants (coal-fired and CCGT plants). In particular, these plants are planned to produce during peak hours. Then, during these hours, they are able to submit downward supply bids on the balancing mechanism. Since their variable costs are higher than the water value or the variable costs of nuclear plants, the TSO activates first these bids downwards to solve positive imbalances. In the French security model, fossil-fuel plants are not scheduled to produce or in a lesser extent since BRPs can rely on the entire availability of hydroelectric plants. Then, fossil-fuel plants, since not started up, submit a lower volume of downward bids on the balancing mechanism. That is why the activated volume for these plants is lower in the French security model. To compensate, the TSO activates more bids from hydroelectric or nuclear plants downwards.

4.1.7.2. Study of imbalances settlement prices

The differences in technologies used to perform activations on the balancing mechanism results in different ISPs between both security models. In particular, imbalance prices when the system is negatively imbalanced could be higher on average for the French security model since more expensive plants are activated than in the alternative security model. The next section will study these imbalance prices for both security models.

Since 2017, the French ISP is defined as a single price, i.e. negatively and positively imbalanced BRPs are subject to the same imbalance price (RTE, 2018)[100]. This rule is applied here to define ISP. Moreover, the computation of these prices requires the definition of two additional terms: the balancing trend of the power system and the way imbalances prices are computed (and the way activations to ensure system margin are considered).

[100] Strictly speaking, ISPs are not really defined as a single price since a coefficient k is applied in a different way depending on the imbalances of the BRPs. However, this coefficient is ignored in the modelling to simplify.

4.1.7.2.1. Definition of the balancing trend of the power system

The definition considered by the French TSO is used. The balancing trend of the system is defined by the sum of all capacities activated by the TSO, whatever the reason (RTE, 2018). In particular, activations can be done to solve imbalances or to ensure system margin.

Table 9 illustrates the computation of the balancing trend of the power system for several situations depending on the volume activated to ensure system margin. For all situations, the defined trend of the system corresponds exactly to the opposite of the aggregated imbalances of BRPs. If the sign of the sum of all activated capacities by the TSO is positive (respectively negative), i.e. aggregated imbalances of BRPs are negative (resp. positive), the balancing trend is defined as upwards (resp. downwards).

In particular, the fact of activating bids to ensure system margin, even if it modifies the capacities to be activated on the balancing mechanism, does not modify the trend of the system. BRPs are then confronted with the actual imbalances they create. If they create aggregated negative imbalances, the imbalance prices is always defined based on that volume, independent of the actions of the TSO and whether it activates bids to ensure system margin.

Table 9: Illustration of the computation of the balancing trend depending on the volume activated to ensure system margin

Aggregated imbalances of BRPs	Activations to ensure system margin	Activations on the balancing mechanism[101]	Balancing trend
- 500 MW	+ 200 MW	+ 300 MW	+ 500 MW
+ 500 MW	0 MW	- 500 MW	- 500 MW
+ 50 MW	+ 200 MW	- 250 MW	- 50 MW
-50 MW	+ 200 MW	- 150 MW	+ 50 MW

4.1.7.2.2. Definition of the ISP

In this modelling, ISPs are defined based on the marginal costs of activated plants. (appendix N explains why this solution is chosen whereas the current French ISP is based

[101] Upward activations, which correspond to a production increase, are considered as positive in the modelling. An activation of + 300 MW then corresponds to an upward activation.

on an average weighted cost of activations). ISPs are defined based on the price of the last bid activated to solve imbalances. For instance, if the system experiences an upward trend, ISPs are defined based on the marginal costs of the last activated upward bids.

Moreover, the activations to ensure system margin are considered in the computations of ISPs in a similar way as it is currently done in France (see appendix N). In case of an upward trend, activated bids to ensure system margin are considered at the minimum value between the price they submit and the price of the last activated bid on the balancing mechanism to solve imbalances. Then, in any case, the marginal price remains the same when considering activated bids to ensure system margin and is defined by the most expensive bid activated upwards on the balancing mechanism. In case of a downward trend, activations to ensure system margin are not considered and the price of the least expensive bid activated downwards on the balancing mechanism is considered to define ISP.

For the alternative security model, the same formulae are assumed (but without the consideration of bids activated to ensure margin system).

4.1.7.2.3. ISPs can send wrong incentives to BRPs to be balanced in case of upward trend in the alternative security model

Instead of comparing the level of the ISP between both security models, it is more relevant to compare the spread between the ISP and the day-ahead market for the same time step. In particular, the sign of this spread should be studied as it will mainly influence BRPs' strategy and incentives sent to be balanced. Indeed, the literature suggests that the imbalance price has to be higher (respectively lower) than the day-ahead price in case of aggregated negative (resp. positive) imbalances (Hirth and Ziegenhagen, 2015). Otherwise, BRPs may be incentivized to rely on the balancing mechanism to be balanced which may then jeopardize the security of the system. This situation will be illustrated later.

Then, in the following paragraphs, the sign of the imbalance spread, defined as the ISP minus the day-ahead price of the corresponding half-hour, is studied. This spread is represented for a studied winter week in figure 42. The mean values of these differences for all simulated weeks are also presented in figure 43 and figure 44.

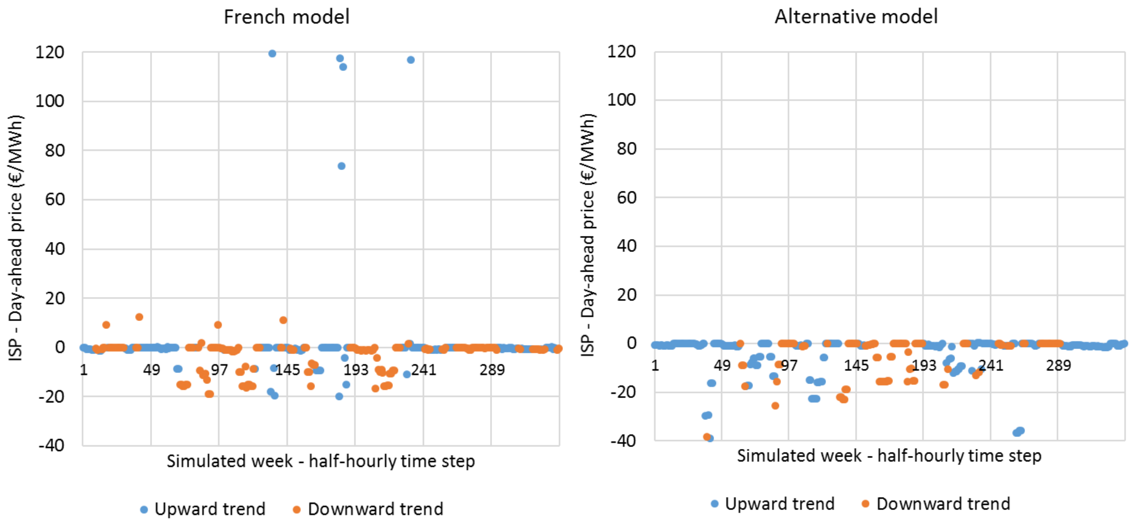

Figure 42: Spread ISP – Day-ahead price for one winter week and for both security models

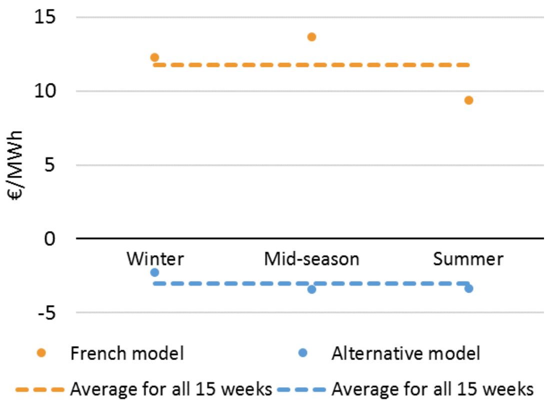

Figure 43: Average spread in case of upward trend for each type of weeks

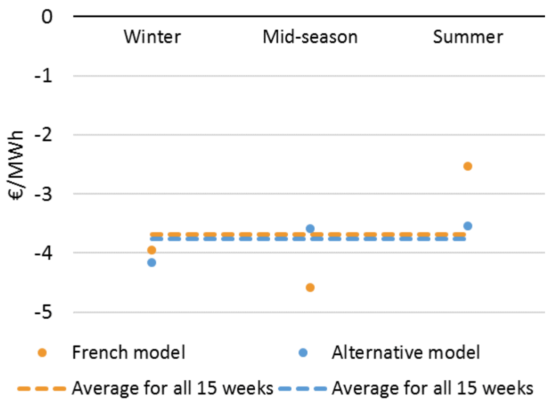

Figure 44: Average spread in case of downward trend for each type of weeks

The spread is studied in details by distinguishing situations where the system is positively imbalanced (downward trend) and situations where it is negatively imbalanced (upward trend).

4.1.7.2.3.1. Study of time steps in case of upward trend

In case of negative imbalances, a negative spread is always observed for the alternative security model on figure 43, which means that the imbalances prices are lower than the day-ahead prices. This is mainly due to additional procurement of upward RR with this security model. Indeed, power plants identified to provide upward RR products reduce the energy they sell on the day-ahead market. When hydroelectric plants are identified to provide these reserves (as it is the case in the alternative model for on average 1 GW), they are no longer available to produce and more expensive bids of fossil-fuel plants are accepted on the day-ahead market which increases the day-ahead price. However, on the balancing mechanism, the hydroelectric plants identified to provide upward RR have to submit upward bids. These bids are submitted to their water value, computed based on a trade-off with the expected day-ahead prices over up to two weeks. In case the system is negatively imbalanced, bids of hydroelectric plants are activated by the TSO before bids of fossil-fuel plants, since the water value is lower than variable costs of fossil-fuel plants. Since hydroelectric plants provide a large volume of upward RR, these bids are often sufficient to solve all negative imbalances. Then, the imbalance price is equal to the water value, which is lower than the day-ahead price defined by bids of fossil-fuel plants. In this case, the spread is negative. This situation only occurs in the alternative security model. Indeed, no hydroelectric plants are identified to provide upward RR in the French security model. On the contrary, instead of hydroelectric plants, the TSO activates more bids of expensive plants (in particular combustion turbines) to solve negative imbalances in the French security model, which results in large positive spreads[102]. That is why, on average, the spread appears to be positive for the French security model whereas the alternative security model experiences a negative spread (cf. figure 43).

A negative spread, i.e. an ISP lower than the day-ahead market, can result in wrong incentives sent to BRPs in case of upward trend. Indeed, if a BRP is negatively imbalanced (i.e. it worsens the situation), the lower price of the ISP may incentivize it to

[102] Some negative spreads are however possible in the French security model. This is notably explained by the fact that bids submitted on the day-ahead market by fossil-fuel plants often include a mark-up above their variable costs to cover their start-up costs. However, on the balancing mechanism, these fossil-fuel plants submit bids at their variable costs only. If they are activated upwards and if they are marginal on both markets, the imbalance price is then equal to their variable costs and then lower than the day-ahead price: a negative spread is possible. However, this is also true for the alternative security model. The French security model is then not worse than the alternative one on this point.

increase its negative imbalances. In that case, they save the day-ahead price and pay a lower price for imbalances. This situation can result in strategy where all BRPs are negatively imbalanced. For a positively imbalanced BRP (i.e. which helps the system to be balanced), since it receives a low price for its imbalances (at least lower than the day-ahead price), it is not incentivized to be positively imbalanced and to help the system. Then, in the alternative security model, a negative spread in this situation may jeopardize the security by increasing the imbalances the TSO has to manage in real time.

This fundamental difference between both security models can be explained by the distortion of the merit order caused by the procurement of additional upward reserves on hydroelectric plants in the alternative model. Theoretically, to avoid distorting the merit order, the cheapest plants should produce on the day-ahead market and more expensive plants should be used to perform upward balancing in real time. This situation is close to what is noticed in the French security model and sends right incentives to market players to help balancing the system, i.e. an ISP higher than the corresponding day-ahead price when the system is negatively imbalanced. On the contrary, in the alternative security model, hydroelectric plants are identified to provide most upward RR. Then, they cannot produce at their maximum output on the day-ahead market but can be used to perform upward balancing in real time: this may lead to a distortion of the ISPs which are lower than the corresponding day-ahead prices. Consequently, it sends poor incentives (or even inefficient) to market players to help reducing the negative imbalances.

4.1.7.2.3.2. Study of time steps in case of downward trend

As for the negative imbalances, the spread is generally equal to zero or very low in case of downward trend. However, when not, it is mostly negative, i.e. the imbalance price is lower than the day-ahead price. Indeed, when day-ahead prices are defined by baseload nuclear plants or mid-merit hydroelectric plants, fossil-fuel plants are not expected to produce or at their minimum output (for instance, during the night). Then, positive imbalances can be solved only by reducing the production of nuclear or hydroelectric plants and the imbalance price is very close to the day-ahead price: the spread is equal (or close) to zero. On the contrary, when day-ahead prices are defined by fossil-fuel plants (during peak periods), these plants produce above their minimum output and can submit downward bids. Then, two situations can be observed regarding downward activations.

Firstly, fossil-fuel plants can be sufficient to solve all positive imbalances. In that case, they define the imbalance price to their variable costs. However, the day-ahead price is usually larger than their variable costs since a mark-up is added. In that case, the spread is negative. Secondly, it is possible that volumes submitted by these fossil-fuels plants on the balancing mechanism are not sufficient to solve all imbalances. Then, the TSO then has to activate bids whose variable costs is lower and the spread is also negative.

Based on values of figure 44, the spread appears to be negative on average in both security models and then the right incentives to help the system to be balanced (i.e. to reduce the positive imbalances) are send to market players through these prices. Both security models are similar on this point. In particular, it should be noted that, contrary to the upward case, the procurement of downward RR in the alternative security model does not distort the imbalance prices, i.e. the spread remains mainly negative. Indeed, these reserves are provided entirely by baseload nuclear plants (see appendix L) and their downward bids would have been available even without procurement. In particular, baseload nuclear plants also submit downward bids in the French security model whereas they are not procured. Then, the procurement of these reserves does not modify the day-ahead prices, the volumes activated downwards on the balancing mechanism and the ISP in case of a positively imbalanced system.

4.1.7.3. Activations to ensure system margin in the French security model can impact ISPs which may send lower incentives to be balanced to BRPs but for a limited number of hours

In this section, a specific study of the impacts of the activations to ensure system margin is carried out. In particular, their impacts on the volume activated on the balancing mechanism (and the related costs) and on the ISP are considered.

4.1.7.3.1. Impacts of activations to ensure system margin on the activations on the balancing mechanism

When activating bids to ensure system margin, the TSO ensures that the system has enough available margin to be able to react in case the largest imbalances occur. However, nothing guarantees that these imbalances will actually happen. Then, the energy produced by plants activated to ensure system margin may be not necessary in real time. However, the TSO cannot cancel the previous activations to ensure system margin and the energy produced by activated plants then modifies the real-time imbalances and the bids the TSO has to activate on the balancing mechanism. In particular, three situations can be distinguished depending on the balancing trend of the system, i.e. the aggregated imbalances of BRPs (as a reminder, energy activated to ensure system margin is not considered to compute BRPs' imbalances). To illustrate them, let us consider a 200 MW activation to ensure system margin. These three situations are (also illustrated in table 9 page 163):

1) If the aggregated imbalances of BRPs are equal to -500 MW, the previous activations to ensure system margin are in the right direction and help to solve imbalances. Then, on the balancing mechanism, the TSO needs to activate 300 MW upwards only.
2) If the aggregated imbalances of BRPs are equal to +500 MW, the previous activations to ensure system margin are in the wrong direction. Then, the TSO should decrease the production by 500+200 = 700 MW on the balancing mechanism, i.e. by a larger volume than without activations.
3) Finally, if aggregated imbalances of BRPs are equal to -50 MW, the TSO should increase the production by 50 MW if no activations to ensure system margin were previously decided. Yet, due to these activations, it increased the production by 200 MW. Then, to have a balanced system, the TSO should reduce the production on the balancing mechanism by 150 MW. In that case, the previous activations to ensure system margin change the direction of the imbalances to be solved on the balancing mechanism (but they do not change the balancing trend which depends only on the aggregated imbalances of BRPs).

In each situation, the previous activations to ensure system margin can either increase or decrease the bids which have to be activated on the balancing mechanism compared to a scenario without any activations to ensure system margin, and then distort the merit order. The costs to solve imbalances created by BRPs can be modified.

To better understand these costs and the impact of activations to ensure system margin on them, a comparison is made with a theoretical scenario for which no activations to ensure system margin are performed but for which all other parameters are the same as in the French security model, in particular the reserves procurement levels. This scenario is purely theoretical since security would not be ensured in this case. To study this comparison, the balancing mechanism is simulated in the same conditions as the for the French security model but without considering the previous activations to ensure system margin. For instance, if the TSO performs a 200 MW activation to ensure system margin, these 200 MW are not produced and considered in the theoretical scenario without activations and then the bids that the TSO has to activate on the balancing mechanism are different.

The costs of plants activated by the TSO and which participate to the resolution of imbalances are compared between each scenario. They can be activations on the balancing mechanism and/or activations to ensure system margin (in which case they may worsen the resolution of imbalances). Considered costs are:

- Costs of plants activated on the balancing mechanism (i.e. their variable costs[103]). These costs are negative in case of downward activations (saved costs).
- Variables costs of plants activated to ensure system margin[104].

Then, the cost differences computed in this section between both scenarios do not correspond exactly to the net costs (or savings) of the activations to ensure system margin since the start-up costs of activation to ensure system margin have to be added (which will be done in the next section). This cost comparison enables to assess whether the activations to ensure system margin decrease the costs of activations to balance the system or not compared to a scenario without activations.

Figure 45 illustrates the differences in activation costs to solve BRPs' imbalances for the fifteen simulated weeks and for the three situations mentioned previously. These differences are computed as: Activations costs in the scenario with activations to ensure system margin – activations costs in the scenario without activations to ensure system

[103] Except for combustion turbines which can start up in 30 minutes and then submit a start-up bid and for which start-up costs are also considered.
[104] In particular, their start-up costs are not considered in this comparison. Indeed, they encompass several time steps and the repartition of fixed start-up costs for each time step can be difficult. Then, in this comparison, it is assumed that the start-up decisions of activated plants to ensure system margin are already made and the comparison is only performed between the production costs of the plants (without start-up costs) and the production costs of bids activated on the balancing mechanism.

margin. A positive difference then means that the activations costs are higher with activations to ensure system margin than without. Based on these results, it appears that:

- For the situation where the balancing trend is larger than the energy produced by activations to ensure system margin, the previous activations to ensure system margin tend to decrease the costs of activations to solve imbalances compared to a scenario without activations by on average 51,000 € per week. Indeed, the energy produced by plants previously started up to ensure system margin enables the TSO to avoid activating expensive bids on the balancing mechanism, such as combustion turbines as it is the case in the scenario without activations to ensure system margin.
- For the situation where activations to ensure system margin are in the wrong direction, previous activations to ensure system margin always result in an additional cost to solve imbalances which is about 24,000 € per week. As the energy produced by plants previously started up to ensure system margin is not necessary to solve imbalances, the TSO has often to decrease the production of cheaper plants. Indeed, the TSO cannot decrease the production of plants activated to ensure system margin since they produce at their minimum value. Then, the TSO has often to decrease the production of nuclear or hydroelectric plants. It means that the activated CCGT or coal-fired plants produce instead of baseload or mid-merit plants, which results in an additional cost.
- Regarding the last situation where the previous activations to ensure system margin change the direction of the imbalances to be solved on the balancing mechanism, no clear conclusion can be drawn (the average difference is much lower and its sign differs based on simulated weeks).

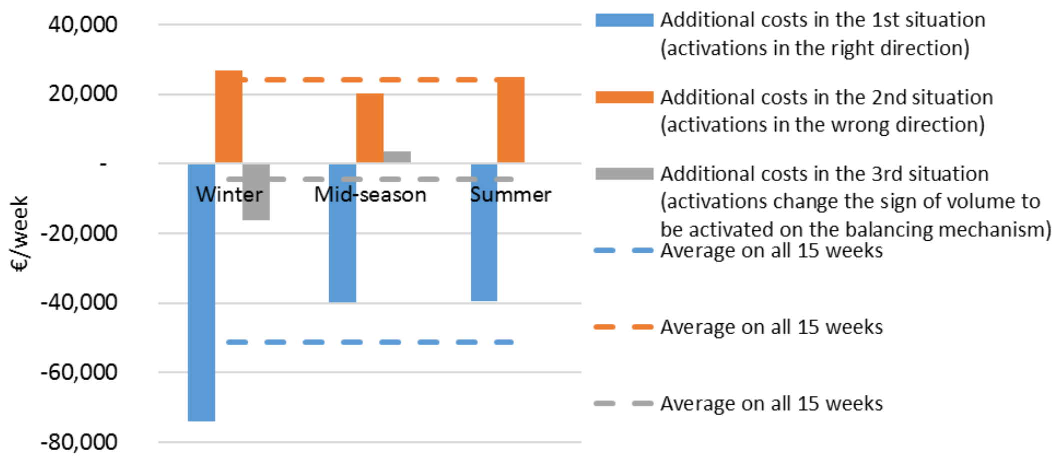

Figure 45: Average impacts of activations to ensure system margin on balancing costs for each type of weeks

Then, it appears that the activations to ensure system margin can change the technologies activated on the balancing mechanism and then modify the balancing costs. This modification can lead to different ISPs as it will be studied in the following section.

4.1.7.3.2. Impacts of the activations to ensure system margin on ISP

The fact that different technologies are activated on the balancing mechanism thanks to (or due to) the previous activations to ensure system margin may modify the ISP compared to a scenario without activations. For instance, if activations to ensure system margin enable to avoid activating combustion turbines, ISP should be lower with activations than without for the same balancing trend. To verify this, ISPs are computed for the theoretical scenario mentioned previously and compared with ISPs computed for the French security model[105]. Figure 46 illustrates these differences for the same winter week as previously and figure 47 presents the average differences for the fifteen simulated weeks. In both cases, the differences for upward and downward trends are distinguished and are depicted only for hours with activations to ensure margin system[106]. The

[105] The day-ahead price is the same in both scenarios; thus, the imbalance spread only depends on ISP. Moreover, since the activations to ensure system margin do not modify the balancing trend, the same formula is used to compute the ISP for each time step for both scenarios: only the activated bids on the balancing mechanism differ.

[106] ISP are the same for hours without activations to ensure system margin since the same bids are activated on the balancing mechanism.

difference is computed as: ISP in the scenario with activations to ensure system margin - ISP in the scenario without activations to ensure system margin.

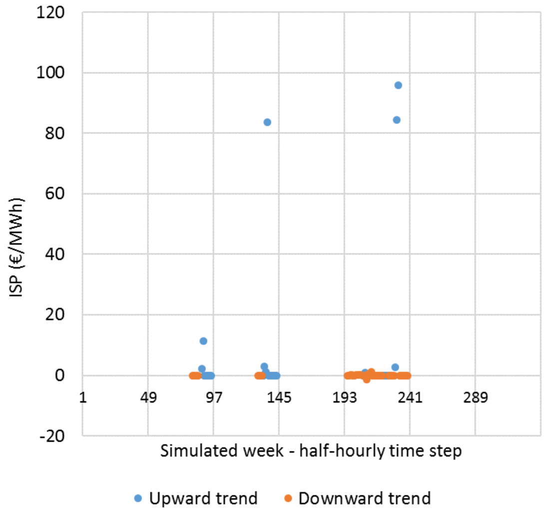

Figure 46: ISP difference with and without activations to ensure system margin for one winter week

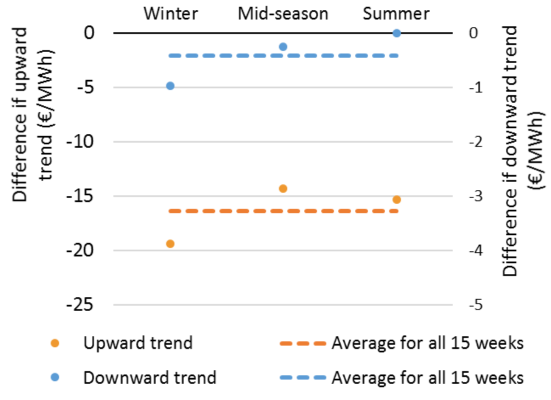

Figure 47: Average differences in ISP with and without activations to ensure system margin for each type of week

Most of the time, ISPs are the same for both scenarios. It means that the same plant is marginal with or without activations to ensure system margin. This situation is possible since these activations concern a small volume (around several hundreds of MW). Therefore, differences in activated quantity on the balancing mechanism are small and the same plant may define the marginal price in both scenarios. However, for hours when ISPs are not the same, it appears that:

- In case of upward trend, ISPs are reduced when activations to ensure system margin are performed by on average € 16.3/MWh. Indeed, these activations enable to reduce the use of expensive power plants (in particular combustion turbines). Marginal bids are then less frequently defined by these expensive plants in the scenario with activations to ensure security model[107].
- In case of downward trend, ISPs are also reduced when activations to ensure system margin are performed by on average € 0.4/MWh. Indeed, since more bids are activated downwards to compensate the production of plants activated to

[107] Moreover, since bids submitted by combustion turbines are very high (up to €400/MWh) compared to bids submitted by other plants, the ISP can increase largely if these bids are activated: that is why the average difference can be high even if the difference is equal to zero most of the time.

ensure system margin, the price of the marginal bid is lower than in the scenario without activations[108].

As a result, it appears than on average the ISP is reduced in the French security model during hours with activations to ensure system margin compared to a scenario without activations. Then, it may modify the behaviour of BRPs. To illustrate that, let us consider a BRP which anticipates an ISP of €20/MWh. It then optimizes its imbalances based on that expected cost. For instance, let us consider that it does this optimization 8 hours before the real time and that its optimized imbalance within its portfolio is zero. To compute the need of activations to ensure system margin 8 hours before the real time, the TSO considers the forecast imbalances of BRPs. In particular, the TSO anticipates that the aforementioned BRP is correctly balanced, and then that it does not decrease the available margin. Moreover, let us consider that the TSO needs to perform an activation to ensure system margin 8 hours before the real time. In that case, the BRP may anticipate that this activation will lower the ISP. Consequently, it may change its imbalances since the cost of being negatively imbalanced will be lower. This modification is still possible since 8 hours before the real time, BRPs can participate to the intraday markets (gate closure is often one hour or 30 minutes before the real time). Then, the optimization of the BRP may change and it may decide to be negatively imbalanced, for instance by 100 MW. This change may decrease the available margin of the system by 100 MW. The volumes activated by the TSO to ensure system margin may then be lower than what it really needs and the security can be jeopardized.

Then, the decrease of ISP when performing activations to ensure system margin may incentivize BRPs to be more negatively imbalanced. This may change the volume needed to ensure security and increase the imbalances the TSO has to deal with in real time. However, studying the consequences on BRPs' behaviour would require an in depth study to consider properly the reactions of BRPs to activations to ensure margin system and the evolution of the available and required margins following these reactions. In any case, this risk seems limited to hours when the TSO performs activations to ensure system margin and not to all hours. Risks of distortion of the ISP in the French security model

[108] However, the average difference is lower for the downward trend than for the upward one. Indeed, nuclear or hydroelectric plants are often marginal in case of downward trend and their variable costs and water value are very close. Activating a lower bid in the scenario with activation to ensure system margin then does not result in a large difference compared to the scenario without activations.

seem less concerning than in the alternative security model where it concerns all hours (since an additional procurement level is needed for all hours) and where the spread between ISP and day-ahead price can be negative in case of upward trend (even if it is reduced in the French security model, this spread remains positive and sends incentives in the right directions to BRPs).

Main results:

- To solve negative imbalances, the French security model activates more bids of fossil-fuel plants than the alternative security model (which can rely on bids submitted by hydroelectric plants identified to provide upward RR). Downwards, the alternative security model tends to activate more fossil-fuel plants since they are more likely to produce (and then to submit downward bids) in this model than in the French one.
- These differences in activated technologies result in different ISPs. In particular, it should be mentioned that, on average for the simulated weeks, the spread ISP - day-ahead market is negative in case of upward trend in the alternative security model. This is due to the distortion of the merit order caused by hydroelectric plants identified to provide upward RR. This negative spread can send wrong incentives to BRPs in order to be balanced and then jeopardize the security. For the French security model, this spread is on average positive and then right incentives are sent to BRPs.
- Regarding the spread in case of downward trend, both security models experience a negative spread: right incentives are then sent to BRPs. In particular, in the alternative security model, the absence of distortion (compared to the upward trend) is explained by the fact that plants identified to provide downward RR (namely nuclear plants) do not distort the merit order as it is the case with hydroelectric plants identified to provide upward RR.

- Finally, the impacts of the activations to ensure system margin on the volume activated on the balancing mechanism in the French security model are studied. These impacts depend on the final balancing trend of the system. Previous activations to ensure system can either reduce the balancing costs in case of upward trend (they enable to avoid activating expensive plants like combustion turbines) or increase them in case of downward trend (in this case, the energy produced by plants activated to ensure system margin is not necessary to balance the system and cheaper technologies should be activated downwards). The impacts on technologies activated on the balancing mechanism result in different ISPs when activations to ensure system margin are performed. On average for the 15 simulated weeks, ISPs in case of upward trend tend to be reduced when activations to ensure system margin are performed. This reduction may incentivize BRPs to be less balanced and then jeopardize the security. However, this risk seems less concerning than the distortion of ISPs for the alternative security model since they are limited to a few hours only.

4.2. Study and comparison of social welfare in both security models

4.2.1. Components used to compute social welfare

In order to compare the impacts of each security model on the power system from an economic point of view, social welfare is considered for each simulated week. Since power consumption is considered as inelastic and is the same in both security models, the comparison of social welfare can be computed based on:

1) The production costs of dispatchable thermal power plants (nuclear, coal-fired, CCGT plants and combustion turbines[109]), i.e. their variable production costs and their start-up costs. Within this component, the costs of unsolved imbalances after the balancing mechanism are also considered. Indeed, it is sometimes impossible for the TSO to balance the system using bids submitted on the balancing mechanism. In

[109] Since productions from non-dispatchable technologies (wind, PV…) are the same between both security models, there are not valued in the computation of social welfare.

the simulated weeks, it only occurs for the resolution of negative imbalances (i.e. the TSO cannot ask enough plants to increase their production) but it is very uncommon (only for one time step and for 30 MW on all simulations). This situation can happen in the simulations because of the restrictions imposed on supply bids made on the balancing mechanism[110]. In reality, this situation is unlikely because the TSO has many solutions (demand response, interconnections, complex bids of BRPs to be used for several time steps), which are not considered in the modelling, to solve the remaining imbalances. Consequently, the existence of unsolved imbalances in the modelling does not mean effective rolling blackouts. However, these unsolved imbalances occurring in the simulation have to be valued to properly compare both models. A fictive technology is then considered to solve then. A conservative value of 600 € / MWh is chosen to value this technology[111].

2) The valuation of the remaining water reservoir at the end of the simulated week at the last water value computed in the modelling. Indeed, it is likely that the reservoir level is not zero at the end of the first week and hence must be valued.

The quantities used to compute and compare the welfare for each security models are presented and analysed thereafter.

4.2.1.1. A higher final production with coal-fired and CCGT plants in the alternative model

The final production (i.e. after the activations on the balancing mechanism) of the dispatchable thermal and hydroelectric plants is presented in figure 48 for one winter week for both security models (one mid-season week and one summer week are also

[110] In particular, bids do not have to modify their generation over several time steps if accepted, which reduces supplied volumes.

[111] To define the costs of this technology, an analysis of the daily upward supply curves submitted on the French balancing mechanism in 2015 is carried out (data available on the RTE site). Through these values, it can be seen that upward bids with prices up to 600 € / MWh are possible. These bids may represent technologies whose activation is very expensive such as demand response. Then, it is assumed that unsolved imbalances can actually be solved using a fictive technology whose variable cost is € 600/MWh. Given the activations costs of demand response available in the literature, this assumed value seems to be conservative. For instance, a study realized by E-CUBE Strategy Consultants for the French regulator mentioned a variable cost of about 300€/MWh (http://www.cre.fr/documents/consultations-publiques/principes-structurant-le-projet-de-proposition-de-decret-relatif-a-la-valorisation-des-effacements-de-consommation-d-electricite-sur-les-marches-de-l-electricite-et-le-mecanisme-d-ajustement/consulter-l-annexe-2-etude-des-avantages-que-l-effacement-procure-a-la-collectivite)

depicted in appendix O; their interpretations are very similar to the winter week)[112]. As a reminder, the charts begin on Monday.

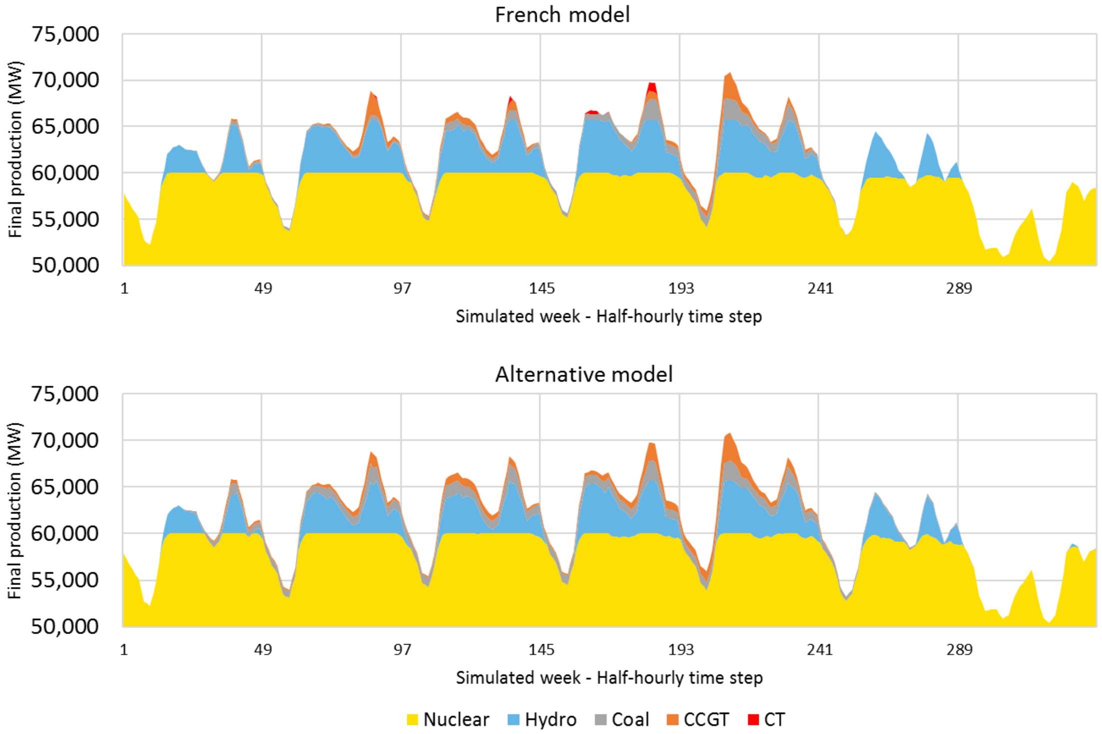

Figure 48: Final production for one winter week and for both security models

To facilitate the comparison of the production between both security models, the production difference is depicted for the corresponding simulated week in figure 49 (one mid-season and one summer weeks are depicted in appendix O). The difference is computed as: Production in the French security model – Production in the alternative security model. Moreover, the average production difference are presented in figure 50 for the fifteen simulated weeks. Within these figures, production is gathered in three groups[113]: 1) nuclear and hydroelectric plants, 2) coal-fired and CCGT plants and 3)

[112] For this week, there is no use of the fictive technology to solve any remaining imbalances.
[113] Indeed, comparisons for each technology between both security models can be complex to interpret. For instance, in the alternative model, BRPs have to produce a large volume with fossil-fuel plants. They may then prefer producing this volume with coal-fired plants since these plants have a higher maximum output and lower variable costs than CCGT plants. On the contrary, in the French security model, BRPs have to produce a lower volume with fossil-fuel plants. They may prefer producing it with CCGT plants whose maximum output is lower. Then, the direct comparison between coal-fired and CCGT plants may be complicated and it is more relevant to compare the sum of both productions. Moreover, a possible trade-off is possible between the production with hydroelectric plants and with the most expensive nuclear plants depending on the evolution of the water value, which can be slightly different between both security models (cf. Part I.4.2.1.2). Then, the strict comparison of production with nuclear plants and hydroelectric plants

combustion turbines and the fictive technology. Activations to ensure system margin in the French security model are also depicted in figure 49.

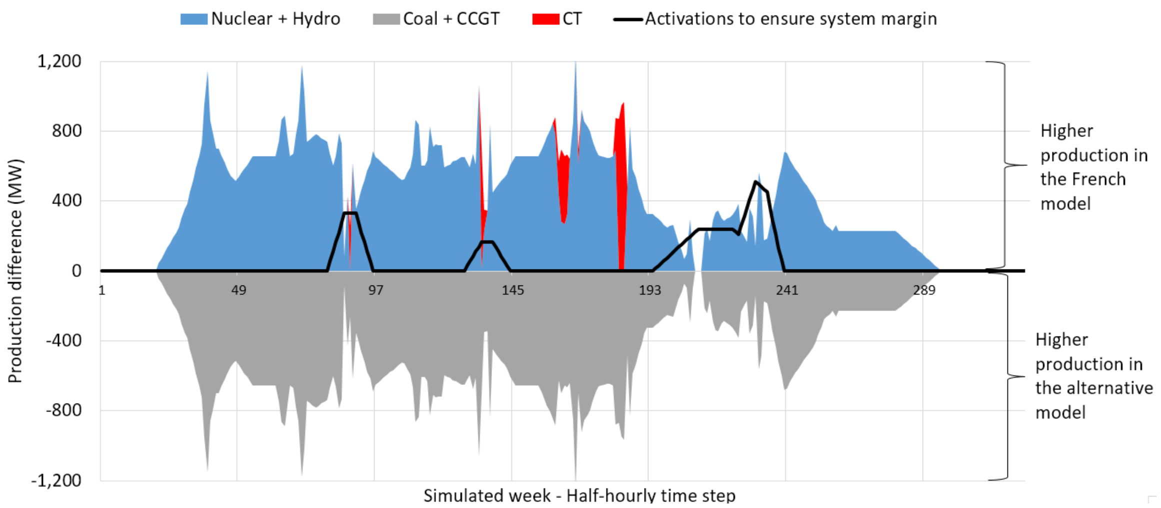

Figure 49: Production difference between both security models for one winter week

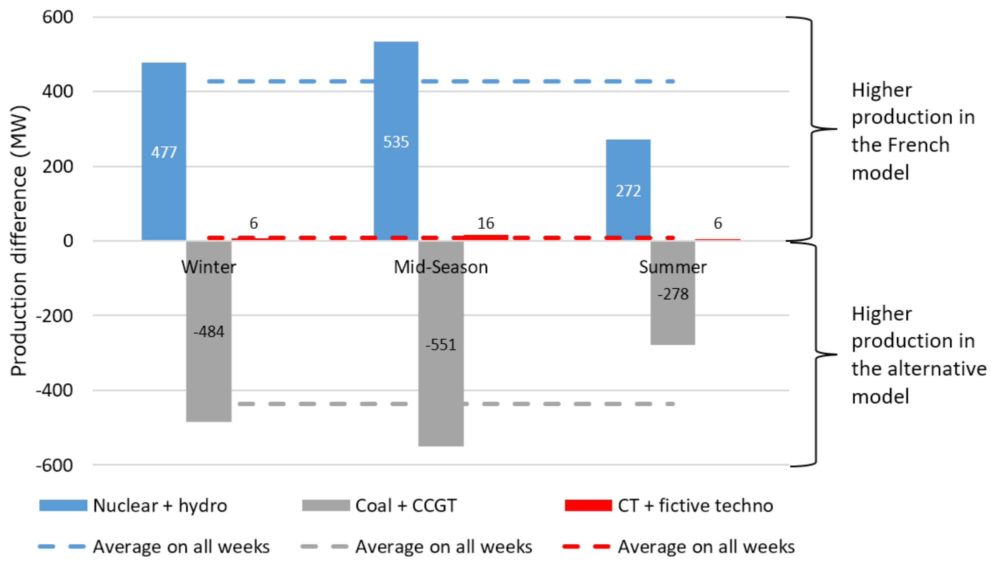

Figure 50: Average production difference between both security models for each type of week

Based on these graphs, it appears that BRPs produce more with coal-fired and CCGT plants in the alternative security model for almost all time steps (the additional production is on average equal to 436 MW). This is due to the additional procurement of upward RR

between both security models makes less sense and it is more relevant to compare the sum of both productions.

and the need to produce with fossil-fuel plants to replace the non-production of hydroelectric plants during peak periods which are identified to provide most upward RR. Moreover, this larger production with coal-fired and CCGT plants can also be noticed during off-peak periods in figure 49. Indeed, due to technical constraints, BRPs prefer (or have to) keeping these plants online during off-peak periods (in particular during the night) to shutting them down. Thus, they have to decrease the production of cheap nuclear plants to be balanced. On the contrary, in the French security model, BRPs can produce with hydroelectric plants during peak periods and do not have to start up fossil-fuel plants (or in a lower extent) to supply demand. Moreover, in the French security model, during off-peak periods, BRPs do not have to reduce the production of baseload plants like nuclear plants to compensate the production of coal-fired or CCGT plants. Then it explains why, for most time steps, nuclear and hydroelectric plants produce more in the French security model (on average 428 MW) and why coal-fired and CCGT plants produce more in the alternative security model, both during peak and off-peak periods.

The differences can be zero for some time steps, in particular during weekends (or for some nights during the summer week, cf. appendix O). Indeed, during these hours, the low demand can be covered almost entirely by nuclear plants and hydroelectric plants produce well below their maximum output. Then, reducing bids submitted by hydroelectric plants identified to provide upward RR in the alternative security model does not necessary result in the start-up of fossil-fuel plants. It then explains why there is no difference between both models for these hours.

Moreover, in the French security model, the TSO may need to resort to expensive technologies (such as combustion turbines) on the balancing mechanism to solve negative imbalances. In the alternative security model, the TSO can use the large volume of procured upward RR provided by hydroelectric plants to solve these imbalances. It explains the difference regarding the production of combustion turbines. However, this difference concerns few time steps only and a small volume (the average difference is about 9 MW).

Finally, the impact of activations to ensure system margin can be noticed with the black curve in figure 50. These activations increase the production of coal-fired or CCGT plants in the French security model. Nevertheless, most of the time, even with these activations, the increased production of coal-fired or CCGT plants in the French security model does not offset the additional production of these plants in the alternative security model due to the additional procurement (for instance for the activations for the winter week depicted in figure 49). For other time steps, it is possible that the activations result in a larger production of coal-fired and CCGT plants for the French security model (for instance for the summer week at the end of the second day, depicted in appendix O) but for a few hours only.

In particular, through these results, it appears that the average production difference between both models is not equal to the additional RR procured in the alternative model, namely 1.8 GW. Indeed, first of all, about 400 MW are provided by offline combustion turbines without distorting the merit order since these plants are never identified to produce (or as a last resort). Among the remaining 1.4 GW, about 330 MW are provided on average by fossil-fuel plants. As peak technologies, providing these reserves with these plants do not really impact the merit order and do not modify the decisions production. However, since these plants are not flexible, they cannot provide a large volume: their associated opportunity costs are high since they generally reflect their start-up costs and it is cheaper to provide reserves with hydroelectric plants. Then, hydroelectric plants, which are highly flexible, are identified to provide the remaining level of reserves, i.e. on average 1 GW.

Nevertheless, it should be noted that the alternative security model does not result in an increase of production from coal-fired and CCGT plants by 1 GW and a decrease of hydropower production by the same amount (the average difference is “only” about 400 MW). Three main points explain that:

- Even if they are not available on the day-ahead market and on the intraday market, the 1 GW of procured hydroelectric plants in the alternative security model can produce on the balancing mechanism in case of negative imbalances. In the French security model, since these plants already produce at their maximum output most of the time before the balancing mechanism, fossil-fuel plants should be activated upwards. Final production differences between both security models are then reduced compared to differences before the activations on the balancing mechanism.

- The impacts on production decisions of the additional procurement is reduced during off-peak periods, in particular during the weekends or during the summer week. Moreover, even if the additional procurement can result in the increase of production of fossil-fuel plants during the nights in the alternative security model, these plants produce at their minimum level and then well below the level of 1 GW.
- Finally, in the French security model, some activations to ensure system margin are performed on fossil-fuel plants which reduces the average difference between both security models.

As a result, the average production difference between both security models is well below the additional upward RR that mid-merit hydroelectric plants have to produce in the alternative security model (namely about 1 GW on average). However, for some hours, in particular for peak hours when the system is positively imbalanced, it is possible to notice this large difference (for instance at the end of the first day or in the middle of the second day in figure 49). Then, during these hours only, the additional procurement of upward RR results in a large production decrease of about 1 GW for hydroelectric plants and an increase of production from fossil-fuel plants for the same volume. Differences in production costs are then important during these hours.

Main results:

- Nuclear and hydroelectric plants produce more in the French security model (on average 430 MW) than on the alternative security model which relies on CCGT and coal-fired plants to produce instead. This difference is explained by the additional procurement of upward RR and the related production decisions on coal-fired and CCGT plants in the alternative security model.
- However, it should be noticed that for several reasons this average production difference between both security models is well below the additional upward RR that mid-merit hydroelectric plants have to produce in the alternative security model.

4.2.1.2. The lower production of hydroelectric plants in the alternative plants translates into a higher valuation of the remaining water reservoir

The evolutions of the average water reservoir level and the average water value for BPRs with dispatchable hydroelectric plants are illustrated in figure 51 and in figure 52 for a winter week (results for one summer and one mid-season weeks are depicted in appendix P and are close to those for the winter week).

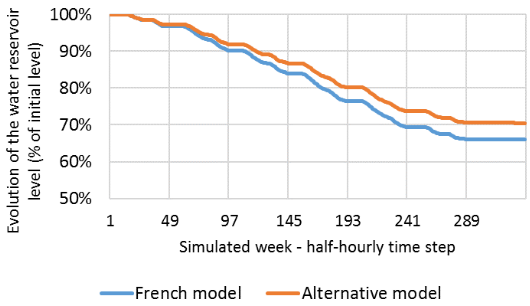

Figure 51: Evolution of the water reservoir level for one winter week

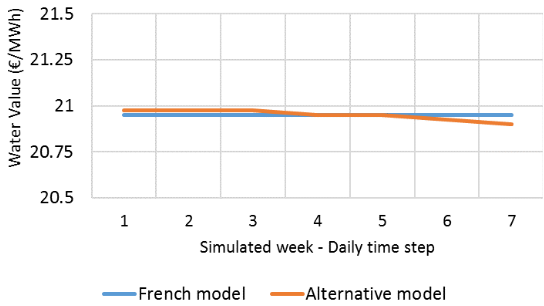

Figure 52: Evolution of the water value for one winter week

The water reservoir level is higher in the alternative security model than in the French one, which means that hydroelectric plants produce less in the alternative security model. This is mainly due to the additional provision of upward RR with hydroelectric plants. The TSO may require these reserves to produce on the balancing mechanism. However, their activations are not certain since they depend on the sign of the imbalances to be solved (if the system is positively imbalanced, hydroelectric plants are not activated to increase their production). It then leads to a slightly higher hydraulic reservoir level at the end of the week in the alternative security model. This lower use of the water reservoir results in a slightly lower water value in the alternative model. Moreover, water values in both security models remain high compared to the variable costs of nuclear plants[114]. Possible trade-offs between productions with the most expensive nuclear plants and with hydroelectric plants are then limited. Except for a few nuclear plants at the end of the simulated week, nuclear plants are always cheaper than hydroelectric plants.

[114] The variable cost of the most expensive nuclear plant is € 21 / MWh.

For this winter week (as for other weeks – cf. values of table 10 in the next section), the remaining water reservoir is then more valued in the alternative security model than in the French one (since the remaining reservoir level is higher and the water value at the end of the week is similar). It compensates partially the higher production costs with expensive fossil-fuel plants due to the upward RR procurement.

Main results:

- Due to the procurement of additional upward RR, the alternative security model tends to produce less with hydroelectric plants than the French one. Consequently, the remaining water reservoir is more valued in the alternative security model than in the French one.

4.2.2. Based on studied weeks, the French security model results in a higher social welfare than the alternative security model

Following the study and comparisons of its different components, social welfare is studied in this section. More precisely, the total costs for the system are computed, namely production costs (variable and start-up costs) + cost of the fictive technology – value of the remaining water reservoir. The aim is therefore to have the lowest possible costs for the system. Moreover, since supplied demand is the same for both security models for each week, these costs can be compared directly between them. The results for each simulated week are presented in table 10 and the difference between both security models in figure 53.

Table 10: Production costs and value of the remaining water reservoir for each studied week and both security models (in € millions)

		Winter weeks					Mid-season weeks				
French model	Prod. costs	189.53	189.49	186.94	189.13	188.76	171.63	168.19	168.19	168.11	171.61
	Value Remaining reservoir	14.22	14.69	14.27	14.56	14.42	13.75	13.72	14.28	14.33	13.61
Alternative model	Prod. costs	190.73	190.72	188.34	190.47	190.16	172.91	169.81	169.23	169.82	172.86
	Value Remaining reservoir	15.13	15.40	14.97	15.22	15.05	14.44	14.64	14.98	15.14	14.42

		Summer weeks				
French model	Prod. costs	137.73	137.48	137.89	137.97	138.21
	Value Remaining reservoir	13.70	13.35	14.03	14.36	13.96
Alternative model	Prod. costs	138.70	138.70	138.89	139.26	139.05
	Value Remaining reservoir	14.28	14.13	14.48	14.94	14.63

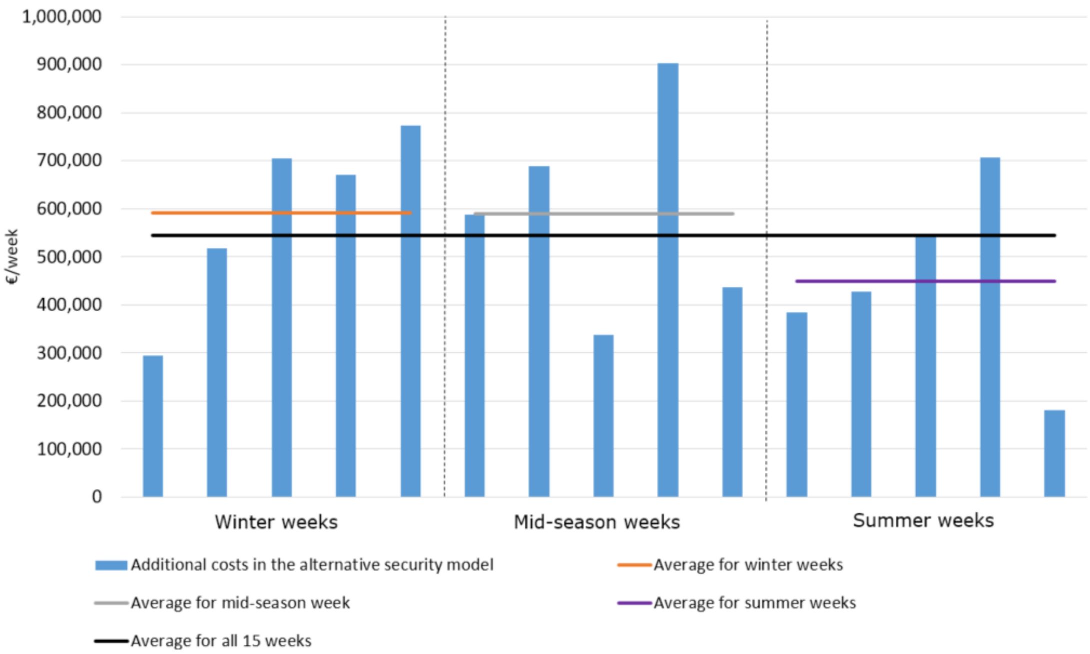

Figure 53: Difference in costs between both security models for all simulated weeks

For each simulated week, the alternative security model leads to an additional cost of production compared to the French security model. The additional cost varies between around € 180,000 for a summer week to almost € 900,000 for a mid-season week. On average, over the fifteen studied weeks, the alternative model leads to additional production costs of around € 545,000 per week. This difference represents on average 0.3% of the production costs considered for the French security model. This small proportion is explained by the fact that the main difference between both security models (mainly the additional upward RR procurement in the alternative model) represents only a small volume compared to the total production (1.8 GW compared to more than 50 GW): it is therefore relevant that the impacts of this difference between both security models are small compared to the total cost of production. Moreover, even if it is not possible to conclude, based on these fifteen weeks only, on the exact annual cost of introducing an alternative security model compared to the French security model[115], it is relevant to conclude that, in the case of the French power system, the alternative security model would lead to higher production costs, of around tens of millions of euros, and then a lower social welfare than the French security model.

It can also be observed that the additional cost between both security models may vary considerably depending on the simulation, and then depending on consumption forecasts and their consequences on the decisions of BRPs and the TSO. For instance, wrong forecasts can impact the number of activations to ensure system margin in the French security model (and then its costs). They can also affect the use of combustion turbines on the balancing mechanism to solve negative imbalances for the French security model[116]. Finally, forecast errors can also increase the number of required start-up of coal-fired or CCGT plants, in particular in the alternative model[117]. In any case, the French security model always appears less expensive than the alternative one.

[115] In particular, it would require to study weeks with a higher demand but also other scenarios of residual consumption.

[116] If negative imbalances appears during peak hours, the French security model tends to rely on combustion turbines to balance the system, which increases its production costs whereas the alternative security model can rely on cheaper activations (in particular the procured RR with hydroelectric plants).

[117] For instance, if the consumption is overestimated on the day-ahead market, more bids of fossil-fuel plants will be accepted, in particular in the alternative model. Then, during the rescheduling stage, BRPs will tend to start up these plants to avoid being negatively imbalanced. However, once this decision has been taken, it cannot be cancelled. In particular, these started plants have to produce (at least at their minimum output) even if BRPs realize they overestimate the demand on the intraday horizon.

To better explain these different additional costs between both security models, it is possible to compare them with a theoretical model where the procurement level is the same as in the French security model and where no activations to ensure system margin are possible (cf. table 11). In this model, the security would not be ensured since the TSO cannot procure additional reserves (as in the alternative security model) nor activate bids to ensure system margin (as in the French security model). The costs of introducing one of both security models can then be computed compared to this reference model.

Table 11: Definition of the reference model

	Activations to ensure system margin	Additional procurement of RR	Security ensured?
Reference model	NO	NO	NO
Solution #1: French security model	YES	NO	YES
Solution #2: Alternative security model	NO	YES	YES

Costs of ensuring security thanks to activations to ensure system margin

The costs of ensuring the security thanks to activations to ensure system margin compared to the reference model can be approximated by the start-up costs of plants activated to ensure system margin and the impacts of these plants activated to ensure system margin on the balancing mechanism compared to the situation without activation to ensure system margin, as studied in the section 4.1.7.3.1. Figure 54 illustrates the net costs of introducing activations to ensure margin to guarantee security for the fifteen simulated weeks. On average, this introduction is costly but the average is low (about € 55,000 per week). The net costs of activations to ensure system margin are due to the distortions of the merit order caused by the imposed and expensive production of activated plants whereas the system does not need it to be balanced most of the time. This imposed production tends to increase the production costs (in particular due to their start-up costs) but may also, for some hours, reduces the balancing costs by avoiding resorting to expensive combustion turbines to solve negative imbalances.

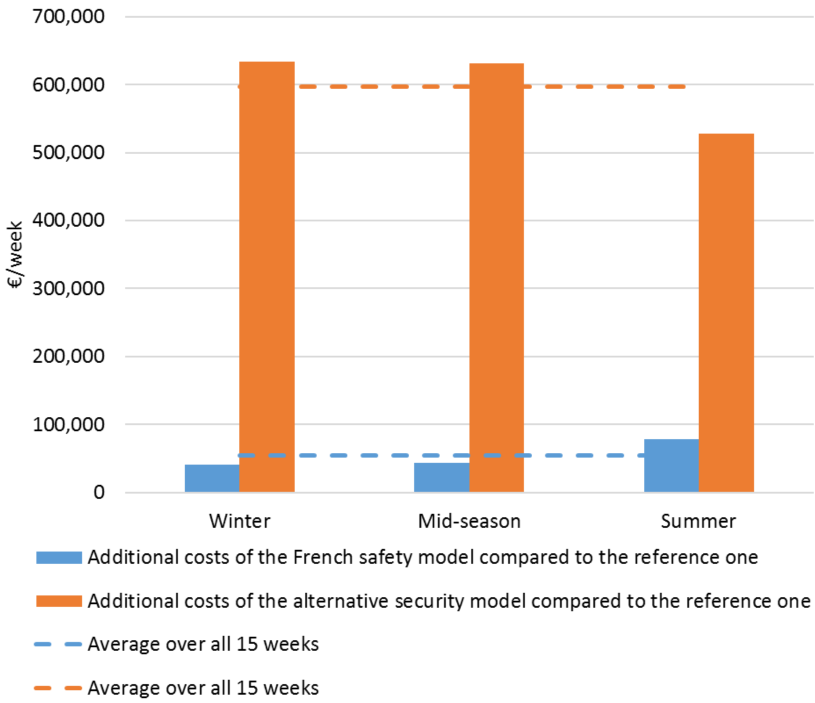

Figure 54: Additional costs of both security models compared to the reference model for each type of week

Costs of ensuring security thanks to additional procurement of RR

Costs of ensuring the security thanks to the procurement of additional RR compared to the reference model can be approached based on previous results[118] and are depicted in figure 54. Over the fifteen studied weeks, the average additional costs of ensuring security thanks to the additional procurement of RR (compared to the reference model) is about € 600,000 per week.

These additional costs are mainly explained by the reduction of the production of hydroelectric plants on the day-ahead and intraday markets due to the larger upward RR procurement. Its results in the starts up of several fossil-fuel plants, which then have to produce both during peak and off-peak hours. Nevertheless, the additional costs of the alternative security model are reduced based on two main points. First, the alternative security model can activate cheaper upward plants (upward RR provided by hydroelectric

[118] Since the cost difference between, on the one hand, the reference model and the French security model and between, on the other hand, the French security model and the alternative security model are known, it is possible to approximate the costs of the alternative security model compared to the reference model.

plants) on the balancing mechanism[119]. Moreover, the lower use of hydroelectric plants in the alternative security model leads to a higher valuation of the remaining water reservoir (see table 10). However, this valuation is done at a low price (around € 21 / MWh) reflecting the fact that hydroelectric plants are used as mid-merit production, whereas fuel-fossil plants used to produce instead of the hydroelectric plants have a variable cost greater than € 30 / MWh. Consequently, valuation of the unused water reservoir in the alternative security model does not offset the cost of the plants used to replace production from hydroelectric plants.

Based on this comparison, it then appears that ensuring the security using activations to ensure system margin and a lower reserve procurement level result in lower production costs and then a higher social welfare than ensuring the security thanks to a high procurement level.

Main results:

- Based on the fifteen studied weeks, the alternative model leads to additional production costs of around € 545,000 per week. This is explained by the larger production of coal-fired and CCGT plants instead of cheaper hydroelectric plants (which are identified to provide upward RR) in the alternative security model.
- In particular, it appears that the costs of ensuring a sufficient level of reserves in real time thanks to activations to ensure system margin is low (on average € 55,000 per week) since these activations occur during few time steps and for a limited volume only. On the contrary, the costs of the alternative security model due to the additional procurement of upward RR are higher (on average € 600,000 per week) since these additional reserves modify production decisions for a large volume and for many time steps.

[119] However, it should be noted that this activation of cheap hydroelectric plants on the balancing mechanism is made at the expense of incentives sent to BRPs through the ISP in the alternative security model.

Conclusions

In this part of this thesis, the short-term issue of the security of the power system has been studied. To ensure this security, TSOs rely on some capacities which are available in real time to be activated upward or downward to solve imbalances: these capacities are called reserves. Due to their characteristics of public good, reserves are likely to be undersupplied by market players. That is why TSOs have implemented a specific model to ensure their presence in real time in a sufficient level: the so-called security models. The main solution is to procure the needed reserves ahead of real time thanks to a procurement market. However, some differences can be noticed in the extent TSOs rely on the procurement market to provide all needed reserves. In particular, in this thesis, two security models are studied: the "margin approach", which is currently implemented in France (and then called the French security model), and the "reserves approach", implemented in several European countries such as Germany or the Netherlands (called the alternative security model in this thesis). These models differ based on the actions the TSO can undertake to ensure the presence of enough reserves in real time. With the reserves approach, the TSO has only one solution to ensure the presence of enough reserves in real time: the procurement of reserves ahead of real time. In particular, it cannot react if the procured level is not sufficient to deal with expected imbalances. Consequently, it should procure a level of reserves high enough to deal with likely imbalances in real time, even in the worst cases. With the margin approach, the TSO still procures some reserves forward. However, contrary to the previous solution, it can react if it reckons that reserves will not be sufficient in real time to solve imbalances. More precisely, the TSO tries to evaluate ex-ante the reserves which will be provided without procurement by market players. If these reserves added to previously procured reserves are not sufficient to deal with possible imbalances, the TSO increases the level of reserves by activating special bids called activations to ensure system margin. The TSO has then a certain flexibility to ensure the availability of reserves. The main consequence of this possibility for the TSO to activate special bids and to react in case it forecasts a lack of reserves compared to the required level is that the level of procurement can be reduced compared to the reserves approach.

The economic characteristics of both aforementioned security models are studied in this part of this thesis. In particular, it quantifies what would be the costs or benefits for the

French power system, which currently uses a margin approach, to change its security model and implement a reserves approach. To answer this research question, a modelling based on an agent-based approach is developed. This approach enables to model the complex short-term sequence of markets and mechanisms while considering technical constraints of power plants which is needed to accurately assess the margin study in the French security model. Moreover, the modelling is applied to the French power system. Based on computations of the French TSO, an additional 1,800 MW of upward RR and 3,800 MW of downward RR would have to be procured if the alternative model were implemented in the French power system. Both security models are then compared for fifteen different weeks.

The main results show that the French security model, based on a margin approach, always results in lower production costs than the reserves approach. On average, over the fifteen studied weeks, the difference in production costs is around € 545,000 per week.

The lower production costs of the French security model computed with the simulations are mainly explained by the distortions of the merit order imposed to ensure security in both security models. With the French one, the merit order (i.e. the fact of producing with the cheapest plants considering their technical constraints) is distorted when activations to ensure system margin are performed, namely during a limited number of hours (on average 30 hours for the whole week based on the fifteen simulated weeks) and for a limited volume (on average 160 MW). These activations distort the merit order since, most of the time, an expensive production from coal-fired or CCGT plants is imposed on the system whereas it is not necessary to balance the system. In the alternative security model, the distortion of the merit order are more important. Even if, among the 1.8 GW of additional upward procurement, 400 MW can be provided by combustion turbines without modifying the merit order, the remaining 1.4 GW are mainly provided with hydroelectric plants identified as mid-merit generation in the modelling (on average about 1 GW is provided by these plants). Then, it distorts the merit order since more expensive plants have to produce instead. This distortion occurs for a large volume (up to 1 GW) and for many time steps, both during peak (when CCGT and coal-fired plants produce instead of hydroelectric plants) and off-peak hours (when CCGT and coal-fired plants produce instead of nuclear plants because they have to remain online because of technical constraints). The costs due to the distortion of merit order on the day-ahead market in the alternative model (i.e. the production with coal-fired and CCGT plants instead of hydroelectric plants) can be reduced with the activations on the balancing mechanism since hydroelectric plants identified to provide upward RR become available and may enable to avoid activating more expensive technologies (such as combustion turbines). However, these activations are made at the expense on the incentives to help balancing the system sent to BRPs through the ISPs which may be in the wrong direction in the alternative model in case of upward trend (which does not occur in the French security model). The final consequences on these distortions of the merit order are a higher production of coal-fired and CCGT plants in the alternative security model by on average 440 MW compared to the French one. As a result, productions costs are lower in the French security model since hydroelectric plants are more likely to produce as a real mid-order generation compared to the alternative security model.

The previous costs differences are only explained by the solutions implemented by the TSO to ensure having enough reserves to be able to cope with large negative imbalances, i.e. the additional upward RR procurement or the activations to ensure upward system margin. When focusing on the downward margin and the assurance for the TSO to have enough available capacities to deal with large positive imbalances, it appears that both security models are similar and do not result in additional costs. This is explained by the higher flexibility of French nuclear plants compared to the ones installed in other countries. Then, costs associated with the downward reserves are zero in both security models.

From a more general point of view, the lower economic efficiency of the alternative model can be explained by two main reasons. First, the dimensioning of the reserves volumes in the alternative model, carried out well before knowing the effective need, leads to an over-dimensioning of the quantity to be procured and then to higher distortions on the day-ahead market. On the contrary, the dynamic analysis of required margins enables the French security model to refine the real need for reserves (based on the consumption level for instance) and then to limit the quantity to be procured and the associated distortions of the energy market. Secondly, the lower production costs of the French security model are explained by the consideration of the technically available capacity offered by BRPs on the balancing mechanism through voluntary bids (which is mandatory in France for plants connected to the transmission network) within this model.

By relying on these capacities made available by BRPs without any previous procurement, the TSO has more resources to ensure a sufficient level of reserves and can thus procure a lower level of reserves. In the problematic situation where the level of available capacity is not sufficient, the TSO can also react thanks to activations to ensure system margin. On the contrary, in the alternative model, the TSO cannot rely on these available capacities because it is not certain of their level and cannot react if they are not sufficient. A higher volume has then to be procured. The value of the technically available and non-procured capacity is therefore fully captured by the French model, which is not the case in the alternative model.

Part II. Market design of a long-term issue: the economic comparisons of two types of capacity remuneration mechanisms

In this second part of this thesis, the question of adequacy and the ability of power markets to induce efficient investments in generation capacities are studied. Electricity market reforms have deeply changed the way investment decisions in power plants are made. They are now made by several profit-based market players. Even if, in theory, a competitive short-term market induce optimal investment decisions, several market failures can impede this and the traditional energy market may result in under capacity. This justifies the introduction of new mechanisms, called Capacity Remuneration Mechanisms (CRM), to support investments and to solve the adequacy issue. In particular, two mains solutions are considered in Europe: the capacity market (which is implemented in Great Britain and in France) and the strategic reserve mechanism (implemented in Belgium, Sweden, Finland and in Germany). Besides, ensuring the adequacy of power systems is not only about investing in the right amount of capacity: it is also about doing it at the right time. However, several characteristics of investors, such as their imperfect foresight or their herd behaviour, can result in cyclical tendencies in generation investments. Consequently, the dynamic aspects of generation investments also matter when studying the adequacy issue. This issue will be the subject of this second part of the thesis. The economic performances of two CRMs, the capacity market and the strategic reserve mechanism, will be assessed and compared from a dynamic point of view. Such comparisons will bring insight to policy makers regarding the best CRM to implement to solve the likely adequacy issue occurring in current energy-only markets.

This part is structured as follows. The chapter 5 introduces the context of investment decisions in current energy markets and the need to introduce CRMs. In particular, the dynamic aspect of investment decisions and their likely cyclical tendencies are presented. The research question, and how it fits into the current literature, are also described in this chapter. In the chapter 6, the modelling used to study and compare the two types of CRMs (the capacity market and the strategic reserve mechanism) are developed. Finally, the input parameters of the simulations, the results and the economic comparison between both CRMs are presented in chapter 7. This part or the thesis has been partially and initially published in Energy Policy[120].

[120] Nicolas Hary, Vincent Rious, Marcelo Saguan, The electricity generation adequacy problem: Assessing dynamic effects of capacity remuneration mechanisms, Energy Policy, Volume 91, 2016, Pages 113-127.

Chapter 5. Investment issues in current power systems and presentation of the research question

Résumé du chapitre 5 en français :

Dans cette seconde partie de la thèse, la question des investissements en capacité et de la problématique d'adéquation en capacité est étudiée. A la suite des réformes électriques, le processus de prise des décisions d'investissements a été profondément modifié. Autrefois prises par une entreprise en monopole qui maximisait en théorie le surplus social, elles résultent désormais de décisions décentralisées d'entreprises concurrentes cherchant à maximiser leur profit. Même si, en théorie et sous certaines hypothèses, ce changement de paradigme peut conduire aux mêmes décisions d'investissements optimales qu'avec l'ancien monopole, plusieurs défaillances de marché et de régulation dans les systèmes électriques actuels font peser un risque de décisions d'investissements non optimales. C'est la théorie du *missing money* qui peut conduire à des sous investissements, un nombre d'heures de délestages plus important qu'à l'optimum et donc des coûts plus élevés pour la société.

Pour résoudre ce problème d'adéquation de capacité, une principale solution consiste à modifier le *market design* afin d'ajouter un nouveau mécanisme dont le but sera de contrôler la capacité installée. Ce nouveau mécanisme est appelé mécanisme de capacité. En particulier, deux grands choix de mécanismes de capacité apparaissent en Europe : le marché de capacité, mis en place par exemple en France et en Grande-Bretagne, et le mécanisme de réserves stratégiques, mis en place en Belgique ou en Allemagne.

Par ailleurs, la question de l'adéquation ne se pose pas uniquement d'un point de vue statique, à l'équilibre. Il est également important d'étudier la dynamique des investissements. En effet, du fait de plusieurs caractéristiques particulières des acteurs et des marchés, il existe des risques de voir apparaitre des cycles dans le niveau de capacité installée (phases de sous capacité suivies de phases de surcapacité). L'atteinte d'un équilibre de long terme peut même ne pas être assurée. Ainsi, la question de l'adéquation et des solutions utilisées pour résoudre le problème de *missing money* doit se poser également d'un point de vue dynamique.

En particulier, il convient de comparer les performances économiques (en termes d'adéquation mais également en termes de coûts) d'un point de vue dynamique du marché de capacité et du mécanisme de réserves stratégiques afin d'identifier la meilleure solution à implémenter. A l'aune de la littérature actuelle, cette question ne peut être résolue. Elle constitue ainsi l'objet de recherche de cette seconde partie de la thèse.

The previous part of this thesis focused on short-term issues of power system and in particular on its ability to meet the actual load and to respond to short-term variations on the supply or demand side (for instance due to forecast errors on consumption or due to outages on power plants). However, on the short-term timescale, existing capacities are fixed and cannot be modified by the TSO or market participants. The investment decisions are made on a longer timeframe, corresponding to the construction time of power plants (at least several years). Long before real time, it is then necessary to make optimal investment decisions in advance in order to have a sufficient level of installed capacity to meet the expected load in real time: the ability of the system to have enough installed capacity is referred as the capacity adequacy in the literature. Contrary to the security dimension previously studied, it involves a longer time horizon, up to several years before the real time (Rodilla, 2010).

In a first section, the change of paradigm in investment decisions following market reforms will be described. Even if, in theory, a competitive short-term electricity market can induce optimal investment decisions as explained in section 2, several market failures are likely to occur in current power markets and then impede the reach of a long-term optimal state (section 3). That is why several countries have implemented (or are implementing) new mechanisms, called capacity remuneration mechanisms (CRM), to solve the adequacy issue (section 4). Different designs of these CRMs co-exist in Europe or in the USA. Moreover, the question of investments should also be studied from a dynamic point of view since power markets are prone to experience cyclical tendencies in generation investments (section 5). CRMs should then also consider this dynamic aspect of investments when they are designed and their performances assess accordingly. This will lead to the research question of the part of this thesis, namely the economic comparison of different CRMs from a dynamic point of view (section 6).

5.1. A change of paradigm in investment decisions in the wake of market reforms

Power market reforms in recent decades and the introduction of competition within the generation side have deeply changed the way investment decisions in generation assets are made (Dyner and Larsen, 2001; IEA, 2003; Kagiannas et al., 2004). In previous regulated systems, these decisions were theoretically view as made by a monopolistic utility maximizing social welfare. It notably aimed at reducing the total costs of providing electricity to consumers, considering both the investment and variable costs. The electricity tariffs were then determined so that all costs (included fixed costs) were covered, for instance thanks to a cost-plus regulation. As a result, the electricity price was not considered by the monopoly to assess the profitability of its future investments and was only a consequence of previous investment decisions. Moreover, investment risks (for instance due to wrong consumption forecasts) were not borne by the utility but passed through the tariffs to final consumers. It can also be noted that, since only one player was involved in investment decisions, coordination in generation investments was not an issue. For instance, a monopoly did not have to forecast investment decisions of its competitors since it supplied all demand[121].

Following the introduction of competition on the generation level and the end of the former monopoly, investment decisions are now decentralized and made by several profit-based market players. From now on, investments are computed based on a profit maximization program. To compute their likely future profits, market players have to forecast the electricity price at which they will sell their production. Contrary to the previous regulated system, price is essential to assess whether they will cover their costs, in particular their fixed costs, and then whether it is relevant to invest in a new plant. As a result, investors will forecast hardly predictable prices over several years and will invest accordingly in order to earn the highest profit. They also have to forecast the production costs of their plants, and in particular the fuel costs which can be highly volatile. Investors then face a high uncertainty to make investment decisions compared to the previous

[121] The vertical monopoly was also responsible of network investments. Then, it could coordinate investments in generation assets and in network in order to minimize the sum of both costs, for instance by building a power plant where there were frequent bottlenecks on the grid. However, in this part, to simplify, network constraints are not considered.

regulated organization. Besides, these uncertainties and associated risks are mainly borne by investors themselves: if they invest in the wrong amount or in the wrong technology because of incorrect price forecasts, they will have to bear the corresponding costs alone and may risk to be bankrupt. Contrary to the former utility, investors do not have any guarantee that they will cover their costs through the electricity prices. This uncertainty can largely impact investment decisions. Finally, following the introduction of competition, coordination in investment decisions may become more complex since several market players perform their own development planning, with limited information about the investment decisions of their competitors. More difficulties in coordination can also result in long-term inefficiencies.

5.2. In theory, the short-term electricity price can replace efficiently the former coordination of the monopoly and induce optimal investment decisions: the theory of spot pricing

Despite the change of paradigm about investment decisions, microeconomic literature applied to power market has shown that, under certain assumptions introduced thereafter, the introduction of competition and the decentralized actions of several rival and profit-based market players can result in the same optimal decisions, in particular regarding investment decisions, as in the case of a unique utility which maximized social welfare (Caramanis, 1982). In particular, in the short-term market (for instance on the day-ahead market), microeconomic theory suggests that private market players should sell their generation at their short-term marginal costs, which results in the same dispatch decisions as for the former benevolent utility (Rodilla and Batlle, 2012). The short-term electricity price is then defined by the marginal cost of the last unit that clears the market according to the merit-order principle (provided that there is enough capacity). Moreover, short-term price sends optimal signals to market players to invest efficiently in the right types of power plants and for the right amount as the former utility which maximized social welfare did (Rodilla and Batlle, 2012): this is the so-called theory of spot pricing of electricity. At the equilibrium, an efficient mix can be reached where each plant can cover exactly its fixed and variable costs.

In particular, even by submitting bids at their marginal costs, market players cover their fixed costs thanks to the rents they earn during hours when they produce and when electricity prices are higher than their marginal costs. For instance, a baseload plant like a nuclear plant covers its fixed costs whenever the price is defined by a more expensive technology, such as a coal-fired plant or a CCGT plant, during hours with a higher demand: this rent is defined as the inframarginal rent. To cover the fixed costs of peak units (i.e. of the most expensive technology and then the last to be called to produce), there have to be some hours when the available capacity is not sufficient to cover all demand and when electricity price has to soar above the marginal costs of the peak unit: these hours are defined as extra-peak hours and money earned during these hours is referred to as the scarcity rent. During these hours, some consumers have then to decrease their consumption. From an economic point of view, this situation is relevant: during these hours, the cost of supplying an extra MW of demand by building additional capacity is higher than the willingness to pay of consumers. Two situations are often discussed in the literature concerning this reduction of demand during extra-peak hours.

In the first situation, it is considered that the demand has sufficient short-term price elasticity. During extra-peak hours, to reach the supply-demand equilibrium, the electricity price then increases above the variable costs of peak plants so that some consumers reduce their demand voluntarily since the price becomes higher than their willingness to pay. During these few hours, peak plants then earn money to cover their fixed costs. This solution is then a first best solution (Rodilla and Batlle, 2012).

In a second situation, this assumption of sufficient price elasticity is challenged. Indeed, current technologies do not enable consumers to express their willingness to pay in real time and then their consumption cannot be reduced accordingly (Littlechild, 2003). Demand response is then limited and the equilibrium between supply and demand may not be reached. In theory, there is no limit to electricity prices in this case. Several authors then proposed to define an electricity price cap to avoid overcharging consumers during the extra-peak hours and to avoid that they pay an electricity price higher than their willingness to pay (Hobbs et al., 2001; Stoft, 2002). Literature suggests to define this price at the average value of lost load (VOLL). Since it is impossible to measure the willingness to pay for each consumer and to reduce its consumption accordingly, demand is reduced arbitrarily and randomly through rolling blackouts (for instance for a whole district), independently of the willingness to pay of affected consumers. An average willingness to pay, reflected in the VOLL, is then used in this situation to estimate the economic value attributed to unsupplied energy. Moreover, Stoft (2002) showed that defining the price at this value during extra-peak hours when demand should be reduced results in efficient generation investments as the previous utility maximizing social welfare could have done. The theory of the spot pricing still holds even in case of demand inelasticity as soon as the price is defined at the VOLL during hours when available capacity is not sufficient to supply the whole demand. This is the so-called VOLL pricing theory. However, this solution is only a second best solution since consumers whose demand is not entirely satisfied are chosen randomly, independently on their willingness to pay. Consumers whose willingness to pay is very high can be undersupplied at the same level as consumers which can easily reduce their consumption. Welfare is then not maximized, which explains why this solution is only a second best optimum. Moreover, this solution can be difficult to implement in practice given the complexity of assessing the VOLL. Indeed, its value depends on many factors, for instance the type of consumers affected by the arbitrarily reduction of demand, the time when demand is reduced, its duration, etc. Its valuation may also depend on the method used to define it (for instance direct survey, macroeconomic approaches…) (London Economics, 2013; Schröder and Kuckshinrichs, 2015). Different values of VOLL can result in different investment decisions and may impede the reach of efficient investment decisions if wrongly assessed.

To conclude, at equilibrium, regardless of the elasticity of demand, a competitive and deregulated electricity market where market players sell their generation at their marginal costs on the short-term market as advised by microeconomic theory will result in optimal[122] investment decisions. In theory, the electricity price enables to reach an optimal long-term coordination of investments. In particular, fixed costs of plants are exactly recovered and long-term profits are zero. It should also be noted that to cover fixed costs of peak technology, it is necessary and efficient to perform some demand reduction during few hours: this number of hours depends on the fixed costs of the peak technology and on the willingness to pay of consumers. It is then possible to define an optimal number of hours of shortages for a power system and an optimal level of installed

[122] Given the current inelasticity of demand in power markets, the term 'optimal" will refer to the second best solution (i.e. the VOLL pricing theory) in the remaining of this part.

capacity based on these values. Moreover, according to the spot pricing and VOLL theories, if the system is not at equilibrium, the market and the associated price react to reach a new equilibrium. For instance, following a demand increase, without new investment, the number of hours when demand has to be reduced and when prices are defined above the marginal costs of the peak technology increases: then, power plants cover more than their fixed costs and make long-term profits. It attracts new investments which will reduce the profit up to the point it becomes exactly zero at the new equilibrium (Green, 2006). Market is then able to send the correct price signals to reach the socially optimal level of capacity, as a benevolent monopoly would do. According to literature, classic microeconomic theory also applies to the specific case of electricity generation. However, several assumptions are necessary to observe these efficient outcomes, such as a perfect competitive market with perfect information, an efficient allocation of risk or the absence of economies of scale or lumpy investments (Rodilla and Batlle, 2012).

5.3. Several market and regulatory failures impede from reaching efficient investment decisions

However, there is a huge gap between theory and practice in power markets because of the specific characteristics of electricity; reaching the aforementioned optimal investment decisions based on the electricity price only may then be challenged. In particular, the existing literature is highly suspicious whether current market design can induce optimal investment decisions. It has pointed out several market failures impeding it. In particular, there are large concerns about the ability of energy market to send efficient price signals to remunerate sufficiently generation assets at equilibrium. This issue is generally referred to as the missing money problem in the literature, i.e. as Cramton and Stoft (2006) define it, the fact that "when generation capacity is adequate, electricity prices are too low to pay for adequate capacity". All fixed costs are not covered and market players make negative profits[123]. As a result, this situation cannot be at equilibrium. Market players react by decreasing their investments or decommissioning their plants so that there are more hours

[123] However, in case of overcapacity (i.e. not at the equilibrium), the fact that market players make negative profits is normal: this is simply a price signal sent by the market to decrease the total installed capacity so that a new equilibrium is reached.

when electricity prices are defined above the variable costs of the most expensive plants. Consequently, reduction of demand (either voluntarily through demand response or arbitrarily through rolling blackouts) occurs more frequently than in the optimal situation. From an economic point of view, this situation is inefficient since it is necessary to reduce the demand of some consumers whereas their willingness to pay is higher than the generation costs of providing the corresponding energy.

Several authors have studied the existence of the missing money and more generally the reasons of likely under investments in current liberalized energy markets. Four main reasons are mentioned in the literature and developed below:

- The inability of prices to increase up to the VOLL during extra-peak hours
- The imperfect information, the risk aversion and the incompleteness of markets
- The no-excludability nature of adequacy
- The lumpiness of investments in generation assets

5.3.1. The inability of prices to increase up to the VOLL during extra-peak hours

During extra-peak hours, electricity price should theoretically rise up to the VOLL to cover fixed costs of peak plants. However, in practice, a price cap is often defined on power markets at a level well below the VOLL. For instance, in France, the price cap is equal to 3,000€/MWh on the day-ahead market and € 10,000/MWh on the intraday and balancing markets whereas the French TSO estimates the VOLL at € 26,000/MWh (RTE, 2011). This price cap is often implemented to avoid the exercise of market power. In particular, it can be difficult for regulators to distinguish during extra-peak hours between high prices due to the market power abuse, and which is detrimental for consumers and social welfare, and high prices necessary from an economic point of view to cover fixed costs (Cramton and Ockenfels, 2012). Moreover, during hours when balance between supply and demand may be difficult and would require rolling blackouts and a price defined at the VOLL, the TSO often performs preliminary actions out of market to avoid resorting to these shortages (Joskow, 2006). For instance, it may reduce temporarily the system voltage to decrease the consumption. In France, a 5%-voltage reduction can reduce the consumption by 4,000 MW[124]. However, these actions are not valued on the market: they may impede electricity prices from reaching high level and then reduce scarcity rents.

5.3.2. The imperfect information, the risk aversion and the incompleteness of markets

The spot pricing theory (or VOLL pricing theory) assumes a perfect information of investors. In reality, the future outcomes are unknown when making investment decisions (de Vries, 2007; Rodilla and Batlle, 2012). In particular, to assess the future profitability of its plant, a market player has to forecast electricity prices and the quantity it will produce and sell. These forecasts then require to anticipate the electricity demand and supply, notably the likely investment decisions made by competitors. Moreover, they depend on many hardly predictable variables, such as weather conditions, the macroeconomic situation, the evolution of fuel and CO_2 costs… The massive development of renewable and intermittent technologies (wind and photovoltaic mainly) increases the price volatility and then the difficulties to forecast future revenues (Nicolosi and Fürsch, 2009). These forecasts are all the more difficult as they should take place several years ahead (due to the long lead time of power plants) and should consider a long horizon (since the lifespan of plants is generally several decades). Investors also face a regulatory risk. Indeed, market design of power systems frequently evolves. These changes may impact future revenues of new investments and create an additional uncertainty (for instance, the environment policy may impact the profitability of polluting plants). Similarly, the development of intermittent technologies promoted by current green policy thanks to subsidies has highly modified revenues on the energy market for thermal plants. When their investment decisions were made several years ago, the impact of wind and photovoltaic production was hardly predictable. Moreover, these uncertainties mainly affect investments in peak technologies which cover their fixed costs during very few hours only.

Faced with these high uncertainties, investors tend to be risk averse (Meunier, 2013), contrary to the assumption made in the theory of spot pricing. Since their profit are highly

[124] See https://www.actu-environnement.com/ae/news/consommation-electrique-prevision-hiver-2016-froid-fourniture-electricite-rte-27831.php4

uncertain and volatile depending on future outcomes which they cannot forecast perfectly, they tend to be conservative when making investment decisions and protect themselves against the most detrimental scenarios by not investing. In theory, it should be possible for investors to hedge and trade these risks using forward and financial markets and then avoid underinvestment (de Maere d'Aertrycke et al., 2017). For instance, investors may sign long-term contracts with consumers. However, several authors highlighted the incompleteness of electricity markets and the difficulty to hedge efficiently against investment risks (Finon, 2011; Neuhoff and De Vries, 2004; Willems and Morbee, 2010). Consequently, market players tend to reduce their investment decisions. For instance, instead of considering the average profit of their plants over several different future scenarios, investors may rely on a corrected value to consider the volatility of these results, such as the conditional value at risk (de Maere d'Aertrycke et al., 2017). Then, compared to risk neutral investors, they tend to postpone their investment decisions until they forecast high enough revenues. In other words, more hours when demand needs to be reduced are necessary to trigger investments compared to a situation where investors are risk neutral. This situation is then suboptimal. Risk aversion is particularly true for peak plants, especially in current markets with massive development of intermitted technologies (de Sisternes and Parsons, 2016; Tietjen et al., 2016). Indeed, their revenues during extra-peak hours are highly volatile: depending on weather conditions for instance, they may earn nothing during several years and make important profits for few days only during a cold wave. Investors are then likely to reduce their investments in this technology compared to risk-neutral players.

5.3.3. The no-excludability nature of adequacy

The characteristic of adequacy as a public good is highly debated in the literature. Even if the characteristic of non-rivalry is challenged (Klinge Jacobsen and Jensen, 2009), several authors have highlighted its non-excludability given the current technologies (de Vries, 2004; Finon and Pignon, 2008; Stoft, 2002). Indeed, if a market player decides to invest in a new power plant and then improves adequacy of the power system, it will benefit to all consumers connected to the network, whether their electricity is supplied by the market player which invests in the new plant or not. With current technologies, it is impossible to reduce demand of consumers individually depending on their willingness to pay or if they have signed a contract with the market player which has built the new plant. It is then impossible to exclude individually consumers from benefiting from adequacy. Once adequacy is ensured, all consumers connected to the network can enjoy it.

As a result, non-excludability leads to the classic free-rider issue: the market underprovides adequacy compared to the optimal solution. Indeed, a market player is not incentivized to invest in a plant which will increase adequacy since it will not be possible to monetize it entirely. In particular, since consumers cannot be disconnected individually, this market player cannot contract with consumers whose willingness to pay is high and which do not want to be disconnected. Since it cannot value all surplus of private agents, it will not invest and liberalized markets tend to under capacity compared to the optimal outcome.

Nevertheless, it should be noted that this key characteristic of non-excludability is not an intrinsic feature of power system but mainly depends on technology improvement (de Vries, 2004). In particular, thanks to the implementation of real-time meters, it will be possible to disconnect individually consumers during extra-peak hours. Then, the free riding issue will be reduced.

5.3.4. The lumpiness of investments in generation assets

A last major reason mentioned in literature regarding the likely underinvestment in generation assets is their lumpy characteristics (Rodilla and Batlle, 2012). Indeed, it is only possible to build power plants for discrete size (for instance, 400 MW). Even in case of perfect information or if market players are risk neutral, it may result in underinvestment. For instance, if the power system lacks 200 MW to reach the optimal level of installed capacity, it may be impossible for investors to build exactly a 200 MW-power plant. They may have the choice between building a 400-MW plant and not investing. In the first case, the power system will be in overcapacity and there will be no scarcity rents: market players will then make negative profits. In the second situation, there will be more rolling blackouts than optimal and market players will make positive profits. Then, from a private perspective, they will choose the second solution and tend to underinvest.

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To conclude, because of several market failures, traditional energy markets are expected not to induce optimal investments contrary to what the theory expects. In particular, there are several reasons supporting a risk of underinvestment which will result in more than optimal rolling blackouts. Since blackouts are very costly for the society (in particular because they are performed randomly and then may affect consumers with a high willingness to pay) compared to the costs of overcapacity, there is a strong asymmetric loss of welfare if the optimal situation is not reached (de Vries, 2004): the social costs of under capacity are larger than the social costs of overcapacity. That is why literature and policy makers propose several solutions and improvements of market design to avoid likely and detrimental situation of underinvestment.

5.4. Modifications of market designs to solve the adequacy issue and development of capacity remuneration mechanisms

Two main principles can be distinguished regarding the solution to induce optimal investment decisions.

Firstly, some authors support the idea that energy-only market (i.e. traditional power markets where only produced energy is remunerated) can be improved and the aforementioned market failures can be mitigated in order to ensure adequacy (Hirst and Hadley, 1999; Hogan, 2005; Shuttleworth, 1997). In particular, they highlight the need to better reflect scarcity pricing in the price of energy, for instance by removing any price cap, and the need to increase demand response.

On the contrary, others support the idea of introducing a complementary mechanism, added to the energy market, to ensure generation adequacy: these mechanisms are called capacity remuneration mechanisms (CRM) and they aim at reaching an optimal level of installed capacity and reducing shortages to the optimal level by creating an additional remuneration for capacities. Different types of CRMs can be distinguished in the literature and are implemented in the USA or in Europe. A traditional taxonomy is presented in figure 55 and discussed below (ACER, 2013; Batlle and Rodilla, 2010; CREG, 2012; de Vries, 2004; European Commission, 2016; Finon and Pignon, 2008).

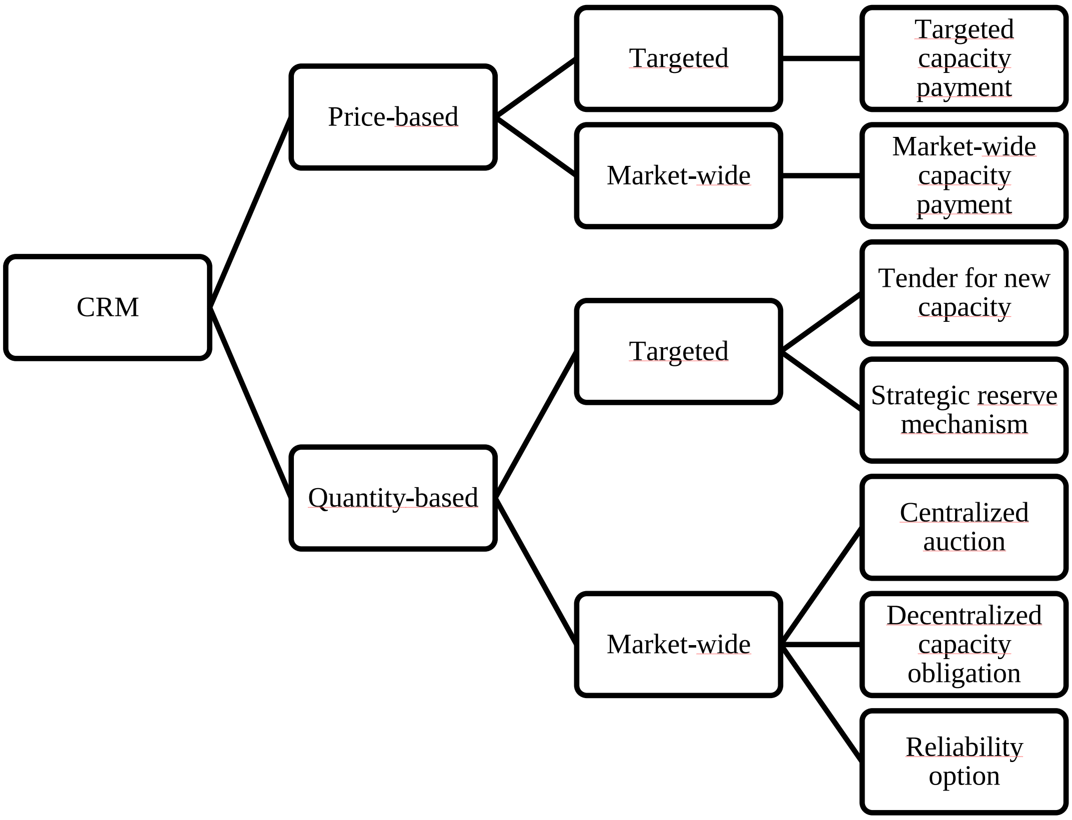

Figure 55: Taxonomy of main CRMs

A first distinction lies in the use of a price instrument or a quantity instrument to reach the optimum. A second distinction lies in the definition of the capacity which is concerned by the CRM: either it involves all installed capacity without any distinction or it can target only specific capacity (for instance peaking units or plants with low emission factors). Based on these two distinctions, several types of CRMs can be distinguished.

Regarding the price-based policies, the main instrument is the capacity payment. It aims at paying each installed MW at an administratively fixed price in order to cover the missing money. The installed capacity is then independently determined by the actions of market participants. In addition to the remuneration coming from the energy market, the capacity payment can be limited to some specific plants (targeted capacity payment) or opened to all installed plants (market-wide capacity payment). This scheme is currently implemented in Spain (European Commission, 2016).

Regarding the quantity-based and targeted instruments, two mains solutions can be noticed: the tender for new capacity and the strategic reserve mechanism. With the first solution, a tender is organized by a third party (for instance the TSO) to procure some missing capacity. The winner of the tender then receives financing for the construction of the power plant. Usually, this plant can produce normally on the energy market as any other plants. It was notably implemented in Ireland for a 500 MW CCGT (European Commission, 2016). The second solution in this category is the strategic reserve mechanism. In this case, some capacity is contracted by the TSO and is withdrawn from the energy market: these plants cannot sell energy anymore except in scarcity situation as a last resort. Strategic reserves are contracted using a tender and they are often old and expensive plants which would have been shutdown otherwise. Moreover, the amount to be contracted is usually defined on a yearly basis by the TSO based on its own forecast about the future adequacy conditions. Plants which are not contracted by the TSO do not receive any capacity revenues: their main revenues are still coming from the energy market which remains the main driver of investment and shutdown decisions. When designing this mechanism, it is important to define properly the conditions under which the strategic reserves can be activated by the TSO in order to avoid any distortions of the energy market. Indeed, when activating, these plants define an implicit price cap on the energy market (Finon et al., 2008). In particular, the TSO should avoid activating these reserves too often which would dampen energy prices and increase the missing money, the shutdowns of plants and then the need of larger strategic reserves (this phenomenon is called the slippery slope effect) (European Commission, 2016). This solution has been implemented in Finland, Sweden and recently in Belgium. It will also be enforced in Germany (European Commission, 2016).

Finally, regarding the quantity-based and market-wide CRMs, three mains instruments are described: a centralized auction (also called central buyer mechanism), a decentralized capacity obligation and a reliability option mechanism. The first two solutions are often referred to as capacity markets. With the centralized auction, a third party (generally the TSO) defines the amount of required installed capacity. It then ensures availability of this level through an auction where all potential capacity providers (existing or future plants, storage facilities, demand response and sometimes interconnectors) compete. Submitted bids should in theory reflect the difference between costs of capacity providers and their expected revenues on the energy market. Moreover, this auction takes place several years ahead in order to enable new plants to compete and to have time to be built if accepted. Successful bids then earn the capacity price determined by the intersection of the demand and supply curves. In theory, the capacity price should be linked with the missing money the plants experience in the energy market. As a counterparty of this remuneration, capacity which clears the capacity auction commits to be available during peak periods and produce if needed (otherwise, they are usually subject to penalties). Several US ISOs have implemented this type of mechanism for several years (for instance PJM, New-York ISO or ISO-NE) (CREG, 2012). Great Britain has introduced it in 2014 (European Commission, 2016) and Ireland in 2017 (EirGrid, 2017).

The decentralized obligation scheme is quite similar to the previous mechanism except the TSO transfers the need to procure enough capacity to electricity suppliers or retailers. These market parties have then an obligation to procure by themselves enough capacity to meet their consumers' demand. To meet this obligation, they can either use the capacities they own (generation or demand response) and/or purchase capacity certifications from other market players, in particular through organized capacity markets. Contrary to the centralized auction, the demand curve for capacity is defined by decentralized market players. However, even if a central entity does not necessarily define the volume that each supplier has to procure, it generally sets the rules to define it. The capacity price is believed to be established by market forces. Moreover, in case suppliers do not have enough capacity certificates (for instance if they underestimate the consumption of their costumers), an ex-post imbalance settlement process is organized to incentivize market players to be balanced and then reach the optimal level of installed capacity. This solution has been implemented in France in 2016 (European Commission, 2016).

Finally, the last example of quantity-based and market-wide solution is the reliability option. With this scheme, the TSO determines an amount of capacity to be procured by capacity providers. Contrary to previous mechanisms, the exchanged capacity products are defined as call options whose strike price is defined by the TSO. In case the energy price is higher than this strike price, the TSO calls the option and capacity providers which have sold an option have to pay the difference between the actual electricity price and the strike price to the TSO (which is ultimately passed on consumers). This strike price then reduces revenues of power plants during scarcity hours: this reduction is reflected in bids submitted by plants on the capacity auction organized by the TSO. The main advantage of this mechanism is to send strong incentives to capacity providers to be available during scarcity periods. Indeed, during these hours, a plant that sold options but which is not producing undergoes a net loss equal to the difference between the strike and electricity prices whereas, if it produces, it generally earns a positive profit (even if it is reduced compared to the case without the call of the option). This scheme is under implementation in Italy (European Commission, 2016).

To select the best CRM to implement, literature compares their performances according to several criteria. Among them, the adequacy-effectiveness and the cost-effectiveness criteria are the main ones. The former refers to the ability of the CRM to solve the adequacy issue and to reach an optimal level of shortages while the latter studies the costs of this CRM and in particular whether there is another mechanism which is less costly but as the same adequacy effectiveness. Other criteria such as the facility of implementation or the robustness to the exercise of strategic behaviour can also be assessed and compared. Among comparisons discussed in the literature, the capacity-based instrument seems to be more effective than a price-based one. Even if both solutions lead to the same results in case of perfect information (Weitzman, 1974), the capacity-based instrument appears to be better when uncertainty and asymmetric information are considered. Indeed, in this case, the slopes of the demand and supply curves should be compared to find the best policy. For the capacity issue, the demand curve is often assumed to be very steep as the social cost of outages increases sharply with the level of shortages (RTE, 2011) whereas the supply curve, usually defined by the cost of peak technologies, is often flat: in this situation, a quantity-based instrument appears to be more relevant[125] (Finon and Pignon, 2008). De Vries (2004) also compared these CRMs. In particular, he found that the strategic reserve mechanism is less effective in securing generation and in stabilizing investments compared to a capacity market but is easier to implement. However, he did not compared them based on their cost effectiveness.

[125] If a price-based policy is chosen, the difficulty to define this price can have significant consequences. In particular, an underestimation could lead to large and detrimental shortages.

5.5. The boom and bust cycles in generation investments

Ensuring the adequacy of power systems is not only about investing in the right amount of capacity: it is also about doing it at the right time (Roques, 2008). Indeed, the dynamic aspects of generation investments also matter regarding the adequacy issue and the reach of a long-term equilibrium is not ensured. As Stoft (2002) pointed out: "*Economics focuses on equilibria but has little to say about the dynamics of a market. Once economics shows that a system has a negative feedback loop so that there is a point of balance, it considers its job done. Engineers move beyond this stage of analysis to consider whether a system will sustain oscillations and, if not, whether it is over- or under-damped. Economics understands that investment dynamics can produce "cycles" but has faith that rationality will generally prevent this*". In particular, the previous theory of spot pricing shows that in case of under capacity (respectively overcapacity), the electricity price rises (resp. decrease) to attract new investments (resp. to incentivize to close some plants) so that a new equilibrium, where the installed capacity level is equal to the optimal level, is reached. Then, the price signal enables a negative feedback loop which, in theory, could result in a long-term equilibrium. However, several characteristics of electricity markets and of investors make this long-term equilibrium difficult to reach. In particular, the risk of cyclical tendencies in generation investments, known as boom and bust cycles, has been highlighted in the literature (Arango and Larsen, 2011; Ford, 2002, 2001, 1999; Green, 2006). These tendencies are materialized by phases of under investment, resulting in under capacity, followed by phases of overinvestment and then overcapacity. Cyclical tendencies are highly detrimental for social welfare. As mentioned previously, the high level of shortages happening during the under capacity phases results in massive welfare losses. Conversely, during the overcapacity phases, shortages are avoided. However, more plants than needed are available to produce. This leads to suboptimal generation costs: it would have been more efficient to build less power plants. Moreover, this overcapacity results in low energy prices and then in likely massive losses for investors since they are not able to cover their fixed costs. Consequently, investors may be more reluctant to invest in the future: the overinvestment phases can then worsen the underinvestment phases. Power systems and private investor's behaviour present many characteristics which can take the system away from equilibrium and explain why investments are prone to cycles. They can be sorted into two categories, regarding the period of overinvestment or underinvestment.

5.5.1. Reasons for the underinvestment phases

Main reasons of underinvestment in liberalized power markets have been previously mentioned. In particular, high uncertainties about future profits combined with the risk aversion of investors and the lack of proper financial instruments to hedge risks tend to delay investment decisions. Besides, the uncertainties faced by investors are magnified by the long lead time for construction and administrative permissions of plants. Investment decisions have then to be made several years in advance. The risk aversion of investors is also accentuated by the fact that investments in generation assets are capital intensive and are irreversible. Thus, investors tend to delay their investments to be sure their plants will be profitable. They tend not to invest immediately when they expect a profit but instead wait for clearer signals of profitability and for additional information. In particular, Dixit and Pindyck (1994) showed that irreversible investments in presence of huge uncertainties should be made using a real option approach instead of the classic NPV approach. Indeed, the investment decision is not about investing now or never but about whether it is better to invest now, even if there are large uncertainties, or to wait some months in order to decrease uncertainties (for instance, uncertainties regarding regulatory risks). Then, benefit of more precise information by delaying the project should be compared with the costs of waiting (for instance, if a competitor invests first) using real options. As a result, even if the NPV appears to be positive, faced with high uncertainties, it may be more relevant for a company to wait for clearer price signals than to invest immediately (Blyth et al., 2007; Green, 2006). It is likely that new power plants come in operation too late, after major shortages appeared as it has been the case in California in 2000/2001 (de Vries, 2004).

5.5.2. Reasons for the overinvestment phases

Conversely, once investments seem to be profitable enough and uncertainties are (partially) cleared, players are prone to overinvestment, *i.e.* to invest more than what would be optimal. It can be explain by a herd behaviour, as Green (2006) mentions: "*In the absence of a coordination device, however, they are in danger of over-reacting – too many investors read the high prices as a signal that their own investment will be* *profitable, and somehow fail to take the likely actions of others into account [which is the so called herd behaviour]".* Even if investors are aware of investments made in the previous years by rival companies (through TSO reports, construction permits…), Ford (2001) says that some scepticism about the completion of announced power plants can discount plants under construction (for example due to environmental activism or administrative issues). Above all, players have limited information about the investment decisions which are made at the same moment (for instance, the same year) by competitors. Moreover, regarding existing plants, even if market players are aware of the risk of overcapacity and the associated low energy prices, they may not want to close their power plants immediately. Similarly to investment decisions, market players may wait for clearer information before closing their plants definitely (Green, 2006). Even if all players agree that some plants should be closed, since the player that actually does so will incur a massive loss (due to the importance of sunk costs), it would prefer that others make this decision. However, eventually, a long overcapacity phase will sharply reduce power prices which will result in massive plants closures and possibly in bankruptcy for investors. This might increase their risk aversion, consequently emphasizing delays in investment decisions and exacerbating cycles.

5.5.3. Support for the existence of investment cycles

Previous explanations of the cyclical behaviour are mainly theoretical. However, several evidence support the idea of likely important cyclical tendencies in generation assets for power markets. First, analogies with other markets, which share particular characteristics with power market (for instance capitalistic investments, long lead time for construction, uncertain demand…) and which experienced cyclical behaviours (for instance the oil tankers industries, the aluminium industries or the real estate market, see Arango and Larsen (2011) for more references and details), support the risk of observing cyclical investments in power markets. Moreover, these markets where cyclical behaviours were noticed are notably known to provide an easier demand and supply balancing than power markets thanks to stock or demand elasticity. Therefore, such a phenomenon should be highlighted in electricity market where balancing is more complex (Arango and Larsen, 2011; Ford, 1999).

Added to these analogies, cyclical tendencies in power markets are supported by simulations which model the imperfect behaviour of investors, notably their likely herd behaviour, their risk aversion or their bounded rationality. In particular, simulations using System Dynamics exhibit the possibility of experiencing cyclical investment (see Arango and Larsen (2011) and references mentioned below). Laboratory experiments also support a cycle hypothesis. In particular, experiments made by Arango (2006) show that "*subjects have a tendency to initiate new projects when they perceive high price, while they tend to ignore capacity under construction and the construction delay*".

Finally, the cyclical tendencies in generation investments are partially supported by empirical data. Such empirical evidence is however limited. Indeed, the recent liberalization provides few data about private investor behaviour, especially as most markets tend to begin with overcapacity. Nevertheless, using data from the oldest liberalized markets (Chile and England), Arango and Larsen (2011) found empirical support of cyclical behaviour based on an autocorrelation analysis.

To dampen detrimental cycles, both during under and over capacity phases, and to reach a long-term equilibrium, several solutions may be possible. First, a classic solution in theory would be to sign long-term contracts between producers and consumers to provide financial stability and reduce investment risks. However, retailers are often reluctant to engage in long-term contracts since they may lose their clients to new retailers at times when their long-term contracts exceed the short-term price (de Vries, 2004; Green, 2006). Moreover, long-term contracts are often too short to dampen the investment cycles which encompass several years. Another solution to reduce the investment cycles lies in mothballing, i.e. the fact of temporarily withdrawing a plant for several months with the possibility of returning on the energy market quickly if market conditions improve. Using an experimental study, Arango et al. (2013) show that mothballing can reduce cycles prone to appear in energy markets. However, mothballing has often been seen as market manipulation by regulators, in particular to increase prices (Roques et al., 2005). Finally, a last solution to dampen investment cycles is the previously introduced CRMs. Several papers, based on a System Dynamics approach (explained thereafter), show how CRMs can reduce investment cycles.

5.6. The importance of the dynamic aspects to compare the performances of CRMs

The previous section highlighted the importance of dynamics when assessing investment decisions. As a result, to consider properly their performances, previously mentioned CRMs should be studied from a dynamic point of view to assess to what extent they can reduce the detrimental investment cycles. Even if CRMs may present similar characteristics regarding the incentives sent to reach the optimal capacity from a static point of view, their performances may differ when considering the dynamic of investments. Literature has then tried to compare these CRMs to select the most efficient one from a dynamic perspective. Most works are all based on a System Dynamics (SD) approach, which presents interesting characteristics to study dynamic aspects as it will be explained in the chapter 6. For instance, Assili et al. (2008) and Park et al. (2007) study how an improved variable capacity payment mechanism can reduce investments cycles. de Vries and Heijnen (2008) compare dynamically capacity payments, operating reserves pricing and capacity markets under uncertainty of the future growth of load. They show that all these mechanisms perform better than a competitive energy-only market, capacity obligations having the strongest stabilizing effect, both with respect to investment and prices. Hobbs et al. (2007) assess the capability of the capacity market in the PJM system to reduce investments cycles. They show that a downward sloping demand curve on the capacity market reduces investment risks and therefore fluctuations in installed capacity and consumers prices, compared to a vertical curve. (Hasani and Hosseini, 2011) compare the capacity payment mechanism and the capacity market through nine technical and economic indicators (in particular regarding shortages, electricity prices and revenues of peak technology). (Hasani and Hosseini, 2013) develop a SD model to compare different designs of capacity payment in the Iranian power market, in particular assessing the reserve margin and the generation expansion costs. They find that a capacity payment mechanism with different payments for each region according to the regions' reliability indices shows lower capacity expansion costs and enables to avoid shortages. (Petitet et al., 2017) compare dynamically three market designs: the energy-only market with a price-cap, the energy-only market with scarcity pricing and a capacity market. The results show that when market players are risk-neutral, the energy-only market with scarcity pricing and the capacity market provide similar performances in terms of social welfare.

However, with risk aversion, the capacity market appears to be preferable. Finally, (Cepeda and Finon, 2011) study from a dynamic point of view the practical problems related to long-term security of supply in regional electricity markets when different CRMs are implemented and when transmission capacity is constrained. They find that the lack of harmonization in CRMs between local markets may lead to undesirable side effects.

The current literature on the dynamic comparison of CRMs can be improved on two points. First, the strategic reserve mechanism, one of the main CRMs implemented and discussed in Europe (in Belgium, Finland, Sweden, Germany…), is rarely studied from a dynamic point of view. Indeed, previously mentioned studies often focus on the capacity market or the capacity payment. Thus, policymakers cannot compare this mechanism with other CRMs to select the best one to implement. Moreover, in the studies mentioned above, comparisons are often based on an adequacy criterion (i.e. to what extent the CRM can reduce shortages and reach the optimal level of shortages). However, the cost effectiveness of the mechanism, i.e. the costs to build and operate power plants to reduce shortages, is often disregarded. Yet, cost effectiveness is one of the main criteria to consider from an economic point of view, in particular when maximizing the social welfare: CRMs have to reduce shortages but not at any cost for society. Policymakers should decide which CRM to implement regarding not only the adequacy-effectiveness criterion (i.e. the reduction of shortages to their optimal level) but also the cost-effectiveness one (i.e. the investment and generation costs). Based on literature, the question of cost effectiveness cannot be answered for a capacity market and a strategic reserve mechanism from a dynamic point of view.

This part of the thesis aims at answering these two missing points, namely to assess the dynamic effects of the capacity market and the strategic reserve mechanism, two of the main CRMs considered in Europe, and to compare them with regard to the adequacy-effectiveness and cost-effectiveness criteria. This question is central in Europe for policy makers when they assess which CRM should be implemented to help to reach the long-term equilibrium. To answer this research question, a modelling of both CRMs is developed. Resorting to modelling is necessary to consider the dynamics of investment decisions and to take into account the complex and realistic behaviour of market players (for instance, their herd behaviour). Moreover, modelling enables to compute more precisely the costs induced by each CRM and then to compare them. This modelling uses a System Dynamics approach, as explained at the beginning of the chapter 6. This chapter also develops the main assumptions. The chapter 7 then introduces the input parameters used for the simulations as well as the results and economic comparison between both CRMs.

Chapter 6. Presentation of the modelling

<u>Résumé du chapitre 6 en français</u> :

Afin de répondre à la question de recherche de cette deuxième partie de la thèse, une modélisation est développée afin d'étudier la dynamique des investissements et des fermetures de centrales. Afin de pouvoir considérer cette dynamique et d'étudier si un équilibre de long terme peut être atteint, une modélisation basée sur une approche *System Dynamics* est utilisée. Cette approche permet de considérer les caractéristiques des marchés et des acteurs pouvant conduire à des cycles et ne présume pas de l'existence d'un équilibre.

Cette modélisation se base sur les travaux de Hobbs. Elle représente au pas annuel les prises de décisions des acteurs concernant leurs centrales (investissements ou fermetures) en fonction de leurs anticipations des revenus futurs. Plusieurs améliorations sont apportées afin de pouvoir répondre précisément à la question de recherche : des fermetures endogènes de centrales sont considérées, un mécanisme de réserves stratégiques est modélisé, les offres sur le marché de capacité sont faites à partir des coûts évitables… Le fonctionnement et la modélisation du marché *energy-only* (i.e. sans mécanisme de capacité), du marché de capacité et du mécanisme de réserves stratégiques sont présentés dans ce chapitre.

This chapter presents the modelling developed and used to answer the research question. The choice of the modelling approach is studied in a first section. Then, a general overview of the modelling is made. Finally, in a last section, the modelling of each market (the energy-only market and both CRMs) is described more precisely and the different assumptions are presented.

6.1. A modelling based on a System Dynamics approach to study the dynamic of investment decisions

The first step requires determining which approach to take: optimization, equilibrium or simulation. Due to the importance of the investment cycles, the performances of CRMs have to be assessed dynamically. To this end, simulation models are needed. Indeed, to gain an understanding of the dynamics of the industry, Gary and Larsen (2000) showed that inclusions of information feedback loops, instead of equilibrium assumptions, are fundamental. Therefore, equilibrium approaches cannot be used anymore to understand and model the cyclical tendencies which do not correspond to an equilibrium and static state. Of course, the same can be said about the optimization approach. Among the different simulations models, Systems Dynamics (SD) modelling, a methodology developed by Forrester (1961), is the main approach used in the current literature to model these feedback loops and to study the dynamic aspects of investments. SD enables to study inter-relationships between the different components, to consider imperfect investor foresight and the delay between the date when investment decisions are made and the date when the plant begins to produce, to understand feedback mechanisms and then to assess the dynamic responses. Thus, using this methodology, cycle behaviours can be analysed, as well as the influence of CRMs on them. For instance, de Vries (2004), Hani et al. (2006), Jalal and Bodger (2010), Kadoya et al. (2005) or Olsina et al. (2006) have applied SD to study the investment dynamics in electricity markets and to highlight the cyclical behaviour. Papers mentioned in the section 5.6 also resort to SD to compare dynamically different CRMs. A SD approach is then applied in this chapter to assess dynamically performances of a capacity market and a strategic reserve mechanism.

Compared to the existing literature, two main features are added in this modelling. First, the strategic reserve mechanism is considered while literature generally disregards it. Moreover, since strategic reserves are mostly old and expensive plants which would have been shutdown otherwise (because they do not earn enough money from the energy market), it is necessary to model the shutdown decisions of plants. In most existing papers studying CRMs from a dynamic point of view, shutdowns of power plants are not considered (for instance, Ford (1999), Hobbs et al. (2007) or Jalal and Bodger (2010)) or are considered as exogenous, i.e. at the end of their lifetime and independently from their revenues from the energy market (for instance de Vries and Heijnen (2008), Hasani and Hosseini (2013) or Olsina et al. (2006)). With an exogenous shutdown decisions of power plants, the costs of using them as strategic reserves can be difficult to compute. Consequently, in the modelling, the second improvement is the consideration of endogenous shutdown decisions based on the comparison of the operations and maintenance (O&M) costs of the power plant, which increase along its lifetime, and its revenues on the energy market. The consideration of these endogenous shutdown decisions enables to have a better comparison of the cost effectiveness of both CRMs.

6.2. General overview of the modelling

To study investment (and shutdown) decisions in liberalized power systems and how CRMs can modify these decisions, a SD modelling is used. It is based on the research developed by Hobbs (2005) and Hobbs et al. (2007) since this original modelling is well exposed and explained in the associated papers, and then easily tractable[126]. The original modelling only considers the capacity market for the PJM region[127] and assesses its performances for different demand curves submitted by the RTO. Results are compared based on reserve margins, generator profitability, and consumer costs. The logic of the original modelling is kept in this chapter. It is presented in figure 56 on a simplified causal-loop diagram. In this diagram, typical for SD modelling, a causal relationship between two system variables is depicted through an arrow. The (+) symbol describes a

[126] To the knowledge of the author, the results of this study should not be dependent on the original modelling choice, as long as the modelling uses a SD approach.
[127] PJM Interconnection is a Regional Transmission Organization (RTO) operating the electricity system including the wholesale market in the North-East of USA.

positively related effect (an increase in the first variable will cause an increase in the second one). The (-) symbol specifies the contrary. Each year, four main steps are run:

- Step 1: market players[128] make anticipations about future market revenues from the energy market, in particular based on past revenues;
- Step 2: These revenues are used by market players to assess the expected future profitability of their plants and then make investment decisions (whether to invest or not, and if so, how much);
- Step 3: These decisions will in turn impact the installed capacity some years later (depending on the lead time of the plants);
- Step 4: The comparison on the actual load and the installed capacity will impact the actual profits made on the energy market.

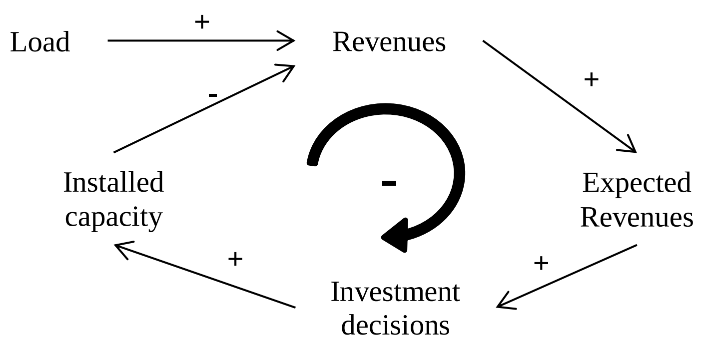

Figure 56: Simplified diagram of the model

The process starts back from the first step, with agents taking into account the observed market outcomes for their future forecasts. An overall negative feedback loop can then be noticed, which could lead to an equilibrium in theory. If a large under capacity phase happens, revenues from the energy market will tend to increase (as there will be more shortages). Consequently, market players will build new power plants, since they expect them to be profitable based on these high revenues. As a result, these new plants will tend to reduce the under capacity phase. However, as explained in the chapter 5 of this part, several failures can impede this equilibrium from being reached.

The main assumptions made by Hobbs et al. (2007) are kept here: an annual time step is used (i.e. market players make investment and shutdown decisions every year), perfect

[128] All market players are assumed to behave the same way. Then the modelling is run as if there is only one aggregated market player.

competition is considered (there is no strategic behaviour), only peak technology is modelled since missing money issue mainly impacts this technology, its lead time is assumed to be four years[129], revenues from the energy market are assessed thanks to a simplified and exogenous function (and not by modelling a short-term energy market) as described thereafter, expected profits are computed thanks to previous and current profits. Moreover, load is summarized by the annual peak load and is expected to increase at an average constant growth rate. However, uncertainties, due to economic growth rate deviation or weather conditions, are added to this average load growth rate and modelled thanks to two independently random variables which are normally distributed (with a zero mean).

In the original modelling of Hobbs, only the capacity market is modelled. Besides, Hobbs et al. (2007) assumed that plants bid at a constant and exogenous price on the capacity market, independently from their real costs and revenues. In this thesis, the modelling is improved to consider a more complex and economically rational bidding behaviour based on avoidable costs. Two other market designs are added: the strategic reserve mechanism and the energy-only market, which is used as a reference case to assess the cyclical tendencies. Moreover, to study a more accurate functioning of the strategic reserve mechanisms, power plant closures are now endogenous (investors decide whether to close their plants regarding their expected profitability). Increasing yearly O&M costs are modelled to reflect aging of plants. Since it is more and more costly to operate plants, investors will prefer ultimately closing them and building new ones. Evolution of these costs with the age of the plant is described in the next chapter about input parameters.

The three studied market designs are introduced thereafter. The aim of this study is to compare both CRMs, i.e. the capacity market and the strategic reserve mechanism (the energy-only market is introduced as a reference design). To facilitate the understanding

[129] The same value as Hobbs et al. (2007) is considered in the modelling. It includes the construction time which is around 2–3 years based on several sources (EIA, 2017; Petitet, 2016) and the time for obtaining all the administrative authorizations and regulatory approvals. In reality the necessary time to complete all administrative and regulatory procedures may depend on specific environmental constraints or land restrictions associated with the location of the plant. A sensitivity analysis regarding the lead time will be performed in section Part II.7.5. In reality the necessary time to complete all administrative and regulatory procedures may depend on specific environmental constraints or land restrictions associated with the location of the plant. A sensitivity analysis regarding the lead time will be performed in section Part II.7.5.

of these CRMs, the energy-only market modelling is presented first. Both CRMs are then introduced.

6.3. Modelling of the energy-only market

Figure 57 describes in a simplified way how the energy-only market is modelled. The different stages are described thereafter.

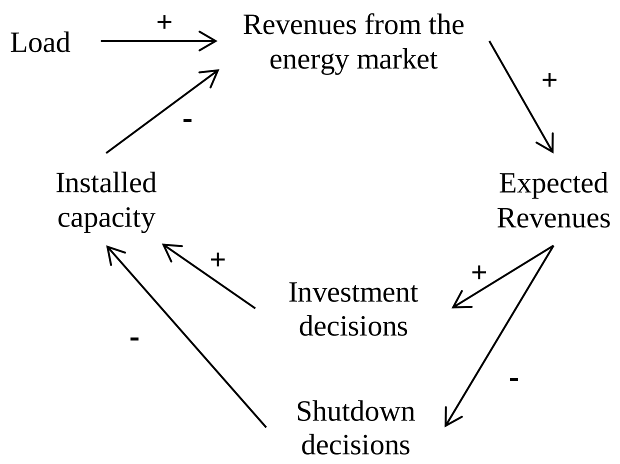

Figure 57: Simplified diagram of the energy-only market

Revenues from the energy market

Revenues from the energy market are computed in the same way as Hobbs et al. (2007) did. They considered that the annual gross margin, defined as revenues earned from the energy and ancillary services markets minus annual variable costs, can be expressed as a function of the ratio of installed capacity over peak load (figure 58). The smaller this ratio is, the larger profits are, since capacity becomes scare and expensive solutions (e.g. demand response) or shortages are needed[130]. The curve used by Hobbs has been defined based on data from the PJM market.

[130] This curve replaces the need to model the whole short-term market and then to consider the demand duration curve and the generation mix. Moreover, Hobbs et al. (2007) considered that power plants always earn a minimum revenue, regardless of the actual ratio, thanks to the ancillary services they provide (and which are not modelled).

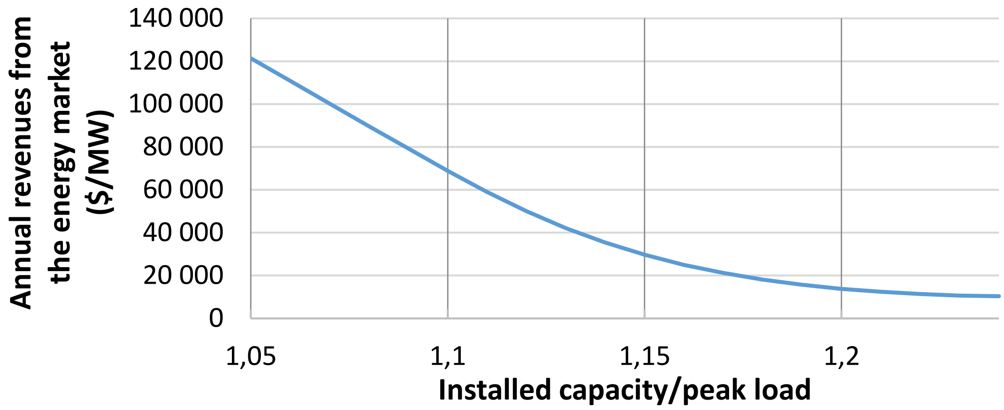

Figure 58: Revenues from the energy market (from Hobbs et al. (2007), based on PJM system)

Investment and shutdown decisions

To decide whether they invest or close plants, market players have to assess the future profitability of their power plants. Since four years are necessary to build a plant, investment decisions are made four years ahead. To simplify the model, the same assumption is made for plant closures. Figure 59 describes the different steps of the decision process, which are explained below.

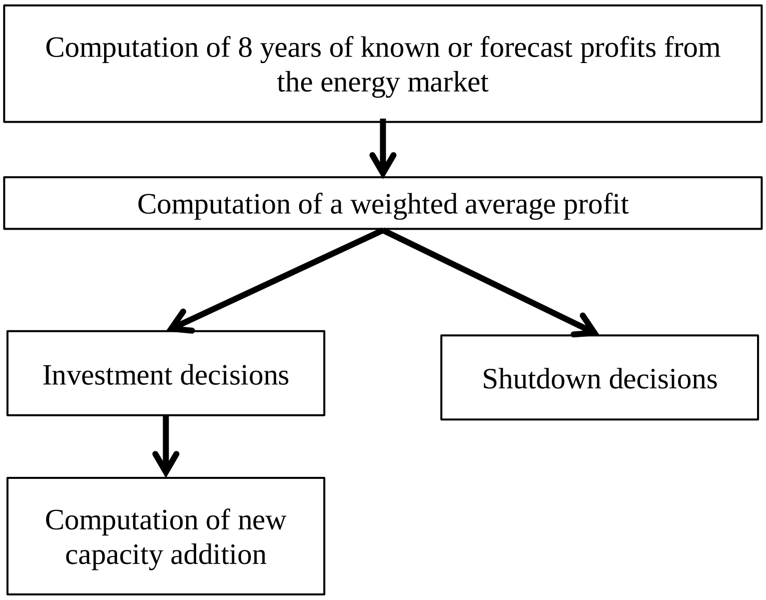

Figure 59: Steps of the investment and shutdown decision process

First, market players have to compute the expected revenues of their plants from the energy market. As Hobbs modelled it, market players base this computation on past and future revenues. Indeed, market players do not have a perfect foresight of future market outcomes. They usually forecast these future results based on market simulation models for which past history is a critical input (Hobbs et al., 2007). Consequently, backward looking is often used in SD modelling to forecast future prices[131] (Assili et al., 2008; de Vries and Heijnen, 2008; Hobbs et al., 2007; Olsina et al., 2006). In particular, in the modelling, market players base this computation on eight years of past and future revenues on the energy market, from year y-3 to year y+4 (y is the current year when decisions are made). For years y-3 to y, revenues from the energy market are known since those years have already passed or are in process. For future years y+1 to y+3, they are unknown and have to be estimated based on the expected demand and future available capacity. Players can partially anticipate the future demand, based on the peak load during the current year y and the average peak load growth. However, they cannot anticipate the uncertainties due to economic growth rate deviation or weather conditions. Furthermore, the future available capacity can be accurately estimated since investors know plants under construction or which are going to close (as such decisions have already been made four years in advance and often released, through media or TSO reports). For the year y+4, the revenues are assumed to be the same as those during year y+3. Then, investors attach a set of weights to each year of revenues. For instance, they can only consider revenues in year y+4 or they can consider eight years of revenues. Finally, investors compute the weighted average of revenues over these eight years to assess the expected revenues on the energy market.

To model players' decisions regarding investments or shutdowns, a rational economic behaviour is modelled, which leads players to balance their expected revenues on the energy market previously computed and their avoidable costs. As avoidable costs are different considering investments or shutdowns, decisions differ: for investment decisions, avoidable costs are investment, O&M and variable costs; for shutdown decisions, investment costs are sunk and only O&M and variable costs can be avoided. In both cases, as the function used to compute revenues from the energy market (figure 58) already takes into account the variable costs, they are not considered thereafter.

[131] In particular, Sterman, (2009) showed that many economic variables can be explained by considering backward-looking methods only.

For investment decisions, market players compare the expected revenues on the energy market during the expected economic lifetime[132] of the plant with investment and O&M costs. The previously computed revenues are assumed to remain constant during this economic lifetime. Since risk-neutral market players are considered, a net present value (NPV) is computed[133]. If it is positive (expected revenues cover at least avoidable costs), investors decide to add new capacity in the system. Otherwise, no investment decision is made. As done in previous literature, the more investors expect a high profitability, the more they invest, reflecting a likely herd behaviour (Assili et al., 2008; Hobbs et al., 2007; Olsina et al., 2006). However, a saturation level is generally considered to limit annual capacity additions. Since participants expect a high attractiveness for new plants, they are aware of the potential danger of a wave of massive investments[134]. Moreover, when the NPV is slightly negative, some investments are still attractive for players with lower financing or investment costs. According to this reasoning, Hobbs et al. (2007) modelled the investment decisions using a linear relationship between the NPV and the capacity addition (figure 60). This assumption is kept in the modelling. This function is defined by three parameters: the capacity addition when NPV is zero, the maximum capacity addition and the NPV at which this maximum addition is reached. These three values are defined in the next chapter about the input parameters.

[132] As mentioned previously, a fixed lifetime for plants (after which they are necessarily decommissioned) is not considered. However, an economic lifetime is used in this modelling. This economic lifetime enables to compute the O&M costs so that after this age, it becomes cheaper to build a new plant than to keep an old and expensive one. This economic lifetime is also used to compute the NPV of new plants.
[133] With risk aversion, other solutions can be used to assess future profitability, for instance the Conditional Value at Risk (CVaR) (Ousman Abani et al., 2018).
[134] It is particularly true in concentrated market where participants can limit investments to avoid low prices which could endanger their capacities in place. There are also some constraints, in particular financing constraints or land constraints, which can limit investments (Olsina et al., 2006).

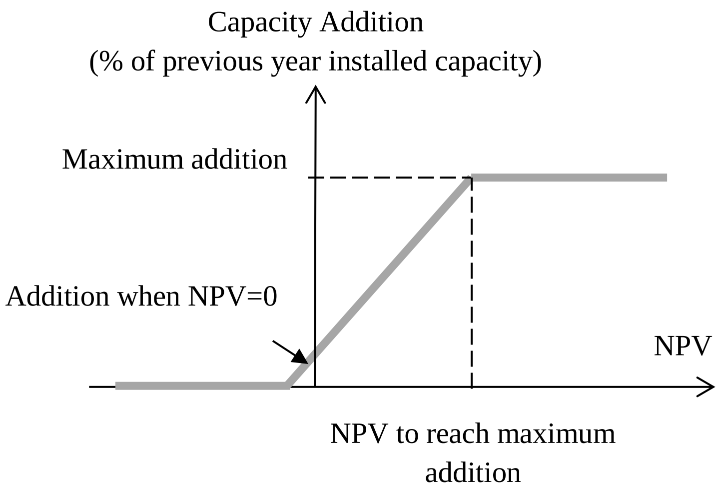

Figure 60: Capacity addition curve

Regarding shutdown decisions, each year, market players decide whether to continue running their plants or to decommission them, considering the expected revenues from the energy market and the O&M costs (which depend on the age of the plant). If these costs appear to be higher than the expected revenues, they decide to close their plants. Otherwise, plants run one more year at least. Moreover, as for investment decisions, a maximal amount of capacity which can be decommissioned each year is considered (players are partially aware of competitors' shutdown decisions and they do not close all their capacity in the same year). At last, once market players have come to a decision about shutdowns and investments, the installed capacity for year y+4 can be determined. Then, the next year demand (y+1) is computed, as well as the actual revenues from the energy market for year y. The decision loop starts again.

6.4. Modelling of the capacity market

Added to the traditional energy market, a new market for capacity is implemented (figure 61). In the modelling, a centralized capacity market is considered (similar to the one implemented in Great Britain or in PJM). Several years ahead, the TSO assesses the optimal level of capacity given the expected peak load. It contracts this capacity through an auction in which market players bid their existing or new capacity. The capacity market is then a quantity-based mechanism which explicitly defines the level of installed capacity to be reached. A capacity price is determined by the market to reach this target: it tends to be high if investments are needed (so that new plants break even) or low otherwise, when there is enough existing capacity. Moreover, only plants whose bids are accepted by the capacity market receive the capacity price. Plants with refused bids are decommissioned or their investments are postponed since they do not earn enough to cover their costs. Thus, the capacity market is believed to solve the investment issue in the energy-only market.

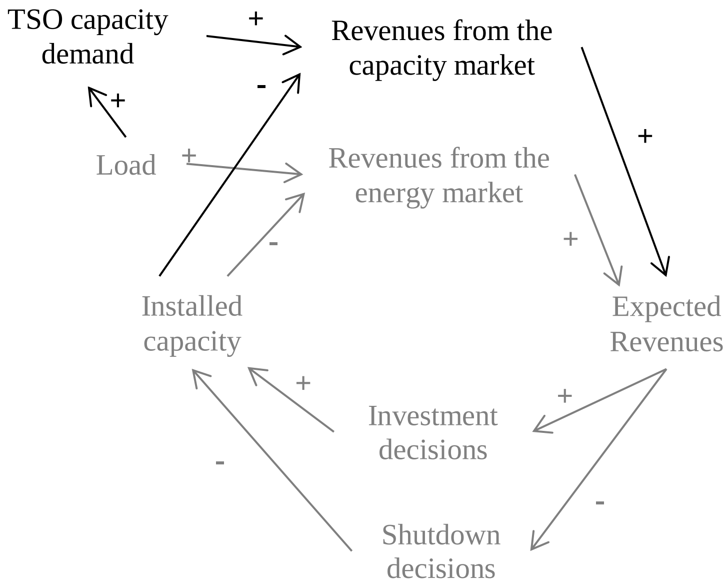

Figure 61: Simplified diagram of the capacity market

Compared to the previous energy-only model, a new step is added to the modelling which simulates the capacity market. The auction for the capacity available in year y is considered to take place four years ahead (which is the lead time for peak technologies) in order to attract new investment if the existing capacity is believed not to be sufficient to reach the target margin. The capacity market is modelled by a supply curve, determined by the offers made by market players (their bidding strategy is described below), and a demand curve, resulting from the TSO capacity requirement (see figure 62). This demand curve is characterized by a maximum price (the price cap) and by a target capacity corresponding to the expected peak demand plus a margin[135]. Matching supply with

[135] The TSO has to procure more than the expected peak load because of the possible outages of plants, which limit their actual availability, and its forecast errors on the evolution of the consumption. Indeed, as for investors in the energy-only market, the TSO has not a perfect foresight of the future load and cannot anticipate future uncertainties due to economic growth rate deviations or weather conditions. This margin is often defined by the TSO based on a probability analysis given different scenarios of forecast errors or outages so that shortages are required only for X% of all simulated scenarios.

demand then determines a price for capacity and the plants which receive this extra-remuneration.

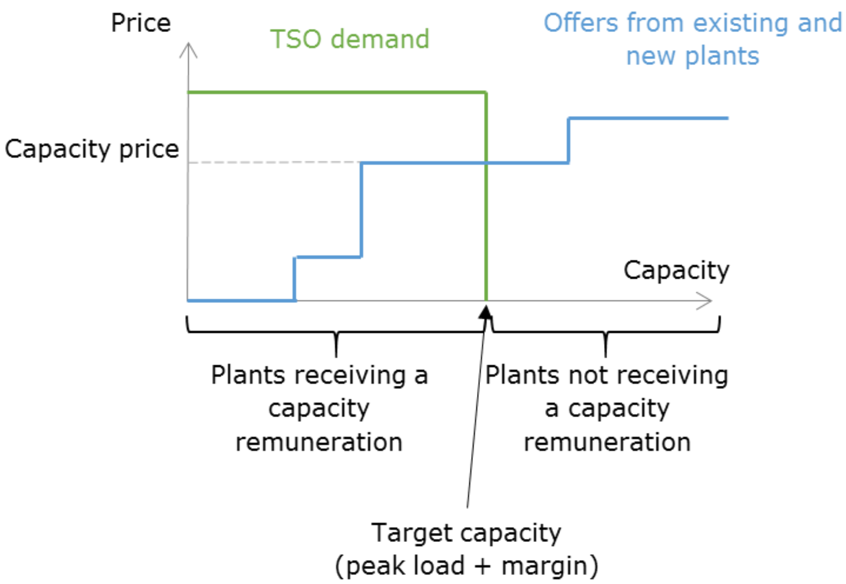

Figure 62: Capacity auction

From the market players' point of view, a more elaborated bidding strategy on the capacity market than the one considered by Hobbs et al. (2007) is developed here[136]. To compute their offers, players have to balance their expected revenues earned on the energy market and their avoidable costs.

- For existing capacity, the only avoidable costs are O&M costs. The economically rational offer price has to guarantee that players cover these costs thanks to revenues from the energy market and from the capacity market. Revenues from the energy market can be estimated as previously, based on the ratio of installed capacity over peak load for eight years. If they are greater than the O&M costs, players bid zero on the capacity market (they do not need revenues from the capacity market to break even). On the contrary, if the expected revenues from the energy market are lower than the O&M costs, market players bid the difference on the capacity market. Thus, if their offers are accepted, they at least cover their avoidable costs (provided that they correctly estimate revenues

[136] Indeed, Hobbs et al. (2007) assumed that existing or new capacity bid at a fixed and exogenous capacity price, independently from their missing revenues. In particular, in the base case they studied, they considered they all bid at a zero price.

from the energy market). In all cases, players offer all their available capacity (i.e. their existing capacity).

• For new plants, contrary to existing capacity, investment decisions are still pending and investment costs are considered as avoidable. Expected revenues during the economic lifetime of assets have to cover both investment and O&M costs. Then, the expected revenues from the energy market (computed in the same way as for existing capacity) are compared with the annualized investments costs and the annualized O&M costs. If these expected revenues are greater than these costs, market players do not need a capacity revenue to break even and then bid zero on the capacity market. Otherwise, investors bid the project’s missing money, i.e. the difference between the annualized costs (considering both investment and O&M) and the expected annual revenues from the energy market. Moreover, it is assumed that investors always offer the maximum capacity addition, as defined in figure 60, on the capacity market (which can be totally or partially refused according to capacity demand and offers from existing capacities). Indeed, the offers made by market players on the capacity market are not definitive investment decisions. In particular, if these offers are not accepted by the capacity market, market players do not to invest since they do not receive the capacity price needed to break even. Consequently, they are assumed to offer a large volume of new investments on the capacity market since they face less uncertainties regarding investment decisions. If bids of new investments are not accepted, market players do not have to invest. If these bids are accepted, market players receive the capacity price to cover their investment costs. In both cases, risks linked with investment decisions are reduced which explains the high volume of investments bids with this design.

Therefore, having computed the supply and demand curves, a capacity price can be determined by the market reflecting the intersection of both curves. This price is not determined by the TSO itself but by the market in order to reach the target level of installed capacity. Based on the results of this market, players with accepted offers invest or keep their plants in operation (since they expect to cover their avoidable costs thanks to the capacity price). Players with refused offers close their plants or do not invest since they are not expected to be profitable.

6.5. Modelling of the strategic reserve mechanism

A strategic reserve mechanism, as described in a simplified way in figure 63, consists in a set of generation units kept available for emergencies by an independent agent, typically the TSO. Contracted plants are taken out of the energy market and are only activated to produce in last resort to avoid shortages. The volume of required strategic reserves is defined by the TSO based on the difference between the expected installed capacity (resulting from the decisions of market players) and the optimal level of installed capacity. These reserves are procured thanks to an auction.

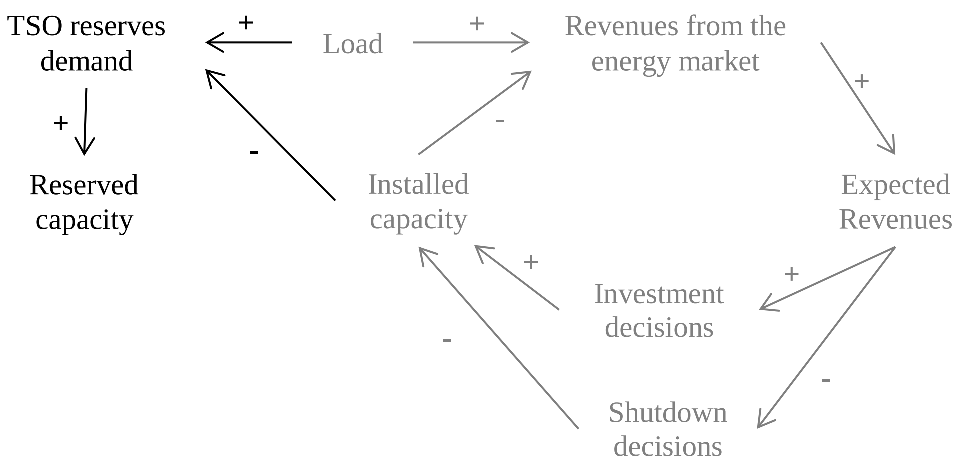

Figure 63: Simplified diagram of the strategic reserve mechanism

Therefore, power plants can be sorted into two exclusive markets: one for strategic reserves, called strategic reserve mechanism below, and one for non-reserved capacity, called energy market below. These markets are exclusive since a plant cannot produce in the energy market and be a strategic reserve at the same time. Revenues earned by a plant on the energy market only come from the production it sells on this market. Reciprocally, reserved capacity cannot sell energy on the energy market, except in last resort when the TSO requires it: its mains revenues come from the auctions for procurement of strategic reserves. Conditions of deployment and use of the reserved capacity have to be well defined to minimize interferences with the energy market. In particular, the trigger price at which strategic reserves are deployed acts as a price cap on the energy market (Finon et al., 2008). If the trigger price is lower than the highest supply bid, it increases the disincentives to invest for producers on the energy market. Here, the strategic reserves are assumed to be deployed and activated by the TSO when there is no more available capacity on the energy market and they are sold at the energy market price cap. Therefore, for a producer on the energy market, there is no difference in its revenues in times of shortage or when strategic reserves are deployed since the energy price is defined at the same value in both cases. The only difference lies in the level of required shortages: without reserved plants, some shortages are necessary if plants available on the energy market are not sufficient to meet load. With strategic reserves, these plants can produce as a last resort to compensate the insufficient level of plants on the energy market and no shortages (or less) are needed.

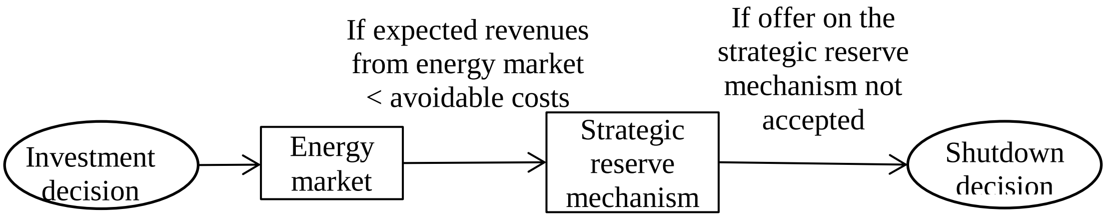

Figure 64: Energy market and strategic reserve mechanism

Figure 64 illustrates how these two exclusive markets are modelled, as well as the links between them and the investment and shutdown decisions. It is considered that market players invest only on the energy market. Indeed, investments on the strategic reserve mechanism seem too risky since 1)the price on this mechanism is guaranteed for only one year (in particular, the TSO may not need strategic reserves for the following year) and since 2) it is assumed that once a plant enter into the reserve mechanism it cannot return to the energy market[137]. Once investment decisions have been made, plants participate in the energy market year after year until they anticipate that their expected revenues from the energy market will be lower than their O&M costs (their avoidable costs). Thus, players attempt to pass their capacity on to the strategic reserves and make offers for their plants on the strategic reserve mechanism. If their offers are not accepted by the TSO, plants will be decommissioned. Otherwise, plants become reserved capacity and they make offers every year on the strategic reserves auctions until their offers are ultimately refused by the TSO, at which point they are decommissioned.

[137] This is necessary in order to insure the credibility of this mechanism and reduce the distortions in the energy market (Neuhoff et al., 2016).

Regarding the functioning of the energy market, there is no major difference with the energy-only market described previously. Since strategic reserves are considered to be deployed only when the available plants on the energy market are not sufficient to meet the peak load and since they are sold at the energy market price cap, existing plants on the energy market generate the same revenues no matter whether shortages happen or whether strategic reserves are activated. Thus, the revenues earned on the energy market can be computed thanks to the function used for the energy market, provided that the ratio used as input is computed with the capacity available on the energy market, and not with the total system capacity (which includes the reserved capacity). For instance, if there is 5 GW of plants selling energy on the energy market and 1 GW of strategic reserve, the total system capacity is equal to 6 GW[138]. However, to compute revenues from the energy market, only 5 GW are considered as an input of the figure 65 since it is assumed that the 1 GW of strategic reserves does not modify the revenues on this market (in particular they do not tend to reduce them). Consequently, for a same level of total installed capacity, revenues from the energy market are higher with the strategic reserve mechanism than with an energy-only market since, in the former case, strategic reserve should not be considered in the ratio used as an input of the figure 65 [139].

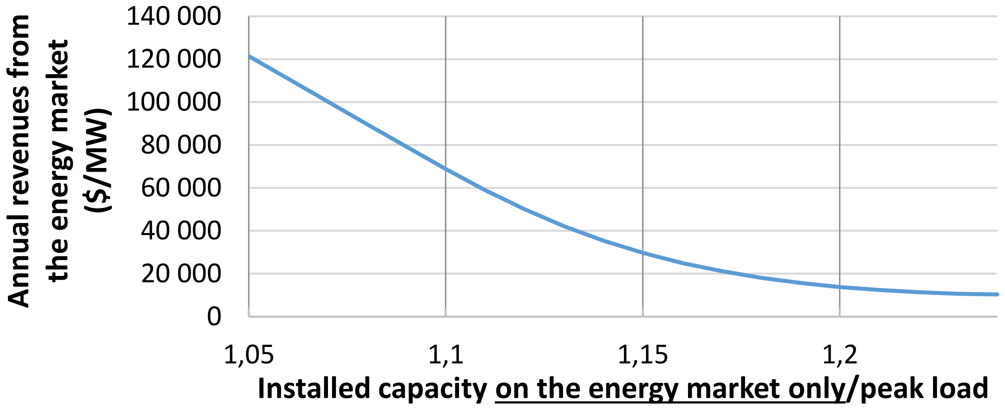

Figure 65: Revenues from the energy market with a strategic reserve mechanism

As previously, generation companies compute an expected revenue on the energy market based on past and forecast revenues and decide consequently to invest or to decommission

[138] Shortages are then reduced compared to a situation without strategic reserves when only 5 GW are available.
[139] However, revenues are the same if the TSO did not procure any strategic reserves.

their plants four years ahead based on their avoidable costs (with the same parameters as for the energy-only market, in particular the capacity addition curve in figure 60).

The strategic reserve mechanism works differently. Every year, to ensure that the system has enough installed capacity to reach an optimal level of shortages, the TSO procures and remunerates some plants which will produce only at last resort. First, four years ahead, the TSO estimates the future demand[140] and the future installed capacity on the energy market (the TSO is assumed to hold auctions once players have made their investment or shutdown decisions on the energy market so it knows exactly the future available capacity four years ahead). If the TSO expects that the margin will be lower than the target margin, auctions are organized to contract enough strategic reserves so that the total installed capacity (considering capacity on the energy market and the strategic reserves) reaches this target. However, the TSO cannot contract an extensive volume of reserves compared to the existing capacity (the energy market would be highly distorted if a large share of plants were reserved and removed from it to become strategic reserves). Thus, a maximal volume of reserves is considered in the modelling (see the next chapter for the considered parameters). Regarding the supply side of the strategic reserve auctions, two categories of market players can bid on these reserves auctions: those which have capacity on the energy market and which have decided to quit the energy market (because the expected revenues on the energy market are not high enough to break even) and those which have already capacity on the strategic reserve mechanism and which want to remain there one more year. Players bid their avoidable costs[141], i.e. their O&M costs, and offer all their available capacity. If their offers are accepted, they at least cover their avoidable costs and then they keep their plants available as reserved capacity for at least one additional year (either they enter the reserve mechanism if they are coming from the energy market, or they stay in the reserve mechanism, if they were already part of it). All the capacities that saw their bids rejected (either because they are too expensive compared to other bids or because the TSO does not need any reserves that year) are permanently shut down since they cannot cover their avoidable costs.

[140] As for the capacity market, the TSO has not a perfect foresight of the future load and cannot anticipate the future uncertainties due to economic growth rate deviation or weather conditions

[141] Reserved capacities are assumed to be paid their variable costs when they are required to produce by the TSO. Thus, they do not make any revenues by selling energy and their sole revenues to cover their O&M costs come from the auctions.

Chapter 7. Results of the simulations and comparison of the effectiveness of the capacity market and the strategic reserve mechanism

<u>Résumé du chapitre 7 en français</u> :

Les modélisations du marché *energy-only* et des différents mécanismes de capacité sont simulées pour une période de 30 ans et pour 500 scénarios d'évolution de la demande. Une analyse de sensibilité sur plusieurs paramètres d'entrée est également menée étant donné l'incertitude sur le niveau de plusieurs d'entre eux. Ces simulations conduisent globalement toutes aux mêmes conclusions.

Un premier résultat met en avant la présence de cycles d'investissements avec un marché *energy-only* et l'incapacité du prix de l'électricité seul à envoyer les bons signaux d'investissements. Lorsqu'un mécanisme de capacité est mis en place (marché de capacité ou mécanisme de réserves stratégiques), ces cycles sont considérablement réduits. Pour le marché de capacité, le niveau de capacité installée est toujours égal au niveau cible. Cela s'explique par la présence d'une définition explicite du niveau de capacité à atteindre dans le fonctionnement du marché de capacité, ce qui contribue à modifier les décisions d'investissements et de fermetures des acteurs via le prix de la capacité. Ce prix de la capacité, qui évolue pour atteindre la cible, vient compléter les revenus de l'énergie et renforce les signaux d'investissements ou de fermetures. Pour le mécanisme de réserves stratégiques, bien que les phases de sous capacité soient fortement réduites, elles peuvent ne pas disparaitre totalement pour certaines années. Cela s'explique par l'absence d'une cible explicite qui pourrait modifier les décisions des acteurs comme pour le marché de capacité. Ces décisions sont toujours basées uniquement sur le prix de l'énergie et peuvent conduire à des décisions non optimales, comme pour le marché *energy-only*. Toutefois, contrairement à ce dernier, le GRT peut réagir en cas de sous-investissements en contractualisant des réserves pour éviter des délestages trop forts. Le GRT peut cependant être limité dans le volume de réserves qu'il peut contractualiser (afin de ne pas distordre trop fortement le marché de l'énergie) et ainsi ne pas réussir à atteindre totalement la capacité cible. Par ailleurs, il ne peut pas forcer les centrales à fermer et les phases de

surinvestissements ne peuvent être évitées. Ainsi, le marché de capacité apparaît plus efficace d'un point de vue du critère d'adéquation et permet de mieux limiter les délestages que le mécanisme de réserves stratégiques.

Les simulations permettent également d'étudier les coûts de chaque mécanisme (coûts d'investissement et coûts de maintenance). Ces coûts sont en moyenne plus élevés avec un mécanisme de réserves stratégiques qu'un marché de capacité. Ce résultat s'explique tout d'abord par la présence de phases de surcapacité uniquement dans le mécanisme de réserves stratégiques. Il s'explique également par l'âge des centrales présentes dans le système électrique. Avec un marché de capacité, ces centrales sont en moyenne plus jeunes et ferment plus tôt. Cela s'explique par l'arbitrage entre les centrales via les offres formulées sur le marché de capacité. Cela permet de coordonner les décisions d'investissements et de fermetures. Les offres sur le marché de capacité des centrales existantes augmentant avec leur âge, elles deviennent plus élevées que les offres des nouvelles centrales au bout d'un certain nombre d'années. Les vieilles centrales deviennent alors non compétitives et ferment car elles ne peuvent plus couvrir leurs coûts, et de nouvelles centrales sont construites. Au contraire, cet arbitrage est moins efficace dans le mécanisme de réserves stratégiques car il ne repose que sur le prix de l'énergie et aucune comparaison directe des coûts des nouvelles centrales et des centrales existantes n'existe. Les centrales existantes peuvent alors rester plus longtemps sur le marché de l'énergie, augmentant les coûts de production. De plus, cet arbitrage entre centrales existantes et nouvelles centrales n'est pas possible pour les centrales réservées par le GRT pour éviter les délestages. Celles-ci sont forcément de vieilles centrales qui ont quitté le marché de l'énergie précédemment. Leurs coûts sont donc importants.

En conclusion, il apparaît que, dans le mécanisme de réserves stratégiques, le recours au seul prix de l'énergie comme outil pour coordonner les décisions d'investissements et de fermetures et pour atteindre un niveau optimal de délestages conduit à de moins bons résultats en termes d'adéquation et de coûts. Au contraire, dans le marché de capacité, l'ajout d'un deuxième marché avec une définition explicite de la cible à atteindre permet de coordonner les différentes décisions et d'atteindre un niveau optimal de délestages : cela explique les meilleures performances économiques du marché de capacité d'un point de vue dynamique.

In a first section, the input parameters used for the simulations are introduced. Then, the way simulations are performed are described. In the remaining sections, results of the simulations are discussed. More precisely, in a third section, the cyclical tendencies in the three market designs are studied. Then, cost-effectiveness and adequacy-effectiveness comparisons are introduced for both CRMs. Finally, the robustness of the results is assessed through a sensitivity analysis.

7.1. Input parameters used for the simulations

Most data used in the modelling are the same as Hobbs et al. (2007), based on the PJM system. As the aim of this study is not to predict future evolutions of a precise power system but to compare different market designs, these data are reused. Table 12 presents the main parameters considered for the reference case. This case is taken as an illustrative case study, with specific characteristics. In particular, it can be noticed that the missing money with the reference case is important given the costs of a new plant (the annualized investment costs are around $70,000/MW) and the revenues earned on the energy market when the margin is equal to the system target margin (around $30,000/MW according to the figure 58). A sensitivity analysis will be performed in section 7.5 to study other alternative and possible cases.

Table 12: Parameters of the reference case

	Parameters	Value for the reference case
Load	System target margin	15% of peak load
	Peak load growth	1.7%
	Peak load growth standard deviation	1%
	Weather standard deviation	4%
Costs	Investments costs[142]	$600 000/MW
	Economic lifetime	20 years
	WACC	10 %
	O&M costs	See figure 66 below
Behaviour of market players	Years considered to compute expected profits for investment and shutdown decisions	y-3 to y+4 (y is the year when decisions are made)
	Weight given to each year profit to compute average profit for investment and shutdown decisions	Each year has the same weight
	Maximum capacity addition (see figure 67 below)	7% of previous year installed capacity
	NPV to reach maximum capacity addition (see figure 67 below)	$600 000/MW (=investment costs)
	Capacity addition when NPV=0 (see figure 67 below)	1.7% of previous year installed capacity (= peak load growth)
	Maximum capacity shutdowns	Considered equal to the maximum capacity addition
Market design	Maximum amount of strategic reserves[143]	15% of the previous year installed capacity

[142] Based on Petitet (2016).
[143] For instance, in Sweden, reserve capacity cannot exceed 2.000MW (compared to a peak load of about 25.000MW) (CREG, 2012).

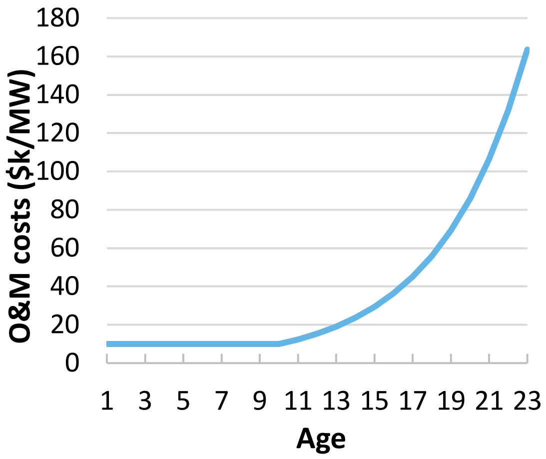

Figure 66: Evolution of the O&M costs in function of age of plants

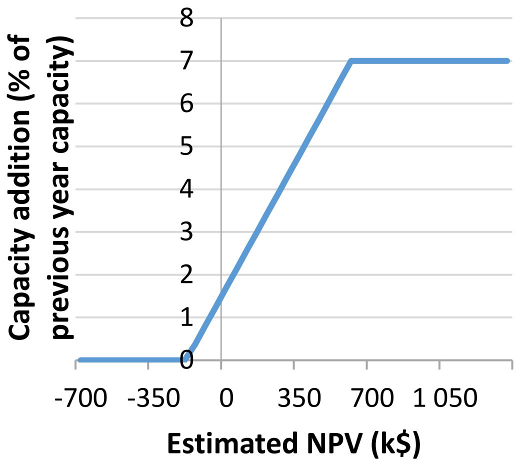

Figure 67: Capacity addition curve for the reference case

<u>O&M costs</u>

O&M costs are assumed to be constant during the first half of the assumed economic lifetime of the plant and exponentially increase after, reflecting the aging of power plants (figure 66). For the reference case, the annual O&M costs are considered equal to $10,000/MW during the first ten years[144]. Moreover, maintenance costs are assumed to be close to the annualized cost (considering both investment and O&M costs) of the plant at the end of its economic lifetime (20 years). Then, after 20 years, market players prefer building a new plant to keeping the existing one and paying high O&M costs.

7.2. Simulations

The model is implemented on Matlab®. It is run for 30 years, for the three market designs. Afterwards, some economic indicators (cf. section 7.4) are computed to assess the performances of each market design over the last 25 years of simulation. This time horizon is consistent regarding the current literature (de Vries and Heijnen, 2008; Hasani

[144] For instance, Petitet (2016) considered annual O&M costs of €10,000/MW and The Brattle Group, (2014) considered values between $14,000/MW and $25,000/MW. However, in both references, these costs are constant during the lifetime of the plant.

and Hosseini, 2011; Olsina et al., 2006). The first five years of the simulation are overlooked to avoid any potential transition effects due to the initialization.

Moreover, as two kinds of uncertainties are introduced in this model[145], Monte Carlo simulations are run to compare the performances of both CRMs under various demand growth scenarios. For each simulation (i.e. for the 30 studied years), 60 random variables are drawn (one for each uncertainty and for each year). The model is then run for the three market designs over these same 30 years of peak load and indicators are computed and compared. Differences in the results are only due to differences in terms of market design. This process is repeated 500 times: these 500 simulations are called scenarios below.

7.3. Study of the cyclical tendencies in the three markets

The cyclical tendencies of the system margin is assessed for the three market designs in this section. The evolution of this margin (computed as the total installed capacity, i.e. capacity on the energy market + strategic reserves if any over the peak load) for one scenario of load growth is studied. Two different system margins can be computed, regarding whether the actual peak load or the expected peak load (as computed at the time when decisions are made) is used. Performances regarding adequacy depend on two factors: 1) how markets provide adequate incentives to have enough installed capacity regarding the expected peak load (i.e. to reach the target capacity) and 2) how this expected load differs from the actual load. This second point does not depend on the considered market design, but only on random deviations. Thus, to perfectly understand how markets work, a focus is made on the first factor and on the expected system margin. Figure 68 describes the evolution of the expected system margin for 25 years of one scenario of load. For the strategic reserve mechanism, the margin on the energy market (i.e. without considering the strategic reserves) is also plotted.

[145] Economic growth rate deviation and weather conditions are modelled thanks to two independently distributed normal random variables with mean zero and whose standard deviations are introduced in the Table 12.

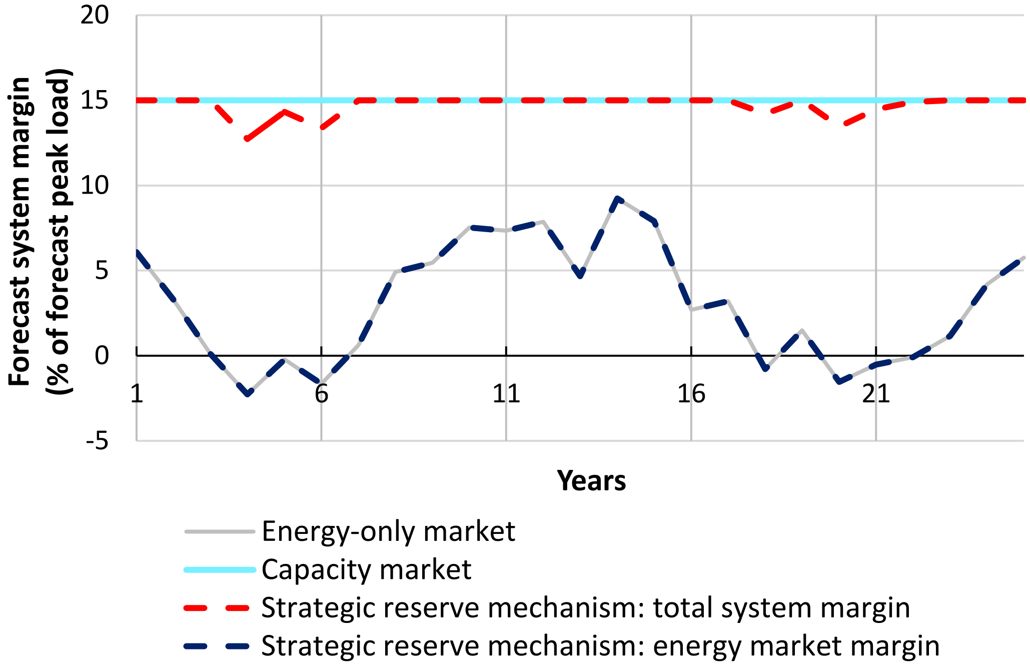

Figure 68: Evolution of the expected system margin for one scenario of load growth in the reference case

The adequacy performances of each market present major differences. With this scenario, the energy-only market experiences high cyclical investment and shutdown decisions. They are mainly due to the herd behaviour and incomplete information (about future load and competitors' decisions). Compared to the results available in the literature, these cycles are here exacerbated since endogenous decommission is considered. If low profits are expected, market players tend to close their plants which makes the margin decrease quickly (and more quickly than in current literature where plants cannot be decommissioned if profits are low). Moreover, the average margin on the energy-only market is around 3 %, which is well below the 15% target margin. Indeed, revenues earned on the energy market when the margin is equal to 15% are not high enough to attract new investments (revenues for this target margin are around $30,000/MW while the annualized investment costs are around $70,000/MW). Thus, the implementation of a CRM is required if policy makers want to reach the target margin and avoid shortages. Moreover, for this scenario, the energy-only market does not experience any overcapacity phases. This is explained both by the low revenues from the energy market (which limit investments) and the low annual capacity addition (cf. figure 67). Consequently, overcapacity is very unlikely with this simulation.

When a capacity market or a strategic reserve mechanism is implemented, the cyclical behaviour is well reduced and the expected margin is more often equal to the target margin. For the capacity market, the system margin is always equal to the 15% target margin. This result seems logical since the capacity market explicitly defines a capacity target. To reach this target, the capacity price evolves depending on the capacity bids made by market players. If there is not enough capacity, the capacity price rises so that new plants or existing plants break even. On the contrary, if there are too many plants, the price decreases and only part of the capacity bids are accepted and remunerated. Consequently, expensive and old plants shutdown because they do not cover their high O&M costs.

The results of the strategic reserve mechanism (the "total system margin" line), if better than those of the energy-only market, show a lesser ability of this CRM to reach the target compared to the capacity market. Indeed, in the energy market of the strategic reserve mechanism, there is no explicit target for the system margin and the energy price is the only signal to coordinate decisions and to give incentives for investments or shutdowns, like in the energy-only market. Therefore, this price leads to the same consequences as in the energy-only market, i.e. a cyclical behaviour and a mean margin well below the 15% target. It can be noticed with the "energy market margin" line which describes the decisions made on the energy market of the strategic reserve design and which is exactly the same as the system margin experienced in the energy-only market. Indeed, since the strategic reserves are assumed not to modify the revenues on the energy market, the same investment and shutdown decisions are made in both market designs. However, contrary to the energy-only market, the TSO is able to react as a last resort by contracting strategic reserves to avoid shortages in case it expects under capacity phases. Thus, these phases are reduced compared to the energy-only market, but in a less effective way than the capacity market since the total system margin is not always equal to the 15% target margin. This is mainly explained by the maximum level of strategic reserves that the TSO can contract to avoid disturbing the energy market (15% of the existing capacity in the reference case), which limits the ability of the TSO to reach the target margin. In this reference case and for the reasons mentioned previously, the energy-only market does not experience any overinvestment phases (i.e., phases with a margin higher than the target); consequently, the strategic reserve mechanism does not result in overcapacity either.

The actual system margin (computed as the total installed capacity over the actual peak load) is presented in figure 69. As explained previously, actual margins are different from the expected ones due to growth uncertainties and then the functioning of CRMs and the cyclical behaviour are less perceptible. However, the same general conclusions can be drawn when assessing the actual system margin: both CRMs reduce the underinvestment phases prone to appear in the energy-only market.

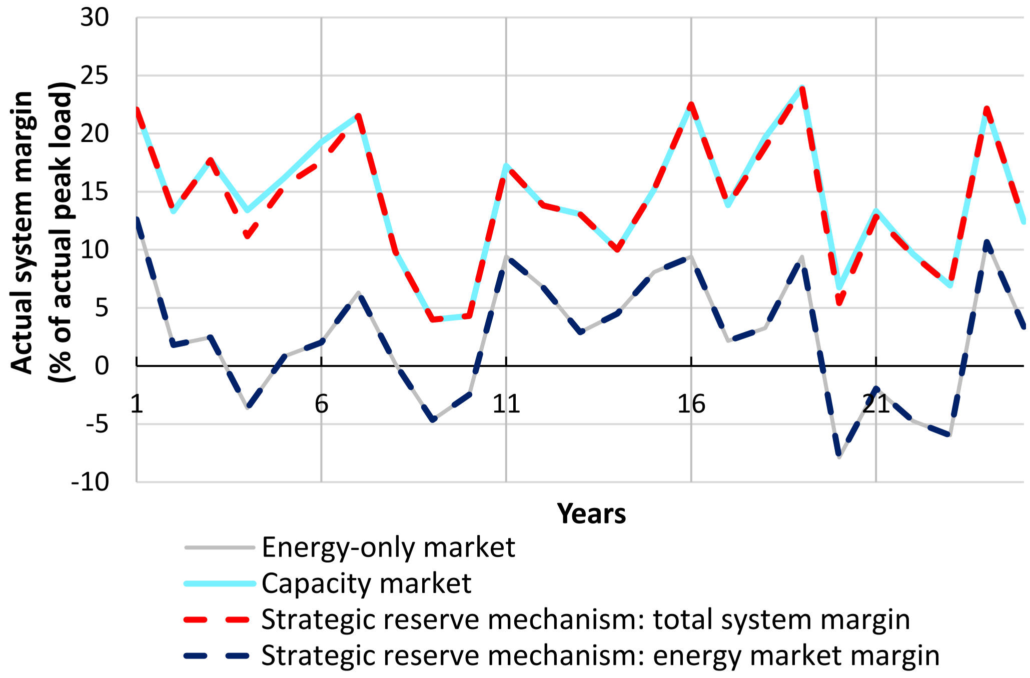

Figure 69: Evolution of the actual system margin for one scenario of load growth in the reference case

7.4. Economic comparisons of the capacity market and the strategic reserve mechanism

The analysis of previous results shows that the capacity market seems to be more adequacy-effective (i.e. it results in a system margin closer to the target than both other market designs), for one specific random scenario. However, the cost effectiveness of the mechanisms (i.e. their costs) should also be compared to assess correctly the economic performances of both CRMs.

Indeed, from an economic point of view, social welfare should be used and compared to select the best CRM to implement. Since demand is considered as inelastic in the modelling, performances of CRMs can be compared only through the cost of shortages and the costs of generation (de Vries, 2004). In the modelling, to simplify, instead of shortage costs, the difference between the system margin and the target margin are measured: a system margin lower than the target margin would imply some shortages provided that the TSO has correctly estimated the target margin[146]. This indicator is referred to as the adequacy effectiveness in the remaining sections. For each year of the simulation, the difference between the system margin and the target margin is computed (as % of the peak demand). An average value over the last 25 years of the simulation is then calculated[147]. At the end, the result stands for the mean difference between the system and the target margin by year as % of peak demand. The higher this value, the more shortages are likely and then the lower the performances of the CRM.

The generation costs are estimated by computing the annualized investment and O&M costs[148]. For each year, these costs are computed and divided by the peak demand. Then, the average value is calculated over the last 25 years of simulation. The final result is expressed in $/MW of peak load per year. This indicator is referred to as the cost-effectiveness indicator.

Five hundred Monte Carlo simulations of demand growth scenarios are run. For each scenario, the cost-effectiveness difference between both CRMs is computed, as well as the adequacy-effectiveness difference. Then, both differences are displayed in a figure similar to the figure 70, based on their signs. Each point depicts the cost-effectiveness and adequacy-effectiveness differences compared to the capacity market for one scenario

[146] In theory, shortage costs can be computed by assuming a cost for load reduction, known as VOLL in literature, and by computing the level of shortages. However, since demand is only characterised by its peak level and not an overall duration curve, it is not possible to compute easily the volume of shortages (in fact, supplementary assumptions would be needed to determine this volume). Moreover, there is no consensus on the VOLL value in the literature. To avoid giving a larger weight to shortages or generation costs (by assuming an inadequate VOLL value and/or by computing an inadequate volume of shortages), these two values are assessed separately.

[147] Moreover, if the system margin is greater than the target margin, the difference is capped at zero so that, in the average value of the adequacy-effectiveness indicator, an overcapacity during a given year does not offset likely shortages during an under capacity phase for another year.

[148] Variable costs are not considered here. Indeed, they are expected to be the same between both CRMs most of the time, except when one market design experiences shortages and the other does not curtail demand. However, variable costs during these hours are insignificant compared to other costs.

of demand growth. Three cases can be identified. In quarter 1, the capacity market is expected to experience less shortages and the total generation costs are lower than with the strategic reserve mechanism; one can conclude on the economic superiority of the capacity market based on these criteria. In the opposite case (quarter 3), the strategic reserve mechanism is a better mechanism. In the last cases (quarters 2 and 4), no conclusion can be directly drawn.

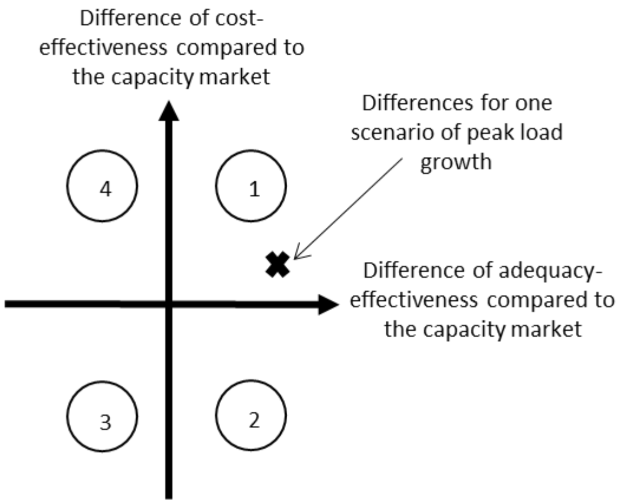

Figure 70: Graphical depiction of the differences in both indicators for each load scenario

The results for the reference case and for the 500 simulated scenarios are displayed in figure 71. Other indicators of both CRMs explaining the differences in performances are also introduced in table 13.

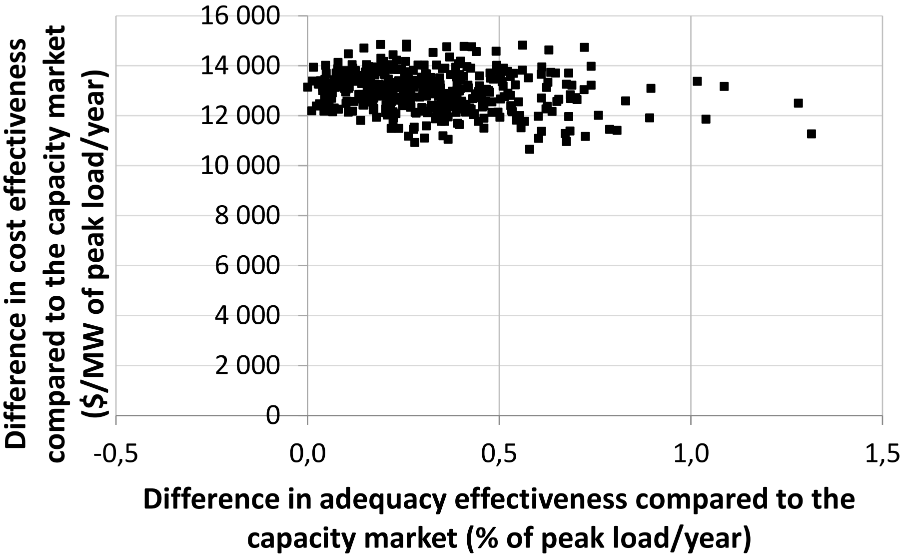

Figure 71: Comparisons of the adequacy effectiveness and the cost effectiveness of both CRMs for the reference case

Table 13: Comparative results of both CRMs for several indicators

	Unit	Capacity market	Strategic reserve mechanism
Average total system margin	% of peak load	15	14.7
Average energy market margin (i.e. without considering strategic reserves)	% of peak load	15	3.2
Maximum energy market margin	% of peak load	15	10
Minimum energy market margin	% of peak load	15	-0.4
Average volume of strategic reserves	% of peak load	-	11.5
Average lifetime of plants on the energy market	Years	20.25	21.8
Average lifetime of plants on the strategic reserve mechanism	Years	-	24.9

For the reference case, all scenarios are in quarter 1, where the capacity market is more adequacy-effective and more cost-effective than the strategic reserve mechanism.

Regarding the adequacy-effectiveness indicator (i.e. the difference between the target and the system margin), the superiority of the capacity market has been explained in the previous section. Even if the strategic reserve mechanism succeeds in providing enough reserved capacity most of the time, the maximum volume of strategic reserves considered in the modelling can limit the reach of the target margin during large under capacity phases. On the contrary, the capacity market always succeeds in reaching this target margin thanks to the explicit capacity demand defined by the TSO. On average, the difference between the target margin and the system margin is about 0.3 % of the peak load per year for the strategic reserve mechanism (and 0% for the capacity market). Then, the strategic reserve mechanism appears less adequacy-effective and is more likely to experience shortages compared to the capacity market. However, it should be noticed that shortages are well reduced compared to the energy-only market, even with the strategic reserve mechanism, then justifying the implementation of a CRM.

Regarding the total generation costs, the superiority of the capacity market is clear. Generation costs are about $13,000/MW of peak load per year higher with a strategic reserve mechanism compared to a capacity market. This significant difference in generation costs is mainly explained by the age of installed power plants in both CRMs. With the capacity market, the average lifetime of power plants is about 20.25 years whereas it is equal to 21.8 years on the energy market of the strategic reserve mechanism (after these 21.8 years, plants can become strategic reserves as explained thereafter).

This result is explained both by the large missing money experienced on the energy market and by the investors' behaviour which tend not to invest enough in the reference case when NPV=0. Consequently, the system margin remains low due to the lack of investments on the energy market and the associated revenues increase following the relationship described with the figure 58. This is a classic reaction of the market to attract more investments. However, these higher revenues also make old and expensive plants break even and stay on the energy market longer than the optimal lifetime (20 years), which explains why power plants quit the energy market after 21.8 years on average in the energy market of the strategic reserve mechanism. These old plants used to produce due to low investments then result in high O&M costs which partly explains the larger generation costs of the strategic reserve mechanism.

Moreover, in the strategic reserve mechanism, the TSO requires a large volume of reserved capacity to avoid shortages because of the large under capacity phases occurring in the energy market (on average, the volume of reserved capacity is about 12% of the peak load). These reserved plants are necessarily plants decommissioned from the energy market[149]: then, their related O&M costs are high since these plants are old. On average, for the 500 studied scenarios, plants quit the energy market after 21.8 years, then become strategic reserves and are definitely decommissioned after 24.9 years. Given the shape of the O&M costs considered in the modelling (see figure 66), the O&M costs of these reserves are significant and also explain the higher costs of this mechanism.

On the contrary, the capacity market exhibits several characteristics which enable to reduce its costs. Firstly, its results are less dependent on the NPV addition curve defined in the figure 67. Indeed, market players are assumed to always offer the maximum capacity[150] (7% in the reference case), which can be partially accepted depending on the results of the capacity market. The capacity market then succeeds in attracting enough investments, contrary to the strategic reserve mechanism.

Moreover, the capacity price plays an important role in this market. This price is determined by the market based on the bids made by market players in order to reach the system target margin defined by the TSO. It evolves, upwards or downwards, to have the exact amount of desired capacity and then modifies market players' decisions so that they invest or decommission their plants. In particular, this capacity price brings new revenues to plants, added to the energy market. Indeed, revenues earned on the energy market with the capacity market design tend to be low[151]: to incentivize market players to invest or to keep their plant online, the capacity price provides extra revenues to market players. Investments are then possible even with low revenues on the energy market contrary to the strategic reserve mechanism which requires high revenues from the energy market and then a low system margin. Finally, within the capacity market, an arbitrage is made

[149] Indeed, due to the associated risks, investments in the strategic reserves are not considered.
[150] Indeed, the offers made by market players on the capacity market are not definitive investment decisions. In particular, if these offers are not accepted by the capacity market, market players do not have to invest. Consequently, they face less uncertainties regarding investment decisions. If bids of new investments are not accepted, market players do not have to invest. If these bids are accepted, market players will receive the capacity price to cover their investment costs. In both cases, risks linked with investment decisions are reduced and market players are assumed to bid the maximum capacity.
[151] These revenues are low since the system margin is close to the target margin: corresponding revenues from the energy market (illustrated on the Figure 58) are lower than annualized investment costs.

between existing capacity and new capacity during the capacity auctions to reach the target defined by the TSO. Indeed, if some plants are too old and therefore more expensive than new capacity (i.e. if their O&M costs for staying on the energy market for one additional year are larger than the annualized investments and O&M costs), these old plants bid a higher capacity price on the capacity market than the new plants. Then, investments are accepted first by the capacity market and old plants tend to be refused by the capacity market. Since they do not receive the capacity price to cover their O&M costs, these plants close. That is why the average lifetime of power plants with the capacity market is about 20 years, i.e. the optimal lifetime after which it is more relevant to close a plant than to build a new one. However, it should be noted that this average age is slightly larger than 20 years in this reference case (20.25 years on average) since, for some years, the maximum capacity addition offered by investors (7%) is not enough. In order to reach the target margin, the TSO has to accept existing plants older than 20 years on the capacity market. In short, the direct comparison of the costs of plants within the capacity auction enables to coordinate investment and shutdown decisions and to reach an optimal lifetime of plants, which is not possible with the strategic reserve mechanism. For instance, with this latter mechanism, when large profits are expected, market players tend both to invest and to keep their old plants online.

To conclude, for this reference case, the capacity market appears to be more adequacy-effective and more cost-effective than the strategic reserve mechanism for all studied scenarios. Shortages are less likely to happen and the total costs of generation are lower.

7.5. Sensitivity analysis

In this section, the robustness of the previous results is tested through a sensitivity analysis. Indeed, the previous comparison was made for a very specific case with several specific characteristics (low investments, high missing money…). Different characteristics and parameters, which can modify the cost effectiveness and adequacy effectiveness of both CRMs are tested here. The alternative cases, presented in the table 14 are run for the same load growth scenarios as for the reference case. Results are also presented in the table 14 in which the average differences in cost-effectiveness and adequacy-effectiveness indicators for the 500 scenarios are depicted as well as the numbers of scenarios in each quarter of figure 70.

In each alternative case, the capacity market is still more cost-effective and more adequacy-effective than the strategic reserve mechanism, since average differences in each indicator are always positive and all scenarios are in quarter 1 or between the quarter 1 and 4 (i.e. same adequacy effectiveness but a higher cost effectiveness of the capacity market). Below, the results of the alternative cases are explained compared to the reference case. As it will be explained, in most cases, performances of the capacity market are almost the same between the reference case and the alternative cases (i.e. the system margin is always equal to the target margin and the average lifetime of plants is about 20 years): the differences between both CRMs are then only explained by different performances of the strategic reserve mechanism. That is why, in these explanations, a focus is made on the strategic reserve mechanism and how the varying parameters impact its performances compared to the reference case

Table 14: Results of the alternative cases

Case		Varying parameter	Value	Mean difference in: Adequacy effectiveness (% of peak load/year)	Mean difference in: Cost effectiveness ($/MW of peak load/year)	Number of scenarios in/on (cf. figure 70)[152]: Quarter 1	Number of scenarios in/on (cf. figure 70)[152]: The line between quarters 1 & 4
Reference		-	-	0.325	12,970	499	1
Different behaviour of market players	1	Capacity addition when NPV = 0	cf. figure 72 below	0.013	866	218	282
	2			0.028	869	287	213
	3			0.003	1,129	75	425
	4	NPV to reach the max. capacity addition	$400,000/MW	0.237	8,273	493	7
	5		$800,000/MW	0.496	18,860	500	0
	6	Years used to compute the expected revenues for investment and shutdown decisions	y to y+4 (y is the year when decisions are made)	0.106	12,777	497	3
Different market conditions and market design	7	Revenues earned on the energy market	Revenues are 20,000 $/MW higher (see figure 74 below)	0.084	10,433	462	38
	8		Revenues are 40,000 $/MW higher (see figure 74 below)	0.009	7,987	188	312
	9	Maximum amount of strategic reserves	30% of the previous year installed capacity	0.001	13,756	50	450
Different costs and technical parameters	10	O&M costs	$15,000/MW during the first 10 years (see figure 75 below)	0.414	12,175	500	0
	11		$20,000/MW during the first 10 years (see figure 75 below)	0.551	11,645	500	0
	12	Lead time	2 years	0.325	12,993	500	0
	13		3 years	0.321	12,985	499	1
Different load	14	Peak load growth	4%	0.152	11,374	485	15
	15		0.5%	1.522	22,477	500	0

[152] For each case, there is no scenario in the other quarters.

7.5.1. Alternative case studying different behaviours of market players

With the alternative cases 1 to 5, the capacity addition curve (i.e. how market players invest) is modified. In the alternative cases 1, 2 and 3, the volume of capacity addition is increased. Indeed, one of the main reasons of the lower performances of the energy market and then of the strategic reserve mechanisms is the low level of investment, which then results in keeping old plants producing. In the modelling made by Hobbs et al. (2007), a capacity addition when NPV=0 equal to the peak load growth (i.e. 1.7%) was chosen and is considered in the reference case. However, in the original modelling, the shutdown of existing power plants was not taken into account. Therefore, new plants were built only to follow the increasing peak load. In the modelling developed in this part, shutdown decisions are considered: consequently, new plants are needed to compensate both the increasing peak load and the decommissioning of old power plants. In the reference case, new investments are unlikely to be sufficient to compensate the decommissioning of old plants. For instance, if the expected NPV is equal to 0, market players invest enough to follow the average peak load growth. However, some power plants close since their O&M costs become too high and these plants are likely not to be replaced by new plants: the system margin remains low since the installed capacity tends to decrease. This results in plants that tend to stay longer than their optimal lifetime[153].

Consequently, in the alternative cases 1, 2, and 3, higher values of capacity addition are considered to offset also the shutdown decisions. For cases 1 and 2, it is assumed that the capacity addition when NPV=0 is equal to 5.9 % of the existing capacity. This value is computed theoretically by considering that the optimal lifetime of power plants is equal to 20 years. In theory, new investments for the year y have to offset the increasing demand for this year but also investments made 20 years before. Similarly, these investments made 20 years before had to offset the increasing demand for that year but also the investments made 20 years before. Repeated indefinitely, this result in a converging series whose sum is equal to 5.9%[154]. This theoretical value is used in the alternative cases 1

[153] This situation does not occur with the capacity market since market players always bid the maximum capacity for investments (see footnote 150).

[154] More precisely, this sum is equal to: $\alpha \frac{1}{1-(\frac{1}{1+\alpha})^{20}}$ with α the average peak load growth (1.7% in the reference case).

and 2 to determine the capacity addition when NPV is equal to 0. Moreover, it seems relevant to also modify the other parameters of this curve. For instance, if the same maximum capacity addition is considered as in the reference case (7%), the shape of the capacity addition curve will be deeply different from the one considered by Hobbs et al. (2007) (in particular the difference between the addition when NPV=0 and the maximum addition will be low, namely 1.1%). Two alternative cases are then studied: in the alternative case 1, the maximum addition is increased by 4.2% (i.e. the maximum addition is equal to 11.2%) so that the difference between the capacity addition when NPV=0 and the maximum addition is the same as in the curve defined by Hobbs et al. (2007) and used in the reference case (i.e. 7-1.7=5.3%). For this case, the same NPV to reach the maximum capacity addition is used (i.e. $600,000/MW). In the alternative case 2, all parameters defining the capacity addition curve are increased by the same factor. Consequently, since the capacity addition when NPV=0 is multiplied by around 3.5 (from 1.7% to 5.9%), the maximum capacity and the NPV to reach the maximum capacity are increased by the same factor. Finally, in the alternative case 3, a capacity addition when NPV=0 higher than the theoretical value computed previously is considered (namely 8%). As for the alternative case 1, the maximum capacity addition is increased so that the difference between both values is identical to the one used by Hobbs and the same NPV to reach the maximum capacity is kept. These parameters are summed up in the figure 72 where they are compared with the reference case.

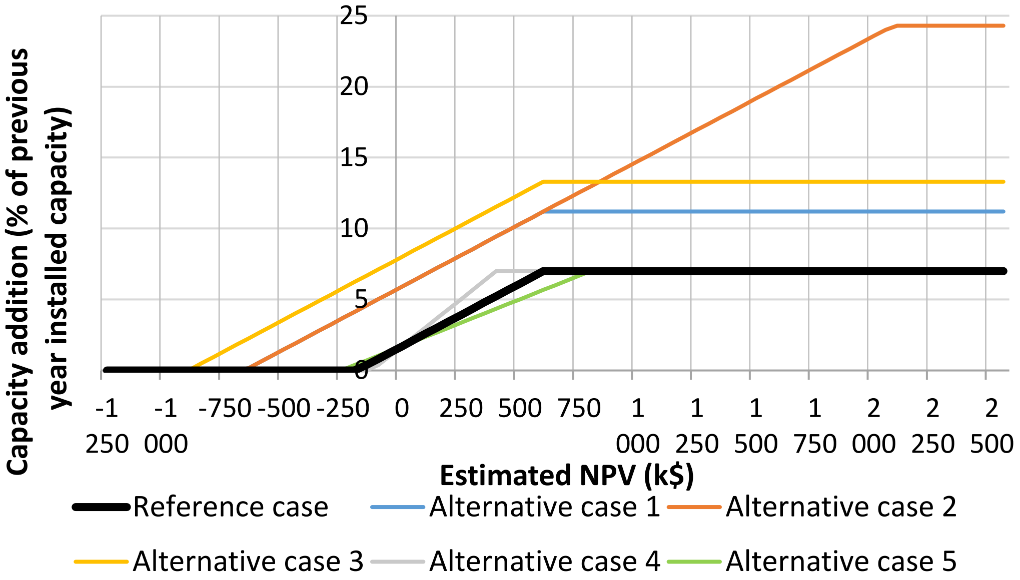

Figure 72: Capacity addition curves in the alternative cases

For these three alternative cases, the cost-effectiveness performances of the capacity market are slightly modified (its adequacy effectiveness is however the same). Indeed, only the maximum value of the capacity addition curve can modify the performances of the capacity market (the other parameters do not modify the bids of new plants on the capacity market). The maximum value defines the volume of investments proposed on the capacity market (which can be refused by the market in case of overcapacity). For the reference case, the average lifetime of plants in the capacity market is slightly higher than the optimal lifetime (20.25 years) since, for some years, the maximum amount of investments submitted in the capacity market is not enough to offset both the increasing demand and the shutdown of old plants. Consequently, to reach the target margin, the TSO has to accept old plants, whose bids are higher than those of new investments (i.e. plants older than 20 years). Then, in the reference case, the average lifetime of plants is not optimal with the capacity market (but closer to the optimal than with the strategic reserve mechanism). In the alternative cases 1 to 3, since a larger volume of new plants can be submitted, this situation does not occur anymore. Investments, combined with existing plants younger than 20 years (i.e. whose capacity bids are cheaper than bids of new plants), are always enough to reach the target margin. Consequently, the TSO does not have to accept bids of existing plants which are more than 20 years old. The average lifetime of plants within the capacity market is then always equal to the optimal lifetime, i.e. 20 years, and the generation costs are then optimal.

On the contrary, in these three alternative cases, the new capacity addition curve has significant impacts on the performances of the strategic reserve mechanism. Indeed, compared to the reference case, for the same expected NPV, market players tend to invest more in these alternative cases (see figure 72) which enables to compensate both the increasing demand and the shutdowns of old plants. Since more investment occurs for the same NPV, the system margin tends to be higher (the average margin is equal to 8% of the peak load for the alternative cases 1 and 2 and to 11% in the alternative case 3). It results in lower revenues on the energy market which forces old plants to shut down since they become unprofitable. In the alternative cases 1 and 2, the average lifetime of plants on the energy market of the strategic reserve mechanism is about 19.6 years, close to the economic optimal lifetime (compared to 21.8 years with the reference case). In the alternative case 3, market players tend to invest even more for the same NPV. Consequently, the average margin is higher: it results in lower revenues on the energy market which force existing plants to close earlier than the optimal lifetime (on average after 18 years). These different average margins also impact the volume of strategic reserves. A higher margin results in less needed reserves to reach the target margin (about 6.5% of peak load in the alternative cases 1 and 2 and 4% in the alternative case 3). Consequently, since less reserves are needed, the limit of the maximum volume of strategic reserves is less often reached in these alternative cases compared to the reference case, which explains why the adequacy-effectiveness indicator is lower (in all cases, the adequacy effectiveness of the capacity market is the same so the differences between the reference case and the alternative cases are only explained by the strategic reserve mechanism). However, the adequacy-effectiveness differences between both CRMs remain positive since the maximum volume of reserved capacity still limits the capacity of the TSO to reach the target margin for some years in the strategic reserve mechanism (while the TSO always succeeds in reaching this target margin with the capacity market).

Regarding the generation costs with the alternative cases 1 and 2, the average lifetime of plants on the energy market is close to the economic lifetime and lower than in the reference case since higher investments force old plants to close. Consequently, generation costs of the strategic reserve mechanism are well reduced compared to the reference case. However, they remain higher than those of the capacity market (i.e. the cost-effectiveness indicator remains positive, even if it is reduced). Indeed, even if the average lifetime of plants is about 20 years on the energy market of the strategic reserve mechanism, they do not close immediately since the TSO needs some of them as reserved plants to avoid shortages. On average, plants are definitely decommissioned after 21.4 years in the alternative cases 1 and 2. The O&M costs of these old reserved plants are then significant and result in suboptimal generation costs compared to the capacity market in which plants are always definitely decommissioned after 20 years.

Moreover, these alternative cases enable to compare the ability of CRMs to deal with overcapacity phases. Indeed, some overcapacity phases are likely to happen in the energy-only market with these higher values of the capacity addition curve (cf. figure 73 for one load scenario) since the average margin is higher than in the reference case. When comparing these phases, it appears that the strategic reserve mechanism does not perform any better than the energy-only market. Indeed, overinvestments are still likely to happen if investors expect large profits from the energy market since there is no signal to avoid this in the strategic reserve mechanism and the TSO cannot force players to postpone their investments or to close their plants. On the contrary, in the capacity market, the capacity price enables to avoid overcapacity phases. Indeed, new or existing capacity (except the younger plants) always bids a positive capacity price, i.e. they always need capacity revenues to break even, since their expected revenues from the energy market are not high enough to cover their costs[155]. If the total offer on the capacity market is higher than the capacity demand defined by the TSO, only part of the bids receives the capacity price (those with the lowest bids). Then, refused plants do not break even and market players decide to close them or postpone their investments. Thus overcapacity phases are avoided in the capacity market. This difference between both CRMs also explain the higher cost effectiveness of the capacity market. Indeed, during the overcapacity phases occurring in the strategic reserve mechanism, more plants than needed are online. Consequently, the associated O&M costs are likely to be higher with the strategic reserve mechanism than with the capacity market for the same peak demand. In particular, the overcapacity phases are more significant for the alternative case 3 (since higher investments occur). It then

[155] The revenues earned on the energy market when the margin is close to the target margin are well below the annualized investment costs or below the O&M costs when the plant is older than 17 years: power plants then always need a positive capacity price to break even.

explains the higher difference in generation costs between both CRMs compared to the alternative cases 1 and 2.

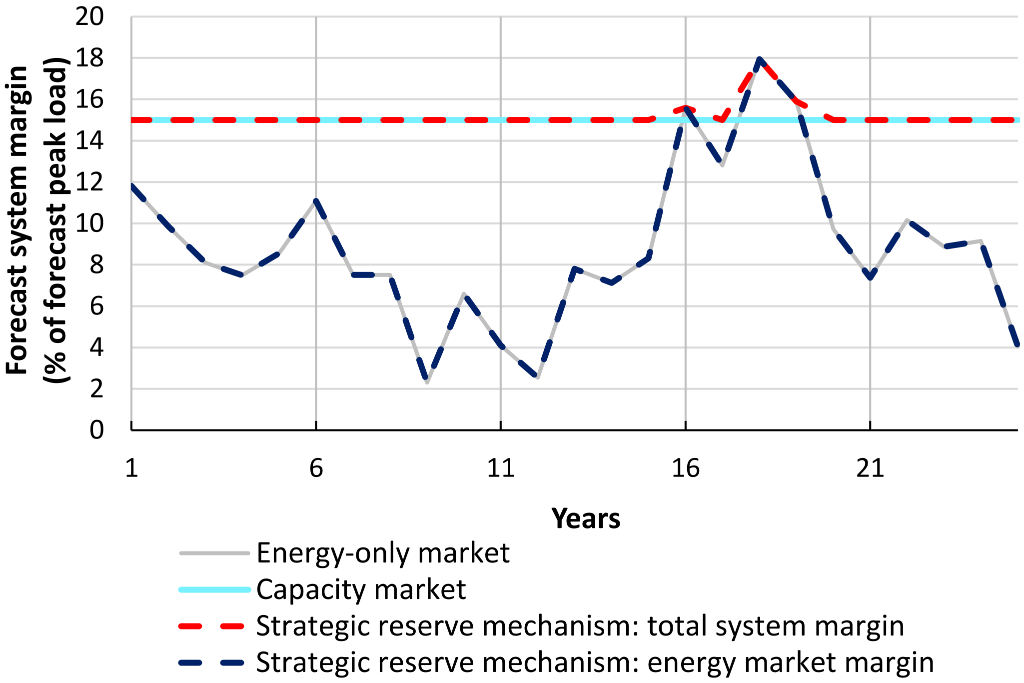

Figure 73: Evolution of the expected system margin for one scenario of load growth in the alternative case 1

With the alternative cases 4 and 5, only the NPV to reach the maximum capacity addition is modified. Performances of the capacity market are exactly the same as in the reference case since this parameter does not intervene in the functioning of this market. Regarding the performances of the strategic reserve mechanism, in the alternative case 4, the herd behaviour of market players is increased (see figure 72): they tend to invest more quickly based on the expected NPV. The under capacity phases of the reference case are then lower since market players tend to reach the maximum capacity addition for a lower NPV and then for lower energy revenues. Consequently, the average margin on the energy market of the strategic reserve mechanism is higher than in the reference case (4.5% vs. 3% in the reference case). As explained previously, it results in a higher adequacy effectiveness since less strategic reserves are required. Moreover, the lower energy revenues force existing plants to close slightly earlier than in the reference case (on average after 21.6 years, compared to 21.8 years with the reference case). Combined with the lower volume of needed reserves, this explains the higher cost effectiveness of the strategic reserve mechanism compared to the reference case. However, it remains less cost-effective than the capacity market since plants are still decommissioned too late compared to the economic lifetime.

The opposite occurs in the alternative case 5. Market players reach the maximum capacity addition for a higher NPV and then invest less quickly. It exacerbates the under capacity phases and decreases the average margin (which is equal to 1.8 % on average). Then, more reserves are needed and the adequacy effectiveness of the strategic reserve mechanism decreases. Moreover, contrary to the alternative case 4, plants quit the energy market later than in the reference case (on average 22.4 years) due to lower investment decisions. Combined with the higher need for reserves, it explains the lower cost effectiveness of the strategic reserve mechanism for this alternative case.

Finally, with the alternative case 6, a different assumption about the years that market players consider to make their forecast about the future revenues is made. It modifies the functioning and the results of both CRMs. Nevertheless, the capacity market is still more cost-effective and more adequacy-effective than the strategic reserve mechanism.

7.5.2. Alternative case studying different market conditions and market design

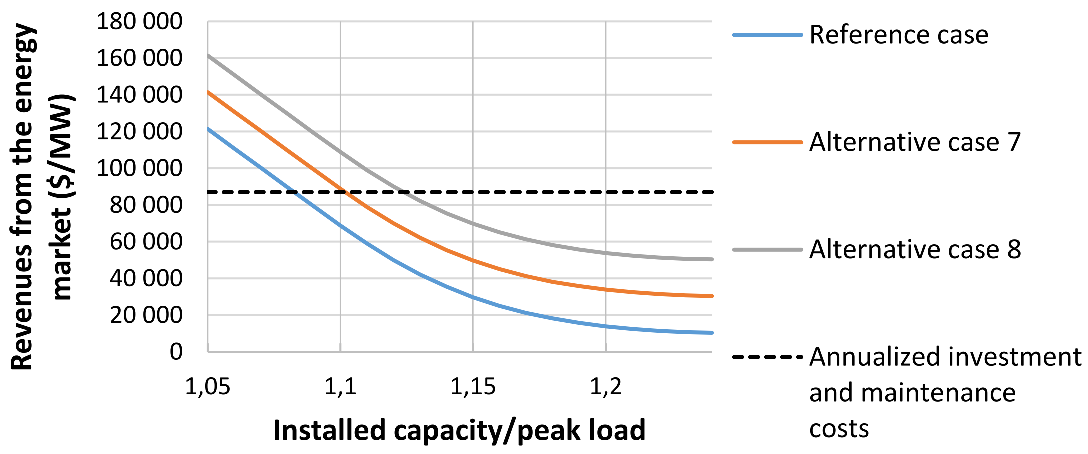

Figure 74: Revenues from the energy market considered in the alternative cases 7 and 8

With the alternative cases 7 and 8, the revenues earned on the energy market are higher compared to the reference case for the same system margin (for instance, in the alternative case 7, revenues are increased by $20,000/MW compared to the reference case, see figure 74). It reflects a power system with a lower missing money compared to the reference case. In these alternative cases, performances of the capacity market are almost the same as in the reference case. Indeed, the higher revenues earned on the energy market are offset by a lower capacity price asked by plants (existing or new ones). In particular, the arbitrage between old and existing plants is still possible by comparing their capacity bids and the average lifetime of plants is about 20 years, resulting in optimal generation costs. However, these new settings deeply modify the performances of the strategic reserve mechanism. Indeed, to attract new investments (i.e. to reach a NPV equal to 0), the margin does not need to be as low as in the reference case since market players earn more in the alternative cases for the same system margin all other things being equal. In the reference case, the average expected margin of the energy market of the strategic reserve mechanism (i.e. without considering the reserved plants) is about 3% of the peak load whereas it is equal to 5% in the alternative case 7 and 7% in the alternative case 8. Consequently, since the margin is higher, less strategic reserves are needed by the TSO and the limit on the maximum volume of reserved capacity is less often reached. It explains the higher adequacy effectiveness of the strategic reserve mechanism in these cases compared to the reference case. Moreover, since less reserved plants are needed, the generation costs decrease. Nevertheless, the capacity market still remains more adequacy-effective and more cost-effective, i.e. both indicator differences, even if they are lower in these alternative cases, are still positive. In particular, in the alternative cases 7 and 8 and for the strategic reserve mechanism, the plants always quit the energy market too late (around 21.8 years) compared to the optimal economic lifetime, as in the reference case. Indeed, the capacity addition when the NPV is equal to 0 is still too low to offset shutdowns and the arbitrage between existing capacity and new plants is still suboptimal with the strategic reserve mechanism (the increased revenues from the energy market both impact the profitability of new and existing plants: consequently, the use of new or old plants and the arbitrage between them is not modified compared to the reference case for the strategic reserve mechanism).

Finally, with the alternative case 9, only the performances of the strategic reserve mechanism are modified. In this case, the TSO can contract a larger volume of reserves to avoid shortages. Consequently, the TSO can guarantee a margin closer to the target margin and the adequacy-effectiveness difference is reduced between both CRMs compared to the reference case. However, the increased volume of reserved capacity results in higher O&M costs. It explains why the strategic reserve mechanism is even more expensive than the capacity market compared to the reference case.

7.5.3. Alternative case studying different costs and technical parameters

In the alternative cases 10 and 11, the O&M costs are modified. In particular, the value during the first 10 years (which is considered as constant) is assumed to be equal to $15,000/MW in the alternative case 10 and to $20,000/MW in the alternative case 11. In both cases, the O&M costs at the end of the economic lifetime (which is kept equal to 20 years) are computed so that there are equal to the annualized costs of a new plant (see figure 75). For these both alternative cases, the capacity market continues to always reach the target margin and the average lifetime of plants is equal to about 20 years for the same reasons as previously mentioned. In particular, the higher O&M costs (which increase the missing money since the revenue curve is kept identical as in the reference case) are offset by a higher capacity bid for existing and new plants. An optimal arbitrage is still possible between these plants thanks to their capacity bids. For the strategic reserve mechanism, this modification however changes the investment decisions. Indeed, since O&M costs increase compared to the reference case, market players need higher expected revenues from the energy market to make investment decisions all other thing being equal. Consequently, the average margin on the energy market tends to be lower for the strategic reserve mechanism in the alternative cases 10 and 11 compared to the reference case (the average margin is equal to 2.8% in the alternative case 10 and to 2.3% in the alternative case 11 compared to 3% in the reference case). A lower margin then results in a lower adequacy effectiveness of the strategic reserve mechanism[156].

Regarding generation costs, the difference between both CRMs tend to decrease with the alternative cases 10 and 11. Indeed, as noticed in figure 75, O&M costs after the economic lifetime tend to increase less quickly in the alternative cases than in the reference case. Consequently, the fact of keeping old plants in the strategic reserve mechanism (more

[156] Moreover, since the O&M are higher in the alternative case 10 than in the alternative case 11, the strategic reserve mechanism is less adequacy-effective in the alternative case 11.

than 20 years) results in lower O&M costs in the alternative cases. However, these costs remain higher than those of the capacity market.

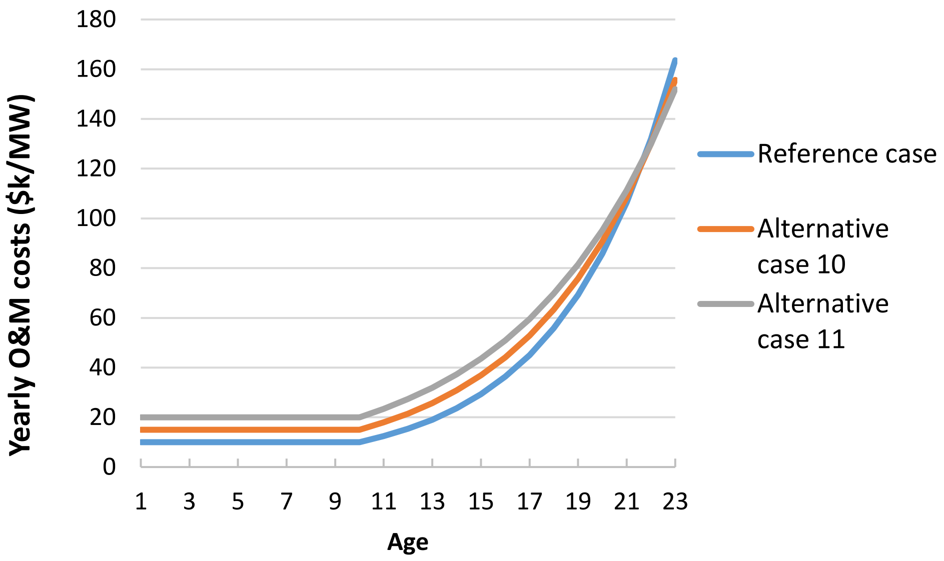

Figure 75: O&M costs considered for the alternative cases 10 and 11

Different lead time for investments are also studied in the alternative cases 12 and 13. The same conclusions as in the reference case can be drawn: the capacity market always appears to be more adequacy-effective and more cost-effective than the strategic reserve mechanism.

7.5.4. Alternative case studying different characteristics of the load

Finally, two different load growth are considered in the alternative cases 14 and 15. They modify the functioning and the results of both CRMs. Nevertheless, the capacity market is still more cost-effective and more adequacy-effective than the strategic reserve mechanism.

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An additional sensitivity study is also investigated by considering the alternative case 1 (which appears as the most beneficial for the performances of the strategic reserve mechanism, in particular regarding its cost effectiveness) as the new reference case. It enables to studying the combined impact of a higher capacity addition and of another parameter (for instance a lower missing money). Results are presented in appendix Q. In all cases, the capacity market appears to be more adequacy-effective and more cost-effective than the strategic reserve mechanism.

To conclude this sensitivity analysis, it appears that the capacity market is always more cost-effective and more adequacy-effective that the strategic reserve mechanism. In particular, performances of the capacity market appear less dependent of the way market players react to expected energy revenues than with the strategic reserve mechanism. This is explained by the ability of the capacity price to stabilize the cyclical tendencies and coordinate investment and shutdown decisions, whatever the conditions on the energy market (for instance a low missing money, a strong herd behaviour). On the contrary, in the strategic reserve mechanism, the energy price is the only tool to coordinate investment and shutdown decisions. The performances of this mechanism then highly depend on the way market players behave and make decisions based on the energy revenues

Conclusions

In this part of this thesis, the long-term issue of investments in generation has been investigated. Indeed, the economic literature on this subject highlights the risk of under investment in current liberalized energy systems due to several market failures that are likely to create a missing revenue for investors. It could result in under capacity and then more shortages than optimal. To solve this adequacy issue, several authors advocate the implementation of new mechanisms, called capacity remuneration mechanisms (CRM), in addition to the traditional energy market. In Europe, the need to resort to these new mechanisms to ensure adequacy becomes a key topic in policy discussions. Several countries have implemented a CRM in the recent years or are studying this possibility. Once the need for a CRM has been decided, it is also necessary to choose the type of CRM. Among the different solutions discussed in literature, current debates in Europe have been focused on two main solutions: the capacity market, as implemented in France, in Great Britain or in Ireland, or the strategic reserve mechanism, implemented in Belgium, Sweden and in Germany. Consequently, a key part of the current debates lies in the comparison of these CRMs from an economic point of view. This comparison is often made from a static point of view, by considering a long-term equilibrium. However, the dynamic aspects of investment decisions are important since cyclical tendencies in generation investments, known as boom and bust cycles, are prone to appear in current energy markets. A long-term equilibrium is then not sure given the characteristics of current markets and market players (herd behaviour, limited information…). As a result, the economic performances of CRMs should also be assessed and compared from a dynamic point of view to study to what extent they can correct the cyclical tendencies and the investment issues prone to happen in energy-only markets.

This part of this thesis aims at assessing and comparing the dynamic effects and economic performances of the capacity market and the strategic reserve mechanism, two of the main CRMs considered in Europe. Their performances should not only consider their adequacy effectiveness, i.e. their ability to reduce shortages to an optimal level and to solve the under capacity issue, but also their cost effectiveness, i.e. the related costs (investment and O&M costs). To answer this research question, a modelling of both CRMs is developed. It uses a System Dynamics approach: it enables to consider the imperfect characteristics of market players which can result in cyclical tendencies. Both CRMs and the energy-only market are then simulated over 30 years for 500 different demand scenarios.

Based on the results, it appears that both CRMs succeed in reducing the cyclical tendencies which appear in the energy-only market, in particular regarding the underinvestment issues. Indeed, with the capacity market, an explicit target is defined. To reach it, in case of expected under capacity, the capacity price increases so that new plants or existing plants break even. With the strategic reserve mechanism, in case of under capacity, the TSO can react by contracting some reserved plants which produce during extra-peak hours to avoid rolling blackouts. However, the strategic reserve mechanism cannot deal with the overinvestment phases since the TSO cannot force market players to close their plants or postpone their investments. On the contrary, in the capacity market, the overcapacity phases never occur. Thanks to the explicit definition of a target, only the cheapest bids receives the capacity remuneration. Then, refused plants become unprofitable and then close (or are not build).

When comparing the economic performances of both CRMs, the capacity market always appears to be more adequacy-effective and more cost-effective for all cases studied. Regarding the adequacy-effectiveness comparison, even if both CRMs succeed in reducing the under capacity phases, the capacity market shows better results. Indeed, the strategic reserve mechanism is sometimes limited by the maximum amount of strategic reserves the TSO can contract to avoid shortages. This limit is often considered in current power systems to avoid disturbing the energy market by producing too often with strategic plants. On the contrary, the capacity market always succeeds in attracting enough plants thanks to the capacity price which creates additional revenues to cover costs.

Regarding the cost-effectiveness performances, the capacity market results in lower generation costs based on the simulations. Two mains reasons explain this. First, overcapacity phases never happen in the capacity market. On the contrary, they may occur with the strategic reserve mechanism: consequently, more plants than needed are online and the associated O&M costs are likely to be higher with the strategic reserve mechanism than with the capacity market for the same peak demand. Second, the higher generation costs of the strategic reserve mechanism are explained by the different arbitrage made between new and existing plants in both CRMs. With the capacity market, a perfect arbitrage is made between bids submitted by these two types of plants. Since O&M costs are modelled as increasing with the age of the power plants, capacity bids of old plants become higher than those of new plants. These new plants are then chosen first by the capacity market (i.e. they receive the capacity price which makes them break even) whereas old and expensive plants are rejected and then closed since they cannot cover their costs. The capacity price and the direct comparison of bids submitted by plants enable to coordinate investment and shutdown decisions and to reach an optimal lifetime of plants. On the contrary, this arbitrage is less efficient in the strategic reserve mechanism since it only relies on the energy price. For instance, if large profits are expected on the energy market, market players tends both to invest and to keep their old plants online. The comparison of costs of new and existing plants is less direct than in the capacity market. Furthermore, even if an arbitrage is possible within the energy market based on the energy price, it does not consider the strategic reserves used by the TSO to avoid shortages. These reserves are necessarily plants which leave the energy market since they become unprofitable. Consequently, the strategic reserves used by the TSO are old and expensive, resulting in high O&M costs.

As a conclusion, it appears that the use of the energy price as the only tool to coordinate investment and shutdown decisions and to reach an optimal level of shortages in the strategic reserve mechanism results in less cost-effective and adequacy-effective outcomes. Indeed, the procurement of strategic reserves is assumed not to modify the energy market and the associated price. On the contrary, with a capacity market, a second market is added in which the TSO defines a capacity target. This explicit definition, and the associated capacity price, helps to coordinate investment and shutdown decisions and to solve the adequacy issue: it explains the better economic performances of the capacity market, regardless of the conditions of the energy market.

The results also highlight the importance of assessing the dynamic aspect of the capacity mechanisms. Due to several particular factors, the achievement of an equilibrium state in power systems regarding the investment issue is not certain and some cyclical tendencies appear in the energy-only market. That is why capacity remuneration mechanisms have to be assessed and compared not only from a static point of view but also with a dynamic aspect. Moreover, from these results and based on the assumptions and data made in these chapters, the capacity market appears to be more robust and beneficial than the strategic reserve mechanisms from the economic point of view, since it decreases shortages at lower costs. These results have direct implications for policy-makers when they decide whether they have to implement a capacity market or a strategic reserve mechanism.

General conclusions

One key objective of market design is to efficiently ensure the reliability of electricity systems, that is to say adequacy in the long term and security in the short term. These two dimensions are essential to maintain a well-functioning power system and then ensure the success of market reforms. This dissertation has aimed at improving the current discussions on market design by giving insights on the best market design to implement to ensure security and adequacy.

In the first part of the thesis, a focus has been made on the short-term dimension of the reliability: the power system security. To ensure it, TSOs rely on reserves, i.e. capacities which are available in real time to be activated upward or downward to solve imbalances. The availability of reserves in real time is ensured thanks to a specific task: the security model. In this thesis, the economic characteristics of two types of security models have been studied and compared: those of the margin approach, which is currently implemented in France and those of the reserves approach, implemented in several European countries such as Germany or the Netherlands. In particular, this first part has quantified what would be the costs or benefits for the French power system, which currently uses a margin approach, to change its security model and implement a reserves approach. To answer this research question, a modelling based on an agent-based approach, and which simulates the decisions of decentralized and profit-based players on several short-terms markets, from reserves procurement to the balancing mechanism, has been developed. This modelling has enabled to represent the complex short-term sequence of markets and mechanisms while considering technical constraints of power plants, the bidding strategy of market players and their likely imbalances due to forecast errors, which all appear essential to study the French security model. The main results have shown that the margin approach always leads to lower production costs than the reserves approach. On average, over the fifteen studied weeks, the difference in production costs is around € 545,000 per week for the simulated French power system. These results are mainly explained by the different distortions of the merit order in each security model. The margin approach limits these distortions to some hours and for a limited volume when activations to ensure system are performed. On the contrary, the reserves approach distorts more frequently the merit order and for a large volume, which imposes the production of more expensive technologies and increases the associated generation costs. Results of the simulations have also enabled to study how both security models can influence market player's decisions, in particular how the reserves approach can send wrong incentives to BRPs to be balanced in real time.

In the second part of this dissertation, a focus has been made on the long-term dimension of the reliability, namely the adequacy. Current designs in Europe built around an energy-only market are subject to several market failures which impede efficient investments decisions in generation. This part has studied and compared two mains solutions debated and implemented in Europe to solve the adequacy issue: the capacity market and the strategic reserve mechanism. Moreover, these two CRMs have been studied from a dynamic point of view given the importance of the cyclical behaviour in investment decisions. Their comparison has been based not only on the adequacy effectiveness (i.e. reaching a right level of installed capacity) but also on the cost effectiveness (i.e. doing so at least costs). To answer the research question, a modelling based on Systems Dynamics has been developed. It has enabled to consider the real and imperfect characteristics of market players (for instance, herd behaviour, limited foresight) and their investment and shutdowns decisions, which can result in cyclical tendencies. This type of modelling has also enabled to compare CRMs considering a realistic and dynamic framework in which a long-term equilibrium may not be reached. First, the results have highlighted the importance of considering the dynamics when assessing performances of CRMs. Due to several factors, the achievement of an equilibrium state in power systems regarding the investment issue is not certain and some cyclical tendencies appear in the energy-only market. That is why CRMs have to be assessed and compared not only from a static point of view but also with a dynamic aspect. Moreover, this part has given insights on the best CRM to implement. Based on the results, the capacity market appears to be more goal- and cost-effective, i.e. it succeeds in achieving a right level of installed capacity and at lower costs than the strategic reserve mechanism. These results are mainly explained by the second feedback loop that the capacity market creates. Indeed, with an energy-only market or with the strategic reserve mechanism, the energy price is the only tool to coordinate investment and shutdown decisions and to reach an optimal level of installed capacity. Due to several market failures and some characteristics of market players' behaviour, this energy price does not succeed in attracting enough investments and in coordinating shutdown and investment decisions. With a capacity market, a second feedback loop is added: a new market is implemented to ensure a sufficient level of capacity. The resulting capacity price helps to coordinate investment and shutdown decisions and to reach the target level of capacity defined by the TSO. It explains the better economic performances of the capacity market, regardless of the conditions of the energy market.

Based on these two research questions and their associated modelling and results, this dissertation brings valuable insights from an academic and policy point of view. From the academic side, these works contribute to the modelling of real markets and power systems and to the methodological aspects to compare different market designs. They bring insights on the detailed functioning of different security models, in particular of the French approach. They also highlight several characteristics of markets or market players which have to be considered when assessing performances of market design, in particular the importance of technical constraints for the outcomes of short-term markets, the way market players integrate them in their pricing strategy, the dynamics of investment decisions or the endogenous consideration of shutdown decisions. Moreover, the importance of the TSO and the impacts its tasks can have on the markets outcomes, for instance through the reserves procurement, the activations to ensure system margin or the creation of a CRM, are also underlined with the results. The modelling developed in both parts also contributes to the existing academic literature by filling some missing points, such as the modelling of the strategic reserve from a dynamic point of view, the endogenous consideration of shutdown decisions, the modelling of security models and in particular of the French margin approach or the study of the way a power exchange can be modelled when non-convex technical constraints are considered. Finally, both developed models provide a relevant framework for future researches on short-term and long-term dynamics and constitute a basis for further studies.

From a policy perspective, the results of this dissertation give insights to policy makers regarding market designs to implement. According to the case studied in this thesis, it appears that the current security model in France should be preserved since it is cheaper than the reserves approach. These results are particularly useful in the context of the European discussions concerning setting and implementation of network codes, whose main goal is to harmonize market designs in Europe. The level and benefit of harmonization should be balanced with the potential (national) cost of implementing new design (for instance if the French TSO must change its security model to harmonize with foreign countries). Moreover, regarding the adequacy issue, the solution of a capacity market appears more interesting than the strategic reserve mechanism. In particular, the results contribute to the European discussions on the evolution of market designs in the context of the Clean Energy Package (Winter Package) of the European Commission, which authorizes the implementation of CRMs in Europe under different rules. CRMs have to be assessed according to the State aid guidelines. Then, when implementing a precise type of CRM, its ability to solve the adequacy issue and the associated costs should be studied to justify economically its implementation compared to other solutions. The results of this thesis give insights on this assessment.

Future research

First, further work should study different and more extreme scenarios to broaden the conclusions and their significance. For instance, in the study of security models, an in-depth study of input parameters was performed to reduce the uncertainties of the results (which would happen if input parameters were chosen in a more simplified way). However, it would be interesting to compare both security models for different levels of the additional required reserves in the alternative security model and to assess when the security in the alternative security model would become at stake (for instance, the two models could be compared using prospective scenarios with high level of intermittent renewable energy penetration). Moreover, the studied weeks were simulated over average and representative weeks. Peculiar situations were overlooked since their occurrence are very low and would have required simulating a large number of weeks to consider them properly. However, it can be interesting to compare both security models for these more constrained situations, for instance when large imbalances happen (e.g. due to an outage of a power plant) or when the demand is high compared to the available capacity (which can result in rolling blackouts). This consideration would require a more precise modelling of the power system and how market players and the TSO react in this case. Moreover, a trade off with the computation time would be necessary. Regarding the study of CRMs, scenarios with different levels of missing money could be investigated. Moreover, scenarios with constant or decreasing load, as it is the case in some European countries due to the development of decentralized production, could also be studied: with these scenarios, the need of investments may be lower and performances of CRMs can then differ.

Second, the modelling of the behaviour of market players could also be improved. For the study of the security models, it would be interesting to incorporate a learning process in the behaviour of market players. Indeed, they could learn from previous wrong forecasts and previous market outcomes and then improve their next decisions, in particular regarding the day-ahead price forecast. It would also be interesting to study how market players can react to imbalance settlement prices, in particular when activations to ensure system margin are made, to assess whether they send right incentives to help balancing the system. Regarding the long-term study, a relevant further study of the decisions made by market players should consider the mothballing decisions, which become more and more important in current power markets. These decisions can avoid decommissioning definitely a power plant and should then be considered when comparing both CRMS. Since mothballing may help reducing capacity cycles (Arango et al., 2013), performances of the energy market and of both CRMs may differ considering this possibility (Ousman Abani et al., 2017). The risk aversion of market players can also be considered to study their impact of the investment decisions and the performances of CRMs (Ousman Abani et al., 2018).

Third, in a context where European energy markets are more and more integrated, the question of having different types of security models or different CRMs in Europe could be raised. In particular, the benefit of maintaining the margin approach in France could be compared with the costs of non-harmonization of security models in Europe. Similarly, the costs associated with the existence of different types of CRMs in Europe and their interaction could be investigated.

Finally, the long-term modelling could be improved by considering a more detailed short-term energy market. Indeed, to simplify, an exogenous curve was used here to compute revenues from the energy market depending on the system margin. A major improvement would be to model short-term market decisions and the way market players bid into the energy market to compute more precisely the short-term profit when making investment decisions. In particular, given the current discussions about flexibility in Europe, it would be relevant to study how the short-term flexibly constraints (for instance, the fact of starting more frequently conventional power plants to cover the intermittency of wind and photovoltaic production) are translated into short-term energy prices and subsequently into investors' reaction. In a well-designed system with high intermittent energy penetration and a flexibility need, investments which add flexibility would be stimulated by price signals compared to less dynamic units. For instance, in case of negative prices, which reflect a lack of flexibility in the system, a storage facility would earn money, sending then incentives to invest in this technology. Such optimal investments will help the system to reach a long-term situation where costs to accommodate high intermittent injections are minimized. Consequently, it would be interesting to assess whether the current market designs (and in particular the short-term electricity prices) send the right incentives to invest in flexible technologies when needed. Studying the interaction between flexibility needs in the short-term markets and investment decisions would require combining both a detailed modelling of short-term markets (which accounts for power plants' technical constraints, in particular the non-convex technical ones, as it was done in the first part of this thesis) and a modelling of investment dynamics considering market players' behaviour (as it was done in the last part of this thesis).

Appendix A. The specific modelling of the day-ahead market when considering non-convex technical constraints[157]

Once the general approach of an agent-based model has been chosen for the entire modelling, the modelling of the precise day-ahead market should be investigated. Indeed, this market is essential for power systems as it provides a reference price for energy and greatly influences decisions made by market players regarding the generation schedule of their plants (for instance, the production level or the start-up or shutdown decisions). A particular attention should be paid to this modelling when technical constraints, and in particular non-convex technical constraints (such as the start-up costs or the minimum output) are considered. The modelling of the bidding strategy of market players on the day-ahead market and the resolution of this market considering these constraints are important since they influence the generation schedule of power plants, imbalances of market players and then the margin study.

In particular, two different organizations of day-ahead market, and two related modelling choice, can be distinguished in current power systems: the power-exchange (PX) and the centralized power pool (Meeus and Belmans, 2007). In the case of PXs, like in many European markets, market players submit bids to sell or buy electricity. Initially these bids consisted of one or several price-quantity pairs for each hour, known as simple bids. New advanced bidding products, known as complex bids (e.g. blocks bids, linked bids, etc. (EPEX SPOT et al., 2016)), were introduced and enable players to better incorporate their non-convex costs and constraints but implicitly (for instance they cannot express explicitly their start-up costs) and then in an imperfectly way. The electricity price is computed by matching offer and demand while respecting the different constraints expressed in the bids. Conversely, in a centralized power pool organization, like in the US markets, market players submit multi-part bids reflecting explicitly their costs (variable and start-up costs) but also their technical constraints (Sioshansi et al., 2008). Then, a central player computes the optimal production schedule which minimizes the total costs of the system and which meets the demand while taking into account the technical constraints. The price is defined as the shadow costs of the balance constraint

157 Main results mentioned in this appendix have been presented during the 2016 13th International Conference on the European Energy Market. The associated paper "Review of models for power exchanges with non-convex technical constraints for investment decisions" has been written with Marcelo Saguan and Vincent Rious.

and has often to be completed with a side-payment to ensure cost-recovery (O'Neill et al., 2005). Thus, these two main organizations are often represented thanks to two different models. PXs are generally modelled in a decentralized manner (David and Wen, 2000); market players have the objective to maximize their revenues by submitting the most optimal bids reflecting their costs and their constraints, eventually considering their competitors' strategies. Conversely, power pools are often modelled with a centralized UCM which considers explicitly technical constraints submitted by plants and all their costs (Van den Bergh et al., 2014). Within this part of the thesis, a PX organization is chosen as it is the current situation in France with EPEX SPOT.

Even if these two organizations and their related models seem to be different, they lead to the same results regarding the commitment decisions and the electricity price under certain assumptions (e.g. perfect information) and when non-convexity can be overlooked (Caramanis, 1982). As a result, the functioning of a PX can be studied thanks to a UCM, which is easier to implement: a simple merit-order is often performed based on the marginal costs of the different plants and the energy price is defined by the last accepted bid. However, when non-convexity are significant (e.g. due to start-up costs and the need for frequent start-up of generators), this equivalence can be challenged and the choice of a UCM to model the functioning of a PX can be questioned.

The main question is then to assess how the bidding strategy of market players should be modelled in presence of a PX and when considering non-convex technical constraints. Two main solutions can be distinguished:

- Either market players submit multi-parts bids reflecting all their costs (marginal and start-up costs) and all their technical constraints; the day-ahead market is solved thanks to a UCM, as for power pool organization. Theoretically, this solution is relevant when non-convex constraints are ignored.
- Or market players submit simple or complex bids in which they try to express implicitly all their costs and their constraints: a bidding strategy should then be defined to study how these bids have to be formulated to maximize profits while avoiding that the accepted bids cannot be technically feasible. The day-ahead market is then computed by performing the clearing of demand and bids formulated by

market players (for instance, defined as the intersection of the supply and demand curve).

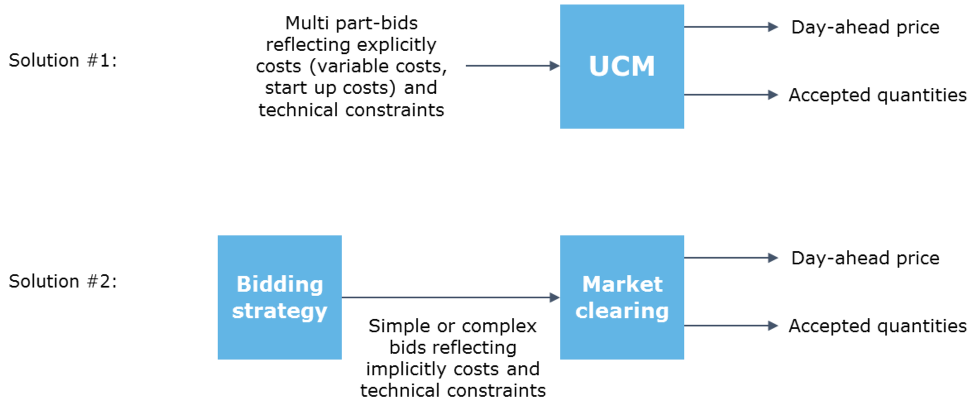

Figure 76: Solutions to model a PX when considering non-convex technical constraints

These two solutions are represented in simplified way on figure 76. To the knowledge of the author, such a comparison in the context of a PX is missing in the literature. A qualitative comparison of advantages and drawbacks of the aforementioned approaches to model the short-term PX-based market is then performed[158]. Four different models to represent a PX (when technical constraints are considered) are investigated:

1) A centralized UCM (in theory, this model can correctly model a PX when non-convexity and imperfect information are disregarded).

2) A convex UCM where a centralized UCM is simplified to remove non-convexity

3) A decentralized model: it models the functioning of a PX by computing the supply and demand curves formulated by the market players. Two versions of this model are studied:

    a. With simple bids only (market players can only formulate simple bids)

    b. With simple and complex bids (according to their constraints and their own optimization, players can also formulate different types of complex bids)

[158] In particular, within this modelling, it is not possible to model the different solutions and to compare them quantitatively due to time constraints. A simplified qualitative comparison is then carried out.

These four models are assessed according to two criteria:

1) Since the idea is to have a realistic representation of players and their bidding strategy in a PX taking into account non-convex technical constraints, the first criterion should evaluate the achievement of this goal: <u>Criterion 1</u> - Is the model relevant for modelling a PX-based market like in most European countries? It will be assessed according to three points:

    a. Are the technical constraints considered as the market players do (or can do) in a European market with a PX?

    b. Is the computed price relevant regarding the possible prices experienced in a European market with a PX?

    c. Does the model enable to consider the characteristics of market players' behaviour (for instance, limited information, strategic behaviour…)?

2) Since a greater realism generally means models more complex and difficult to run, this point should also be assessed to ensure the computational tractability of the model: <u>Criterion 2</u> - Is the model complex to implement and run? This point is particularly relevant when non-convexities are considered. Indeed, they can make the problem difficult to solve, resulting in a burdensome computation time or even the possibility of not finding a feasible solution. In that case, it is challenging to formulate the problem in a more computational friendly way without allowing considerable simplifications. This complexity criterion will be studied based on:

    a. The complexity of the problem formulation

    b. The computation time

    c. The existing experience feedbacks

    d. The complexity of the price computation

In the following parts, each model will be described and then evaluated according to the previously mentioned criteria. These assessments are mainly based on a critical literature review and are qualitative (the interest being to assess these models ex-ante without building them to then select the most relevant one).

A.1 Centralized UCM

A.1.1. Description of the model

A centralized UCM consists in the minimization of the total costs for the system (variable costs but also start-up costs or shortage costs) under several constraints, among them the power balance equality constraint and the technical constraints explicitly defined by the producers. Thus, the technical characteristics defined by the producers are explicitly considered. As a result, the UCM computes the optimal commitment and dispatch for each unit and for each time step, provided that the inputs expressed by producers reflect the real costs and constraints.

When the problem is non-convex, a struggling issue of UCM lies in the definition of the energy price. If it is defined as the shadow cost of the balance constraint, it may not support a competitive equilibrium (Scarf, 1994). Indeed, since non-convexity costs cannot be reflected into a linear price, producers can incur a loss (e.g. in case of start-up) and then have incentives to deviate from the UCM optimal solution if price is built that way. Different solutions which all reside in the same overall idea of giving side-payment to producers have been proposed and implemented, notably in US markets (e.g. the make whole payment, the convex hull pricing) (Gribik et al., 2007; O'Neill et al., 2005). This payment aims at offsetting the total costs for producers and then avoiding any deviations from the optimal scheduling.

A.1.2. Assessment of the model

A.1.2.1. Criterion 1

The UCM does not seem very well designed to model the functioning of a PX considering technical characteristics. With the introduction of non-convexity, the equivalence between PX and power pool can be challenged. In particular, in a UCM, producers can easily express their different costs and constraints thanks to multi-part bids. Thus, by considering explicitly these non-convex constraints, the UCM results in a technical feasible output at minimized costs. In a PX, these characteristics are considered implicitly: market players translate their constraints and costs in complex bids in a competitive market. As a consequence, imperfect information can significantly impact the bids made by the players. For instance, if a producer wants to recover the start-up costs, it may need to know the number of hours its plant will be committed to spread over these costs on these hours (and not only on the first one). Different guesses on this number will result in different bids. Then, it can lead to a suboptimal dispatch because technical constraints are not optimally reflected in bids (e.g. the producer can underestimate the number of hours its plant will be on, leading to an overestimation of its bid which then increases the probability of being rejected by the market clearing process). UCM, by construction, cannot consider this non-optimality and always results in feasible solutions from a technical point of view. Then, a UCM and a PX-based market are likely to result in different generation decisions.

Regarding the relevance of the price, a UCM also seems far from what is observed in PXs. Indeed, there is not a unique way to define the price with the UCM and the introduction of a side-payment does not represent the price in PXs. Indeed, most of existing side-payment are discriminatory (i.e. the payment is different for each producer, based on its profits) and nonlinear (with the generated energy) (Herrero et al., 2015). On the contrary, in PXs, a non-discriminatory and linear price is used.

Finally, a UCM, like all optimization methods, is not well designed to consider precisely the characteristics of market players (as different access to information and strategic behaviours) since this method is centralized and leaves little room to consider the players' characteristics.

A.1.2.2. Criterion 2

The formulation of the problem is quite easy and the associated literature well documented. The different technical characteristics can be translated into constraints for the optimization quite easily as they are considered explicitly (mainly thanks to binary variables). Regarding the computation time, recent improvement of solver performances (in particular for MILP models) reduces it considerably. Moreover, this time can be further reduced with limited impacts on the results thanks to several simplifications (for instance, a clustered unit commitment (Palmintier and Webster, 2011) or a reduction of temporal resolution (Kirschen et al., 2011). Finally, regarding the complexity of price computation, as mentioned previously, there is not a unique way to compute it and some can be quite complex to model (Huppmann and Siddiqui, 2018), in particular if the computed price has to show some similarities with price experienced in PXs.

Table 15 sums up the qualitative assessments of the centralized UCM to study short-term markets organized around a PX when technical constraints are considered with regards to their relevance to model a PX and their modelling complexity.

Table 15: Qualitative assessment of using a centralized UCM

+ : good ; 0 : medium ; - : weak	***Centralized UCM***
Criterion 1: Is the model relevant for a European market with a PX?	
Consideration of technical constraints as the market players do (or can do) in European markets with a PX	-
Relevance of computed prices regarding the possible prices experienced in European markets with a PX	-
Consideration of the characteristics of market players' behaviour	-
Criterion 2: Is the model complex to implement?	
Computation time	**0**
Complexity of the problem formulation	+
Existing experience feedbacks	+
Complexity of the price computation	-

A.2 Convex centralized UCM

A.2.1. Description of the model

One of the main drawbacks of the centralized UCM lies in the non-convexity of the problem and the impossibility to easily define linear prices which support a competitive equilibrium. To overcome this limit, it is possible to transform the previous UCM into a convex problem (Müsgens and Neuhoff, 2006). In this model, the binary variables considered to model commitment of power plants are replaced by continuous variables. Thus, there is no minimum output constraint and a plant can start up between any values from zero to its maximum output. Additionally, start-up costs are now considered as linear. However, some constraints which require binary variables cannot be kept in this convex model or need to be simplified (e.g. the minimum up and down time constraints). Thus, these simplifications can lead to non-optimal considerations of the technical constraints and to infeasible generation decisions. However, Abrell et al. (2008) showed that if the parameters of the simplified UCM (i.e. variables costs, ramping restrictions…) are calibrated carefully (using an MPEC whose upper level aims at minimizing the deviations between the non-convex UCM and the convex UCM results), total costs and generation results can be quite similar to the results of the non-convex UCM. Finally, this model being convex, electricity price can be computed straightforwardly as the shadow cost of the balance constraint and it supports a competitive equilibrium (considering the different assumptions made in this model).

A.2.2. Assessment of the model

A.2.2.1. Criterion 1

As for the UCM, the binary-relaxed UCM is not well designed to consider technical constraints in the same way than market players do in PXs since they are considered explicitly within this model (and not implicitly through complex bids depending on the producers 'expectations). Moreover, the simplifications made in this model may worsen this point as some technical constraints may not be considered (e.g. the start-up duration time) or may be considered in a simplified way (for instance, the start-up costs). For instance, based on this model, a plant can start-up instantly. In a system with PX, a producer is more likely to consider (possibly in an imperfect way) this duration by formulating bids whose offered quantity increases with time to reflect the start-up procedure.

Regarding the energy price, the model seems more relevant for PXs than the first model. Indeed, here, the price is unambiguous and defined as a shadow cost. Moreover, it can reflect some flexibility constraints as there are observed nowadays in PX. For instance, prices can be above the variable costs during peak demand hours to reflect the start-up costs (Abrell et al., 2008). Still, due to the simplified nature of the problem (in particular the simplification of start-up costs), the relevance of the prices is limited.

Finally, it is difficult to consider the characteristics of market players in this model since it remains a centralized model that does not model the behaviour of market players and their bid building process.

A.2.2.2. Criterion 2

As for the UCM, the problem may be quite easy to formulate as an optimization if most constraints requiring binary variables are removed. However, if these constraints have to be considered (to have a more accurate model), the problem can become complex (or maybe impossible) to formulate. Moreover, only few references and feedbacks are available in the literature regarding the application and the relevance of this model. Since binary variables have been removed, computation time should be well reduced compared to the classic UCM. However, it should be noted that this time could be drastically increased if an additional step is added to calibrate carefully the parameters to obtain the closest possible solution from the UCM (e.g. thanks to an MPEC). Finally, as mentioned previously, the price is easy to compute based on the shadow cost of the balance equation.Table 16 sums up the qualitative assessments of the convex UCM with regards to the two criteria.

Table 16 : Qualitative assessment of using a convex UCM

+ : good ; 0 : medium ; - : weak	***Convex UCM***
Criterion 1: Is the model relevant for a European market with a PX?	
Consideration of technical constraints as the market players do (or can do) in European markets with a PX	-
Relevance of computed prices regarding the possible prices experienced in European markets with a PX	**0**
Consideration of the characteristics of market players' behaviour	-
Criterion 2: Is the model complex to implement?	
Computation time	+
Complexity of the problem formulation	**0**/+
Existing experience feedbacks	**0**
Complexity of the price computation	+

A.3 Decentralized model

A.3.1. Description of the model

The aim of this model is to represent the strategies of market players in a liberalized market with a PX, in which they cannot express explicitly their constraints and their non-convex costs. Each producer faces a profit maximization objective (computed based on expected prices and its costs) and has to produce within its feasible technical range. Thus, producers develop a bidding strategy to reach these goals. In the most simplified strategy, they would bid their marginal cost. However, with non-convex constraints and costs, the bidding strategy should be improved. For instance, players can forecast future prices, perform a price-based self UCM to assess how their plants would produce and then modify their bids to reflect not only marginal costs but also the possible start-up costs (or the avoided start-up costs) (Maenhoudt and Deconinck, 2014; Sensfuß, 2007; Xu and Christie, 2002). Similarly, they can modify their bids if they expect to be dispatched in an infeasible zone. For instance, if they expect that during one hour only the forecast price will be above their marginal costs, they shall formulate a high offer to avoid being dispatched and then starting their plant for only one hour. Moreover, in current PXs, producers can also use complex bids (e.g. linked bids, blocks bids) to express more precisely their constraints. For instance, with linked bids, a child bid is only accepted if the parent bid is accepted: it enables to express the start-up technical constraints, the start-up costs being reflecting in the parent bid and then the fuel costs only in the child bid. A block bid can also be formulated: the bid can only be accepted for its full quantity and for several hours (defined by the producer) or not at all. This kind of bid may reflect the minimum output constraint of power plants (a plant cannot produce between 0 and its minimum output) or the minimum up time constraint (to start up a plant, a producer wants to be sure it will produce during a certain number of hours). Thus, producers face a complex problem, having to choose between different products (simple bids, linked bids, blocks bids…) depending on their forecasts and their costs. Moreover, in case they opt for a complex bid, they have to decide on its characteristics (price, quantity but also number of hours in case of a block bids, links between bids in case of linked bid). This strategy also highly depends on the players' behaviour. Indeed, they have to perform their own price forecast and take into account their rivals' actions. The risk aversion or the competitive behaviour of producers can also impact the way bids are built. For instance, a risk-averse producer may prefer using a block bid to be certain to start up its plant for a certain number of hours and then cover its start-up costs – e.g. for 10 hours. However, by doing so, the probability that the market rejects the bid increases since the constraints of the bids are more stringent. A less risk-averse market player may want to formulate a shorter block bid – e.g. 5 hours - then increasing the probability that the costs are not covered by prices but decreasing the probability of being rejected. Considering all these additional parameters add complexity to the model.

Once bids have been formulated by all the players, the energy price can be computed as the intersection of supply and demand curves. In the case of complex bids, this price is more difficult to compute as non-convex constraints are added in the clearing of the market (e.g. constraints related to block bids or linked bids) (Meeus et al., 2009). Market equilibrium with strict linear prices and non-convex bids (which is the case of complex bids mentioned previously) is a mathematical impossibility (Madani et al., 2016) and even finding the best solution is often impossible given the time constraints for the clearing (Meeus, 2006). Several formulations of algorithms to define the clearing prices with non-convex bids have been proposed in the literature (Madani and Vyve, 2014; Martin et al., 2014). A new difficulty then appears to define the price with this kind of model when non-convex bids are considered.

Furthermore, the resulting generation decisions are not necessarily feasible from a technical point of view (since technical constraints are not expressed explicitly). Then, producers have to reschedule their plants once they know the result of the market clearing and their accepted bids to avoid costly imbalances. Most of the time, they solve these imbalances by offering or asking for energy in the intraday market.

In the literature, the most convenient way to study this bidding strategy is an agent-based model, in which each agent is modelled and performs its own optimization. This model can consider some difficult real-world aspects such as asymmetric information, strategic interaction, collective learning, and the possibility of multiple equilibria (Weidlich and Veit, 2008). It also enables to study how players learn and react from past market outcomes. One can distinguish between two types of decentralized models to represent a PX, one where only simple bids are possible and one where players can use simple and complex bids. Their assessment with regards to their relevance to model a PX and their modelling complexity (criteria 1 and 2) is presented below.

A.3.2. Assessment of the model with simple bids only

A.3.2.1. Criterion 1

By construction, this model is relevant to model PXs. Indeed, the model tries to mimic the way producers construct their bids trying to maximize their profits and respecting their technical constraints with imperfect forecasts on day-ahead PX prices. Moreover, by reflecting their technical constraints and costs into their bids (for instance, by adding the start-up costs to the variable costs), the final computed energy price can reflect some of these constraints. However, in this version, by limiting bids to simple bids, the technical constraints are not considered as exactly as market players can do in Europe in PXs (technical constraints can only be translated into simple bids, which is a great limit compared to what complex bids enable). In any case, the dispatch outcomes of this model are more likely to be relevant regarding what is experienced nowadays in PXs, especially compared to the UCM previously considered. Finally, the consideration of players' characteristics (e.g. limited information) is one of the main strengths of agent-based models.

A.3.2.2. Criterion 2

The better relevance of this model (compared to both UCMs) comes with an increased complexity to formulate and run it. Indeed, there is not a unique way to formulate the problem (as it can be the case with a UCM) and formulations depend on many characteristics and assumptions (e.g. competition, available information for producers). Moreover, profit maximization made by producers highly depends on the forecast they made on the future price. Thus, the model should incorporate a price forecasting tool which can be really complex (depending on the required level of accuracy) (Weron, 2014). Furthermore, some technical constraints cannot be considered straightforwardly with simple bids and then can require advanced simplifications or formulations (e.g. minimum output level). Finally, it can be necessary to model an additional market (e.g. intraday or balancing market) to enable players to solve their possible technical infeasibilities. Thus, all these features add complexity to the model formulation.

Moreover, few papers study this model in the literature with consideration of technical constraints. They mainly assess the way producers reflect start-up costs (or avoided start-up costs) in their simple bids (Sensfuß, 2007). Other more complex constraints are often disregarded or poorly considered. This problem also requires some computation time as an optimization is necessary for each player for each time step to compute its optimal bids. However, since only simple bids are considered, the computation remains limited. Finally, the price can be computed easily as the intersection between the supply and demand curves (since all bids are simple bids).

Table 17 sums up the qualitative assessments of the decentralized model with simple bids only regarding both criteria.

Table 17 : Qualitative assessment of using a decentralized model with simple bids only

+ : good ; 0 : medium ; - : weak	***Decentralized model with simple bids only***
Criterion 1: Is the model relevant for a European market with a PX?	
Consideration of technical constraints as the market players do (or can do) in European markets with a PX	**0**
Relevance of computed prices regarding the possible prices experienced in European markets with a PX	**0**
Consideration of the characteristics of market players' behaviour	+
Criterion 2: Is the model complex to implement?	
Computation time	**0**
Complexity of the problem formulation	**0**
Existing experience feedbacks	**0**
Complexity of the price computation	+

A.3.3. Assessment of the model with simple and complex bids

A.3.3.1. Criterion 1

The main limitation of the previous model (i.e. the absence of complex bids) is solved in the new model: producers can reflect most of their technical constraints into complex bids, depending on their own optimization. Thus, it is perfectly relevant when studying current PXs, in which complex bidding have been recently introduced to enable producers (and in particular thermal producers) to better express their technical constraints and their costs above the variable costs. Similarly to the previous model, players' characteristics can be perfectly considered with this model.

A.3.3.2. Criterion 2

As for the previous model with simple bids, the better relevance of the model comes with an increased complexity. The problem formulation is even more complicated with the introduction of complex bids. Indeed, producers should optimize their bidding strategy considering several different solutions (simple bids, blocks bids, linked bids…). Thus, they have to decide first on the optimal product to bid and then on the characteristics on this bid. Similarly, the computation time can be substantial (mainly because the strategic bidding of each player will be complex and long to solve). Moreover, to the knowledge of the authors, there is no available literature studying decentralized bidding with complex bids. Finally, with complex bids, the price is no longer computed as the intersection of demand and supply curves (because of the non-convexity of the complex bids). Instead, it results from an optimization with several constraints which makes the problem even more complex and long to solve (Martin et al., 2014).

Table 18 sums up the qualitative assessments of the decentralized model with simple and complex bids regarding both criteria.

Table 18: Qualitative assessment of using a decentralized model with complex bids

+ : good ; 0 : medium ; - : weak	***Decentralized model with complex bids***
Criterion 1: Is the model relevant for a European market with a PX?	
Consideration of technical constraints as the market players do (or can do) in European markets with a PX	+
Relevance of computed prices regarding the possible prices experienced in European markets with a PX	+
Consideration of the characteristics of market players' behaviour	+
Criterion 2: Is the model complex to implement?	
Computation time	-
Complexity of the problem formulation	-
Existing experience feedbacks	-
Complexity of the price computation	-

A.4 Conclusion

Table 19 sums up the assessments of the four main models to study short-term markets organized around a PX when technical constraints are considered.

Table 19: Qualitative assessment of four different approaches to study short-term markets organized around a PX when technical constraints are considered

+ : good ; 0 : medium ; - : weak	*Centralized UCM*	*Convex UCM*	*Decentralized model with simple bids only*	*Decentralized model with complex bids*
Criterion 1: Is the model relevant for a European market with a PX?				
Consideration of technical constraints as the market players do (or can do) in European markets with a PX	-	-	**0**	+
Relevance of computed prices regarding the possible prices experienced in European markets with a PX	-	**0**	**0**	+
Consideration of the characteristics of market players' behaviour	-	-	+	+
Criterion 2: Is the model complex to implement?				
Computation time	**0**	+	**0**	-
Complexity of the problem formulation	+	**0**/+	**0**	-
Existing experience feedbacks	+	**0**	**0**	-
Complexity of the price computation	-	+	+	-

A trade-off between the relevance of the model for the European PXs and the complexity to implement the model is needed. Considering a centralized UCM could lead to high differences since non-convex technical constraints are considered explicitly and then the accepted bids of this market are always technically feasible (in particular, market players cannot be imbalanced because they sell a quantity of energy different from what they can actually produce). Moreover, the defined price is far from the observed price in PX in Europe: for instance, the existence of a side payment is not relevant for the modelling of the French system and can modify market players' decisions on other markets (for instance, in the reserve procurement market). As a result, the equivalence that can be assumed when non-convex constraints were not considered seems less relevant for a proper modelling of security models. Moreover, the decentralized model with complex bids is likely to be more realistic but very difficult to implement. Since the study of both security models already requires the modelling of five markets or mechanisms, the complexity and the computation time of the sole day-ahead market should remain limited. Thus, a decentralized model with simple bids seems to be a wiser solution. It enables to have a limited complexity but high enough to formulate a bidding strategy which can consider implicitly non-convex technical constraints. This solution is then chosen for the modelling of the French power exchange. A bidding strategy will be defined considering price forecast and technical constraints of power plants. Market players submit simple bids which will maximize their revenues given their incertitude of the future price forecast and while trying to express the technical constraints of their plants (in particular their start-up costs).

Appendix B. Bidding strategy on the day-ahead market for thermal plants

This bidding strategy is inspired by Maenhoudt and Deconinck (2014). It enables to consider technical constraints of the plants but in a simplified and imperfect way because of the limitation to the simple bids, as well as to reflect the possible start-up costs. Moreover, different expected day-ahead price scenarios are considered to reflect the associated uncertainties faced by BRPs when submitting their offers. Two steps are distinguished in this strategy and described below.

B.1 Step 1: Study of the optimal production for each thermal plant, for each hour and for each expected day-ahead price scenario

The first step consists in studying the optimal production of each plant for each hour of the next day and for each expected day-ahead price scenario. For this, a UCM is performed for each estimated price scenario. Each BRP will seek to maximize the profit of its portfolio while considering this BRP as a price taker. Moreover, power plants which are planned to provide reserves are identified thanks to the previous procurement stages: then, it is an input parameter in this optimization, and not a variable anymore. In addition, the optimization problem is solved for each price scenario separately: it enables to better reflect price uncertainty since generation decisions will be different depending on the price scenarios. Finally, this UCM is only carried out for thermal power plants (the bidding strategy for hydroelectric power plants is studied separately). The considered UCM is thus the following one:

$$Max\ Profit = \sum_{\substack{Thermal\ plants \\ of\ the\ BRP}} \sum_{2\ days} [Q_{th} * \widehat{P_{DA}} - C(Q_{th})]$$

$Under\ the\ technical\ constraints\ of\ thermal\ power\ plants$

$Under\ the\ technical\ constraints\ of\ plants\ identified\ to\ provide\ reserves$
$(plants\ identified\ to\ provide\ reserves = parameters\ of\ the\ UCM)$

$With$: Q_{th} $the\ optimal\ production\ of\ the\ thermal\ plant$

$\widehat{P_{DA}}$ $the\ estimated\ day - ahead\ price$

$C\big(Q_{th}(h)\big)$ $the\ production\ costs\ of\ the\ thermal\ plant\ (variable\ cost + startup\ costs\ if\ any)$

Thus, for each price scenario, the BRP computes the optimal generation of its plants for each hour, notably the decisions to start them up or shut them down. Moreover, since day-ahead price scenarios are considered and built in an increasing order, i.e. the price of scenario 2 is necessarily greater than or equal to the price of scenario 1 for each hour (cf. appendix K), the optimal production in the scenario 2 will necessarily be greater than or equal to the optimal production in the scenario 1 for each hour (the optimization constraints are the same, only the valuation of the production changes; thus, the higher the price, the higher the optimal production). This observation is important for the construction of the supply bids made in the second step.

B.2 Step 2: Construction of the supply curve for each hour and each plant based on the previous optimal generation results

The bidding strategy aims at achieving two objectives (Maenhoudt and Deconinck, 2014):

- Reducing the risks that the bid is not accepted by the market when the plant wants to produce (and on the contrary the risk to be accepted when the plant does not want to produce)
    - For example, if the plant wants to produce, it should submit a bid at a price lower than the expected day-ahead price
- Incorporating start-up costs in the bids when possible
    - Power plants will then try to increase their bids beyond their variable cost

In the following section, these two objectives are applied to build the quantities submitted for each plant, as well as the associated prices.

<u>Which quantity to offer per plant and per hour?</u>

The submitted quantities are computed from the optimal generation level determined thanks to the UCM for each day-ahead price scenario and each hour. This construction is performed starting with the lowest forecast price scenario. This corresponds to the minimum volume the plant is willing to produce (this volume may be zero). Therefore, the first submitted quantity is equal to the optimal production of the first scenario.

The BRP then considers the optimal production for the second price scenario. This production is necessarily greater than or equal to the production of the first scenario. If this production is the same (i.e. even with a higher price, the plant does not want / cannot produce more), the plant does not need to submit a second bid. On the contrary (for a higher estimated price, the plant wants to produce more), the plant offers an additional bid whose volume is equal to the difference between the optimal productions in both scenarios. This process is then repeated for all price scenarios: as a result, there is at most one bid per price scenario.

<u>At what price?</u>

The BRP has to determine the price for each of the previous submitted quantity. The general principle is to maximize the probability of being accepted by the market when the plant wants to produce, while reflecting part of the start-up costs in the bids price. Thus, according to Maenhoudt and Deconinck, this price has to respect the following criteria:

- It always has to be lower than or equal to the estimated day-ahead price scenario. Otherwise the BRP anticipates that the bid will be rejected by the market.
    - In particular, if this estimated price is lower than the plant's variable cost, the submitted price should not be made at this variable cost (this situation is possible due to technical constraints. For example, a plant may prefer to lose money for a few hours when the estimated day-ahead price is very low instead of being shut down)
- Whenever it is possible, the plant submits a price above its variable cost to integrate any start-up costs it may bear[159], i.e. a mark-up is added to the variable cost of the plant.
    - Start-up costs are spread over the day for which bids are studied: for example, if a plant wants to start up, the associated start-up costs are spread over the whole day and not only during the hour when start-up decision is made to avoid a too high mark-up on a single hour which increases the probability that this bid is rejected.

[159] Losses made when a plant produces while the estimated day-ahead price is lower than its variable cost are also included in the mark up.

- In addition, the mark-up is assumed proportional to the difference between the variable cost of the plant and the estimated day-ahead price, i.e. the mark-up is higher if this difference is high. For instance, a plant with a variable cost of 20€/MWh will increase more easily its submitted price in absolute terms if the estimated day-ahead price is 50€/MWh than 22€/MWh (because the probability of being rejected in the second case is higher).
- If the plant does not bear any start-up costs, then the offer is made at its variable cost.
- Moreover, even if start-up costs are high, the plant never formulates a bid at a price higher than the estimated day-ahead price (the mark-up is therefore limited)
- Finally, this mark-up is re-calculated for each new estimated day-ahead price scenario in order to properly consider the new costs to be covered as well as the hours during which these costs can be covered

Moreover, in the case where several bids are submitted for the same plant, it is necessary to ensure that these bids are always increasing, that is to say that the submitted price is always increasing with the quantity (to avoid, for instance, that the optimal generation of scenario 2 is accepted before the optimal generation of scenario 1)[160]. This bidding strategy is illustrated in a simplified way for two hours and two forecast day-ahead price scenarios in figure 77.

[160] This situation is possible because of the mark up. With a higher price scenario, a plant may want to produce during more hours. Eventual start-up costs are then spread over more hours, thus reducing the mark-up. The submitted price must then be corrected to avoid this situation of decreasing bids.

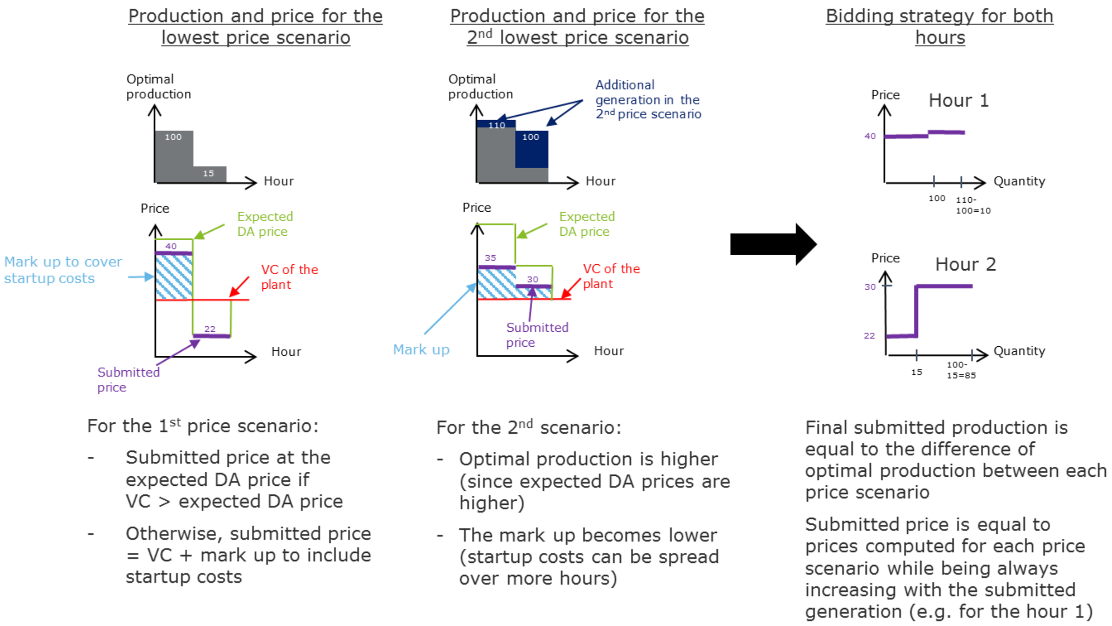

Figure 77: Simplified illustration of the bidding strategy for thermal power plants[161]

[161] DA = Day-ahead ; VC = Variable costs.

Appendix C. Bidding strategy on the day-ahead market for hydroelectric plants

Hydroelectric plants cannot follow the same bidding strategy as thermal power plants. Indeed, the thermal bids are based on the fact that the production level changes with the day-ahead price scenarios: it then enables to construct several bids for a same plant. However, due to the reservoir constraint, the expected optimal production for a hydroelectric plant is always the same regardless of the estimated day-ahead price scenarios[162]. To give more flexibility for the "hydraulic" bids (and then to avoid submitting a unique bid equal to the optimal production computed thanks to the UCM), the method suggested by Garcia-Gonzalez et al. (2006) is implemented. Two steps are distinguished in this strategy and described below.

Firstly, a "hydraulic" UCM is carried out for each BRP and for the different expected day-ahead price scenarios over up to a two-week horizon. This UCM is as follows:

$$Max\ Profit = \sum_{\substack{Hydro\ plant \\ of\ the\ BRP}} \sum_{\substack{Up\ to \\ 2\ weeks}} Q_{hy} * \widehat{P_{DA}}$$

$$Under\ the\ technical\ constraints\ of\ hydroelectric\ power\ plants$$

$$Under\ the\ constraints\ of\ the\ water\ reservoir$$

$$Under\ the\ technical\ constraints\ of\ plants\ identified\ to\ provide\ reserves$$
$$(plants\ identified\ to\ provide\ reserves = parameters\ of\ the\ UCM)$$

$With$: Q_{hy} $the\ optimal\ production\ of\ the\ hydro\ plant$

$\widehat{P_{DA}}$ $the\ estimated\ day - ahead\ price$

This UCM results in an optimal production level which is independent of the price scenario. Moreover, based on this UCM, an optimal reservoir level can be determined at

[162] To prove that, let us consider the case where there is one hour when the production is lower for scenario 1 (low expected prices) than scenario 2 (high expected prices). Because of the reservoir constraint, there is necessarily an hour when the production for scenario 1 has to higher than for scenario 2: this would mean that the plant wants to produce for a low expected day-ahead price but not for a higher price, which does not seem relevant and cannot be translated into bids submitted on the day-ahead market. Thus, the hydroelectric production must be the same regardless of the estimated day-ahead price scenarios.

the end of the first day (the day for which the BRP studies the bids to submit on the day-ahead market).

Secondly, a new UCM is performed by adding a new to fix the level of the reservoir at the end of the first day. The idea of this method is to study different non-optimal levels of reservoir at the end of the first day. A non-optimal level would then require the plant to use stored water in a different way and to produce according to a pattern different to the optimal one. In particular, if the water reservoir level imposed at the end of the first day is higher than the optimal reservoir level, the plant must produce less during the first day and more the rest of the week: the water value will therefore be lower than the water value in the optimal case (this water value is computed based on the expected day-ahead prices). The plant agrees to reduce the quantity offered on the day-ahead market for the first day if the day-ahead price is low enough so that it is more advantageous to keep water for a later use. On the contrary, with an imposed water level lower than the optimal reservoir level at the end of the first day, the plant should produce more the first day but less the rest of the week: the water value will be higher than in the optimal situation. Similarly, the plant will agree to increase the offered quantity provided that the day-ahead price will remunerate it at least as high as the water value (the plant will be then indifferent between selling this water in the day-ahead market and keeping it to produce later). The water value obtained in the different situations then represents the level that the day-ahead price must exceed so that it is more relevant to sell the water on the day-ahead market rather than to keep it in the reservoir and use it later.

The final bids of the hydroelectric power plant are formulated by considering the reservoir constraint scenarios imposed at the end of the first day by decreasing order, i.e. from the largest reservoir level to the lowest (and therefore by increasing water value order). For the highest reservoir constraint (i.e. the case where the reservoir is the largest at the end of the first day), the quantity to produce during the first day is small (this quantity comes from the resolution of the hydraulic UCM with the associated reservoir constraint at the end of the first day). In particular, this production is limited to the hours when the estimated day-ahead prices are the highest. This volume is then submitted for each hour at the corresponding water value, which is low, on the day-ahead market. For a lower reservoir constraint (i.e. the reservoir level at the end of the first day is lower), the plant necessarily produces more (or the same level): the submitted bid corresponds to the difference with the volume offered in the previous scenario. Moreover, this bid is also submitted at the corresponding water value (which is higher). This procedure is repeated for all reservoir deviations considered at the end of the first day.

Appendix D. Study of the available upward margin

In order to calculate the available upward margin of the whole system, the available margin of each plant is studied first. A distinction is made between power plants that can be activated to ensure system margin and power plants that cannot. Indeed, the purpose of the margin study is to assess whether to activate these plants. The calculation of the available margin is therefore made without considering these plants: if the available margin is sufficient, it means that it is not necessary to activate them. Otherwise, the TSO has to activate some of them.

D.1 Consideration of power plants that can be activated to ensure upward system margin

Power plants that the modelled TSO is able to activate to ensure system margin must comply with several conditions:

- Their start-up time must be lower than or equal to the time between the target time step and the moment when margins are computed
    - For example, in the case of the study of the target time step 10 a.m. 4 hours ahead (i.e. margins are calculated at 6 a.m.), power plants which start up in 8 hours should not be considered for activation to ensures system margin (regardless of the maturity). Indeed, if this unit was activated (and therefore started up) 4 hours before the target time step, it would never be able to complete its start-up before the target time step and thus to bring the missing margin.
- Their start-up time must be greater than or equal to the maturity
    - For example, for the study of the 4-hour maturity, power plants that can start up in 8 hours or 4 hours are the only plants that can be activated (respectively 8 hours and 4 hours before the target time step). Indeed, the purpose of these activations is to start up power plants that would not bring margin to the system if they were not started up by the TSO. In the case of the 4-hour maturity, a plant which is able to start up in 3 hours brings margin to the system and is therefore considered in the available margin

because its activation time (i.e. its start-up time) is lower than the maturity. The TSO does not have to activate this plant for this maturity.

- The plant must not produce during a certain duration. Indeed, if the TSO activates this plant to ensure system margin, this activation should not be in contradiction with the generation schedule determined by the BRP which owns it.
  - The TSO can only activate plants which are offline and that BRPs do not plan to start up and use to produce
  - In particular, the potential activation of plants by the TSO should not be in contradiction with the planned generation schedule both during the activation period (i.e. the period during which the TSO requires the power plant to start up, produce and shut down) but also for a certain duration after the shutdown (because of the minimum down time constraint)
  - The key assumptions behind these constraints is that the BRP which owns the activated plant keeps a priority to use it: if the activation to ensure system margin that the TSO wants to perform is not technically compatible with the planned generation schedule of the plant determined by the BRP, then the TSO cannot activate it[163].

Once the plants that can be activated to ensure upward system margin are identified by the TSO, it is necessary to see how these plants are taken into account in the available margin. Theoretically, these plants should not be considered in the available margin so that the TSO can assess whether it needs to activate them or not. However, practically, the French TSO considers part of these plants in the available margin. More precisely, power plants which can be activated (according to the previous criteria) and whose start-up time is strictly lower than the duration between the target time step and the time step when computation is made are actually considered in the available margin. For instance, 8 hours before the target time step, CCGT plants which can be activated to ensure system margin and which start up in 3 hours or 4 hours are considered in the available margin.

[163] However, if a plant can be activated to ensure system margin and if the TSO activates it, this decision is definitive. In particular, the BRP which owns the plant cannot force the TSO to cancel its decision.

Moreover, the French TSO considers that the available margin of these plants is equal to their minimum output.

The underlying idea behind this consideration is that, X hours before the target time step, the purpose of the margin study is to evaluate the activation need for power plants which start up in X hours only. Activation of plants whose start-up time is Y <X hours, although perhaps necessary, may wait and will be decided only Y hours before the target time step: power plants are then activated at the last moment. Thus, in order to study the need to activate plants whose start-up time is X hours only, the French TSO considers that power plants whose start-up time is Y hours (with Y <X) and which can be activated to ensure system margin participate implicitly to the available margin: this implicit consideration reflects the possibility for the TSO of activating them later (i.e. the decision does not have to be made immediately). If the available margin is not sufficient even when considering the power plants which can be activated and whose start-up time is strictly lower than X hours, then the TSO has to activate plants whose start-up time is X hours. Otherwise, their activation is not necessary. However, this does not mean that the TSO will not activate any power plant to ensure margin: it will maybe have to activate power plants whose start-up time is equal to Y hours but it will do it only Y hours before the target time step.

Making the activation decisions as close as possible to the start-up time of the power plant enables the TSO to activate plants only when it is really necessary and thus to minimize the costs of these activations to ensure system margin. Indeed, activation at the last possible moment enables the TSO to have a better vision for the target time step.

D.2 Consideration of power plants that cannot be activated to ensure upward system margin

For plants that cannot be activated to ensure system margin, the available upward margin of each plant is calculated by the French TSO as the maximum output that the plant can reach by modifying its generation during the maturity period only minus what it intends to produce for the target time step (see figure 78 for two examples). Therefore, this available margin for each plant mainly depends on its technical constraints (its ramping constraints and its maximum output). In particular, what happens after the target time step is not considered by the TSO when calculating the available margins: only the difference between what the plant intends to produce for the target time step and what it can produce in the best case matters. Of course, this available margin will not be activated by the TSO:

it is simply a guarantee for it to have enough margins to manage the system in a secure way, in particular if large imbalances occur before the real time.

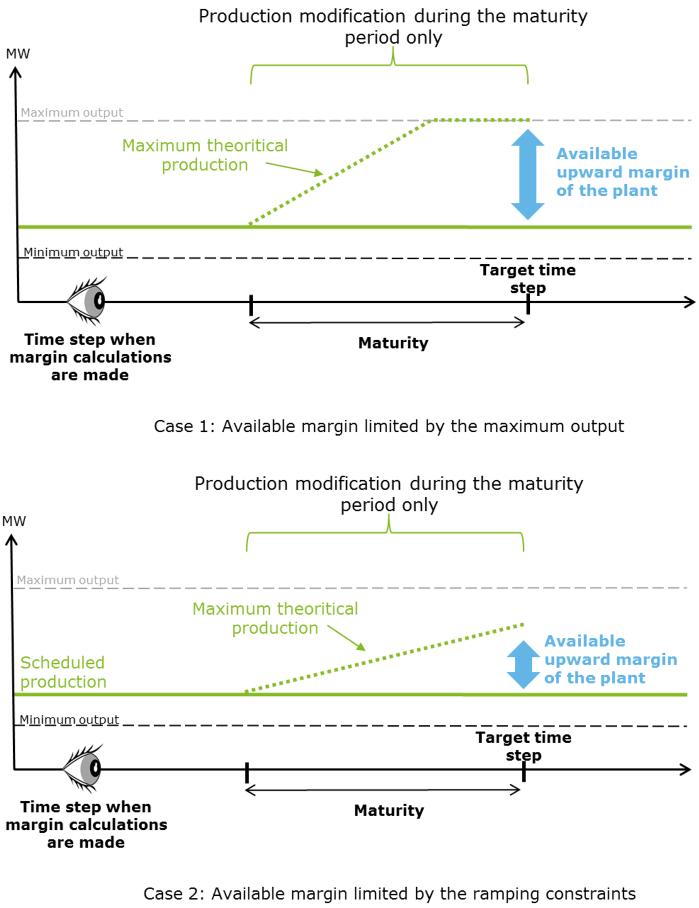

Figure 78: Illustration of the available upward margin for an online plant in two cases

D.3 Total available margin

Once the available upward margin for each plant is calculated, the available system margin is calculated as the sum of the available margin for each plant. In addition, the aggregated imbalances of the whole system as anticipated by the TSO should be considered in this computation: indeed, if the system is negatively imbalanced, the TSO has to ensure a higher level of available upward margin: part of this margin has to be available to solve the system imbalances and the other part deals with the possible uncertainties which can occur before the real time. Similar reasoning applies if the system is positively imbalanced. In the modelling, this anticipated system imbalance for the target time step is calculated as the difference between the sum of the generation schedule of all power plants and the forecast of the residual consumption made by the TSO.

Appendix E. Study of the available downward margin

The calculation of the downward margin for each plant performed by the French TSO is slightly different from the upward margin. Indeed, the downward margin is computed as the greatest decrease of generation that plants can reach in 30 minutes only (and not over the entire maturity), as shown in figure 79.

The available downward margin for the whole system is then calculated as the sum of the available margins for each plant from which should be subtracted the anticipated imbalances of the whole system (but conversely to the upward margin, a negatively imbalanced system increases the available downward margin).

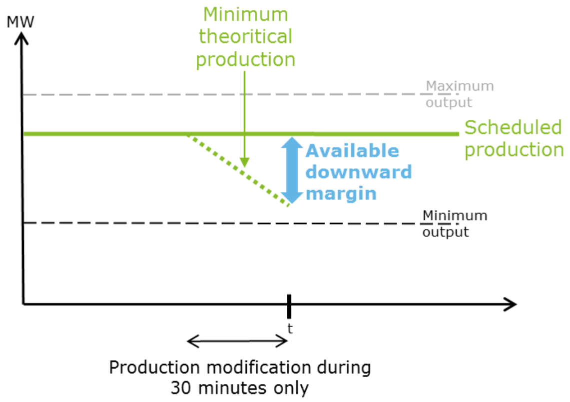

Figure 79: Illustration of the computation of the available downward margin

Appendix F. Details on power plants parameters

F.1 Start-up of combustion turbines

Once the start-up decision has been made, combustion turbines are considered able to produce in 30 minutes. However, the production level they are able to reach in 30 minutes varies. Indeed, according to discussions with the French TSO, during these 30 minutes required to start up, 15 minutes are needed to perform preliminary actions during which production remains equal to zero. Thus, if the start-up decision is made at the last moment, it is considered that combustion turbines can only reach half their maximum output in 30 minutes since the first 15 minutes are used to perform these preliminary actions. However, if they can anticipate the start-up decision and therefore perform preliminary actions in advance, they can reach their maximum output in 30 minutes.

The first situation corresponds to cases where decisions to start up are made at the last moment, i.e. 30 minutes before the real time. It is notably the case on the balancing mechanism where the TSO activates plants 30 minutes ahead: then, combustion turbines cannot anticipate the start-up and can produce only up to half their maximum output in 30 minutes. As a result, procured RR products provided by offline combustion turbines are limited by this point: they cannot provide a volume of RR equal to their maximum output since this volume cannot be activated in 30 minutes. The second situation corresponds to cases where plants can anticipate their start-up. For instance, bids submitted on the day-ahead market or on the intraday market consider that combustion turbines can reach their maximum output in 30 minutes. Indeed, in this case, generation schedule is planned well before the real time (for instance during the rescheduling stage) and start-up decisions can then be foreseen by BRPs.

F.2 Technical parameters of the French nuclear plants

Since start-up and shutdown of nuclear power plants are not considered in the modelling, only the minimum output, ramping and variable cost parameters are required. Moreover, it appears that the ramping technical values encountered in the papers mentioned in the chapter 3 seem weak compared to the abilities of the French nuclear plants (the average value mentioned in the literature is about 160MW/h). This can be explained by the greater flexibility of the French nuclear fleet, which was designed to carry out load following (EDF, 2013; Lokhov, 2011), compared to more traditional nuclear plants in other countries. More specifically, these two references highlight that this flexibility varies during the fuel cycle. During a first phase after refuelling, a nuclear plant is highly flexible: its minimum output is low and its ramping capabilities are important. However, at the end of the fuel cycle, its flexibility decreases quickly. Based on the historical production data of the French nuclear plants for 2014 and 2015 (available on the website of the French TSO), minimum outputs and hourly ramping abilities are measured at the beginning and the end of the fuel cycle. Figure 80 illustrates this flexibility for one French nuclear plant.

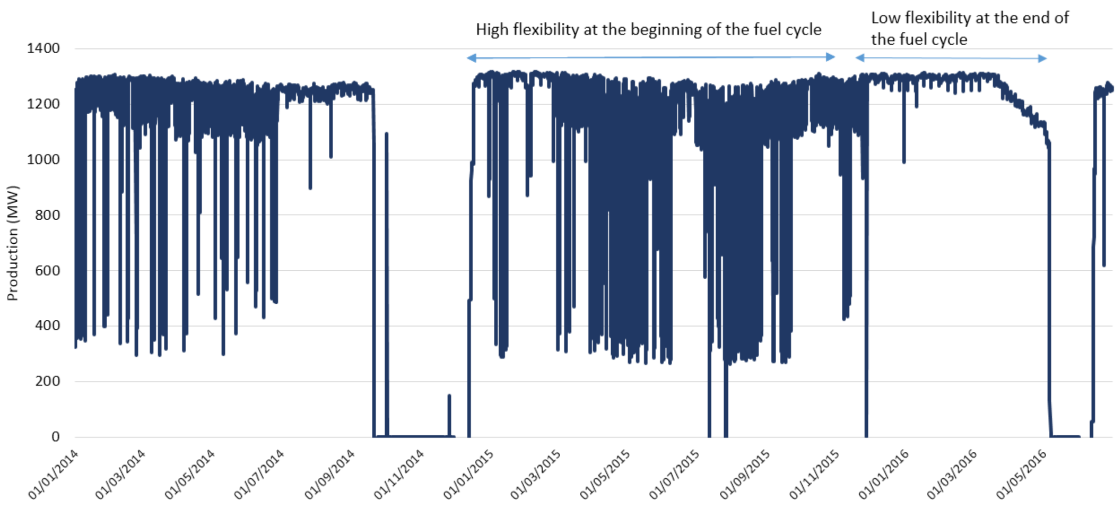

Figure 80: Load following possibilities of a French nuclear plant

Moreover, it is considered that a nuclear plant is in a high flexibility stage during the first 65% of the fuel cycle, a low flexibility stage during the last 10% and in an

intermediate stage the rest of the time (EDF, 2013). It is then possible to compute average technical parameters for French nuclear plants independently of the fuel cycle progress[164]. Moreover, these parameters appear to be different for the three design classes built in France (900MW, 1,300 MW and 1,500MW): these values are presented in table 20. The average ramping characteristics (295MW/h) is higher than data available in the literature, reflecting the higher flexibility of the French nuclear plants.

[164] Since not all reactors are at the beginning of their fuel cycle at the same time, it is necessary to have an approximate duration of each stage of the fuel cycle to calculate average technical parameters which are independent of the fuel cycle progress.

Table 20: Considered technical parameters for the French nuclear plants

Class	Min. output (MW and % of max capacity)	Ramping rate (MW/h)
900 MW	570 MW – 63%	200 MW/h
1,300 MW	610 MW – 47%	440 MW/h
1,500 MW	825 MW – 55%	380 MW/h

F.3 Parameters of the hydroelectric plants

As explained in the chapter concerning the modelling, a unique equivalent hydroelectric power plant is considered for each BRP. However, even if this choice greatly simplifies the modelling, the determination of the parameters of the equivalent power plant (namely its maximum output and the quantity of water it can use to produce over two weeks, i.e. its reservoir constraint) remains very complex because of the very limited available data for the French power system. To approximate these values, a spectral analysis of the total hydroelectric production for 2013 in France is performed[165]. Thanks to this analysis, it is possible to distinguish production components corresponding to daily variations (i.e. variation of the production within a day) and to weekly variations (i.e. variation of the production within a week). Components that do not correspond to these two time horizons are not considered for the modelled dispatchable hydroelectric plant. In particular, production variations within a month or a year will be considered in the non-dispatchable hydroelectric plant since the modelled hydraulic UCM does not perform a trade-off in the use of water over more than 2 weeks. Similarly, run-of-the-river generation, which is assumed not to follow any particular periodicity, is not considered for the dispatchable hydroelectric plant.

Thus, a theoretical production corresponding to the daily and weekly generation variations can be built (see figure 81, which starts on Monday[166]). The classic variations

[165] Production data is available on the website of the French TSO. Moreover, the analysis is also carried out for 2014 and 2015. However, the results for these years are difficult to exploit and then ignored.

[166] It should be noted that the production pattern of figure 81 is not necessary the one that will be observed in the results of the simulation. Indeed, this production scheme is not imposed on BRPs. It simply enables to define the technical values (maximum output and quantity of water which must be used over two weeks) which are used as input parameters for the hydraulic UCM. The actual production of the equivalent hydroelectric power plant will be determined by the resolution of the UCM and the agents' decisions.

between day and night, as well as ones between weekdays and weekends, can be noticed. Thanks to this theoretical generation over one week, the maximum output of the dispatchable and equivalent hydroelectric plant (namely 5,650 MW) and the corresponding level of water used to produce over two weeks (thanks to the integral of the production pattern over two weeks) can be determined. Moreover, these parameters are considered identical all year long. These values are then shared between BRPs which own dispatchable hydroelectric plants (namely EDF and ENGIE) in proportion to their dispatchable hydroelectric plants currently installed in France.

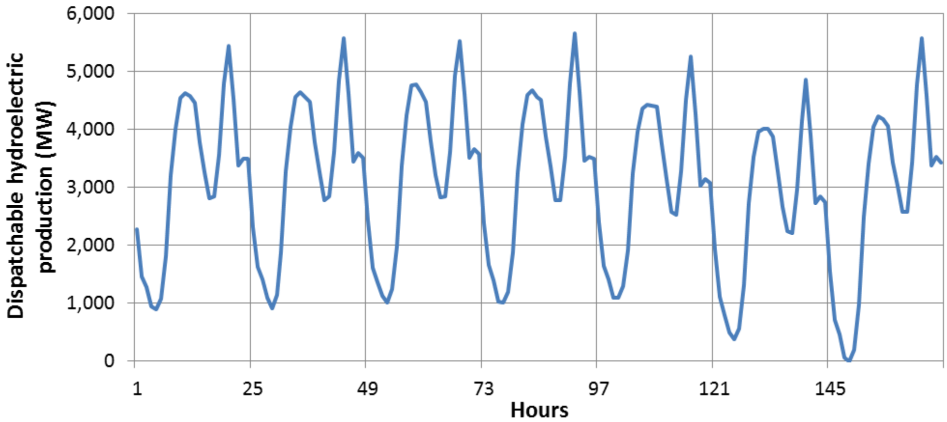

Figure 81: Computed daily and weekly production variation of all French hydroelectric plants based on 2013 data

The non-dispatchable hydroelectric production can then be determined as the difference between the total hydroelectric production observed in 2013 in France and the theoretical dispatchable hydroelectric production illustrated on figure 81. It represents run-of-the-river generation and generation resulting from a trade-off over more than two weeks. This production is also distributed among the modelled BRPs which own hydroelectric generation facilities (EDF, ENGIE and the residual RE) in proportion to their hydroelectric plants currently installed in France. Moreover, this non-dispatchable hydroelectric production cannot be modified by BRPs in the modelling, either because it corresponds to run-of-the-river generation or because it involves trade-off which are not considered with the UCM. Then, this production is subtracted to the consumption to define the residual demand.

Appendix G. Electricity consumption parameters

G.1 French consumption parameters

The French national consumption is determined based of the estimated consumption in the Generation Adequacy Report. This consumption varies between 31 and 85 GW within the year[167]. Moreover, in this report, this consumption is divided between the Residential and the Non-Residential (industry, tertiary, transport and energy) sectors. Thanks to data published by the French regulator regarding the market share of each BRP in the retail market depending on the type of consumer (CRE, 2015), the estimated market shares of national consumption for each modelled BRP can be computed (table 21).

Table 21: Estimated market share for each modelled BRP

	EDF	ENGIE	Alpiq	EON	Direct Energie	Residual
Residential	90%	7%	0%	0%	3%	0%
Tertiary + Industry + Transport + Energy	65%	12%	4%	5%	3%	12%

Uncertainties about the consumption are also modelled with a normal distribution whose parameters are defined in the chapter 3. These forecast errors should be shared among BRPs. In the absence of precise data, it is decided to share these errors in proportion to the thermosensitivity[168] of the consumption portfolio. Indeed, this thermosensitivity depends on the type of consumers and is higher for residential consumption (ERDF, 2015; RTE, 2014)[169]. As a result, portfolios with a large share of residential consumers have a higher sensitivity and therefore a higher prediction error than BRPs with only industrial consumers.

[167] Data is available on https://opendata.rte-france.com/pages/accueil/. Moreover, the French TSO estimates the consumption for 2019-2020. However, since consumption differences are very small between 2017 and 2019, the same level of demand is considered for 2017 in this modelling.
[168] The thermosensitivity measures how power consumption varies with temperature.
[169] In particular, the thermosensitivity is estimated at 1,250 MW/°C for residential consumers, 386 MW/°C for the industry and tertiary sectors and at 200 MW/°C for the power losses.

G.2 Consideration of the interconnections

Because of their importance for the French power system (about 12% of produced electricity is exported), volumes exchanged with border countries are taken into account in the modelling. However, due to the complexity of a rigorous modelling of these interconnections (which would require consideration of what is happening in foreign countries, and in particular the levels of supply and demand in these countries), demand (or supply) resulting from the interconnections is considered exogenous and determined based on a simple econometric study. More particularly, this study assesses the relationship between the current volume exchanged on all interconnections with France on the day-ahead and intraday horizons and the French residual demand. Volumes exchanged at these two horizons are calculated using the day-ahead and intraday nomination data available on the website of the French TSO. Results for 2014 and 2015 and for the day-ahead exchanges are presented in figure 82.

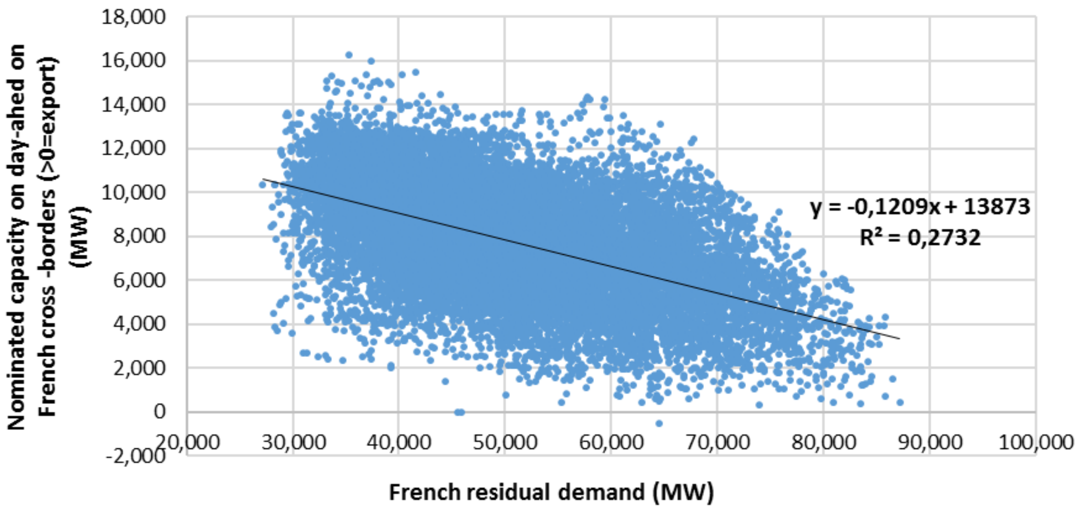

Figure 82: Relation between French residual demand and day-ahead exchanges on cross-borders for 2014 and 2015

A correlation between the level of consumption in France and the exchanged volumes can be noticed and seems relevant. During periods of low demand, the French power system exports large quantity of electricity while it greatly reduces its exports (or even imports) during peak periods. However, it should be noted that the coefficient of determination is very low. Indeed, many parameters other than the French demand (for example, the availability of nuclear plants in France, the levels of supply and demand in foreign countries) can modify the exchanged quantity and should be taken into account in the econometric study. In conclusion, the regression depicted in figure 82 is used to model the day-ahead demand (or supply) resulting from the interconnections. This demand is added (or subtracted if it is negative) to BRPs' consumption in proportion to their national consumption. Moreover, no uncertainties are considered for this demand.

For the intraday horizon (i.e. exchanges decided after the day-ahead market but before the real time), results do not show any relevant correlation: demand (or supply) from border countries at this time horizon is then not considered in this modelling.

Appendix H. Parameters defining the French security model

H.1 Determination of the target time step

The available upward margins for the 8-hour, 4-hour and 3-hour maturities are not studied for all time steps of the day but only for those which belong to the morning peak and the evening peak periods. Since there are no criteria available in the literature to define these peaks, a rapid analysis of the peak periods for 2015 and available on website of the French TSO[170] is carried out. Even if the time range of peak periods is rather heterogeneous, it is possible to notice seasonal trends. For example, the evening peak period is not defined for weekdays during summer. Final values of the peak periods considered in the modelling are given in table 22: these values are defined as the average observed values for 2015.

Table 22: Considered values for the target time steps for the 8-hour, 4-hour and 3-hour maturities

	January	**February**	**March**	**April**		**May**	**June**
				1st fortnight	2nd fortnight		
Morning peak during weekdays	7.30am-1.30pm	7.30am-1.30pm	7.30am-1.30pm	7.30am-1.30pm	8.30am-2.30pm	8.30am-2.30pm	9am-3pm
Evening peak during weekdays	6pm-8pm	6pm-8pm	6.30pm-8.30pm	No margin study for the 8h, 4h and 3h maturities			
Morning peak during weekends	9am-2pm	9am-2pm	9am-2pm	9am-2pm	9am-2pm	9am-2pm	9am-2pm
Evening peak during weekends	6pm-9pm	6pm-9pm	6pm-9pm	7pm-12am	7pm-12am	7pm-12am	7pm-12am

	July	**August**	**September**		**October**	**Nov.**	**Dec.**
			1st fortnight	2nd fortnight			
Morning peak during weekdays	9am-3pm	9am-3pm	9am-3pm	9am-3pm	7.30am-1.30pm	7.30am-1.30pm	7.30am-1.30pm
Evening peak during weekdays	No margin study for the 8h, 4h and 3h maturities			6.30pm-9pm	6.30pm-8.30pm	6pm-8pm	6pm-8pm
Morning peak during weekends	9am-2pm	9am-2pm	9am-2pm	9am-2pm	9am-2pm	9am-2pm	9am-2pm
Evening peak during weekends	7pm-12am	7pm-12am	7pm-12am	7pm-12am	6pm-8pm	6pm-8pm	6pm-8pm

H.2 Determination of the required margins for each maturity

H.2.1. Upward required margin

Required margins should be defined for the same maturities as the available margins, namely for 8 hours, 4 hours, 3 hours, 2 hours and 30 minutes. Concerning the last two maturities, their value is constant and has been communicated by the French TSO: the

[170] http://clients.rte-france.com/lang/fr/visiteurs/vie/mecanisme/jour/marges.jsp

required margin for the 2-hour maturity is equal to 2,300 MW and the required margin for the 30-minute maturity is equal to 1,615 MW. Regarding the other maturities, their value is not constant and depends on many parameters (notably the forecast consumption) in order to better reflect actual risks of imbalances. Since there are no formulas available in the literature to compute exactly these required margins, a rapid analysis of the required margins in 2015 for the 8-hour maturity[171] is carried out. As for the target time step, it is possible to notice seasonal trends. Moreover, various regressions are studied to try to explain the values of required margin using the expected consumption and wind and PV productions as explanatory variables. These regressions are done separately for the different seasons and for weekdays and weekends. Results highlight that there are no relationships between the required margin and wind or PV productions (or very low for few MW which is not considered here). Regarding the consumption, only the required margin for the morning peak period in winter shows a significant correlation with consumption, both for weekdays and weekends. Then, these regressions are used in the modelling to calculate the required margin for the morning peak. For other cases, the required margin values are constant most of the time and/or cannot be explained simply by the econometric study (in particular because of the small number of observations). Then, the required margin is considered as exogenous and constant. However, it can depend on the season and/or day of the week. These values are summarized in table 23.

Table 23: Required margin for the 8-hour maturity

	Jan	Febr	March	April	May		June	
					1st fortnight	2nd fortnight	1st fortnight	2nd fortnight
Morning peak during weekdays	Regression[172]					Interpolation between 3,500 and 2,500		2,500
Evening peak during weekdays	3,000	3,000	3,000	No margin study for the 8h maturity				
Morning peak during weekends	Regression[173]					Interpolation between 3,400 and 2,300		2,300
Evening peak during weekends	3,100	3,100	3,100	3,100	3,100	Interpolation between 3,100 and 2,300		2,300

[171] These values are available on http://clients.rte-france.com/lang/fr/visiteurs/vie/mecanisme/jour/marges.jsp
[172] The computed and considered regression is: Required margin = 2550 + 0.0215*(French Consumption).
[173] The computed and considered regression is: Required margin = 2790 + 0.0131*(French Consumption).

	July	August	September		October	Nov.	Dec.
			1st fortnight	2nd fortnight			
Morning peak during weekdays	2,500	2,500	2,500	Interpolation between 2,500 and 3,500		Regression	
Evening peak during weekdays	No margin study for the 8h maturity			Interpolation between 2,300 and 3,000		3,000	3,000
Morning peak during weekends	2,300	2,300	2,300	Interpolation between 2,300 and 3,400		Regression	
Evening peak during weekends	2,300	2,300	2,300	Interpolation between 2,300 and 3,100		3,100	3,100

By using these average required margin values and ignoring the extreme ones, there is a risk of underestimating the required margin during certain hours, and thus minimizing activations to ensure system margin. However, based on data for 2015, it can be noticed that for this year activations to ensure upward system margin did not correspond to periods when the required margins were the highest. Then, the use of an average value for the required margin in the modelling does not appear to result in an underestimation of activations to ensure system margin.

As a result, the analysis of the data for 2015 enables to define the required margin for the 8-hour maturity, depending on the period of the year and the consumption level. For the other maturities (4 hours and 3 hours), in the absence of similar data, a simple linear interpolation is carried out between the required margin for the 8-hour maturity and the required margin for the 2-hour maturity (which is always equal to 2,300 MW).

H.2.2. Downward required margin

Downward margins are studied for the 2-hour maturity only. The related required margin is constant and has been communicated by the French TSO: it is equal to 1,250 MW.

Appendix I. Correction of the demand which has to be supplied by dispatchable power plants

Based on the national consumption, on the generation considered as non-dispatchable and on the formula used to compute foreign demand, the final demand that should be covered by dispatchable plants (thermal and hydroelectric) can be computed. However, it appears that, except in summer, the modelled dispatchable plants are not able to cover the residual demand for many hours: rolling blackouts would then be often necessary for large quantities in this modelling. Several reasons may explain these particular situations. First of all, the modelling does not consider all plants available to produce in France. This is especially true during peak periods when technologies which usually do not bid on the energy markets become available to produce due to high prices (e.g. decentralized thermal power plants or demand response). But above all, the particular situations previously mentioned are explained by the exogenous consideration of interconnections which represents very poorly the actual situation in France. Indeed, the coefficient of determination of the regression performed in appendix G is very low. Many parameters that may explain the demand resulting from interconnections are not considered within this regression (for instance, the levels of demand and supply in foreign countries, the total capacity available in France). In particular, it seems irrelevant in the modelling that the French system exports electricity (the calculated foreign demand is always positive and is equal to at least 3 GW) even though there are not enough plants to produce, resulting in rolling blackouts. The demand for electricity is therefore overestimated.

An overestimated demand coupled with an underestimated supply necessarily leads to an impossible balance for many hours. The modelled power system is too constrained and does not represent the current (or future) situation in France. The demand coming from the interconnections must therefore be corrected in order to avoid the problematic situations which are irrelevant and which would greatly limit the comparative analysis.

<u>To what extent should the demand (or supply) coming from the interconnections be corrected?</u>

Several solutions seem possible to determine to what extent foreign demand should be reduced in order to ensure a correct and relevant functioning of the modelled French system for both security models. The first and simplest solution would be to reduce the final demand[174] so that its maximum value is equal to the maximum generation level that can be produced by dispatchable plants. Then, rolling blackouts should be avoided. However, even with this correction, the functioning of the system could be constrained in both security models and the related situations may not be relevant for the French system power.

Firstly, in the alternative security model, an additional upward volume of 1.8 GW is procured compared to the French security model. Although this 1.8 GW can produce on the balancing mechanism, this volume is not available on the day-ahead and intraday markets. Then, if the final demand on these markets is too high, there will be a lack of supply: energy price will be defined at its price cap and BRPs will be negatively imbalanced since they will not be able to buy enough energy to cover the consumption of their clients. This situation may be surprising since the modelled French power system still exports electricity during these hours[175]. Then, the first criterion to correct the final demand level requires that the maximal final demand during the simulated week to be lower than the maximum generation level that can be supplied on the day-ahead market in the alternative security model (i.e. the sum of the maximum output of dispatchable plants minus all upward procured reserves).

Secondly, the possible issues with the study of upward margins in the French security model have also to be considered. Indeed, if the final demand is too close to the system's total maximum output, then the available upward margin (which in the best case is equal to the difference between these two quantities) may be too low. The TSO would then require performing activations to ensure the upward margin. However, since all plants are already producing (because demand is high), it may be unable to activate enough plants and security would be jeopardized.

To illustrate this, let us consider the theoretical case where the TSO studies long before the target time step (for example 10 hours before) the available upward margin for a 8-hour maturity. Moreover, let us consider an anticipated final demand of 50 GW and a

[174] Final demand is here defined as the energy demand that should be covered by dispatchable plants only, namely the French consumption minus generation from non-dispatchable plants plus (or minus) demand (or supply) resulting from the interconnections.

[175] Given current observations, when the national supply-demand balance is tight, the French power system imports electricity. Then, it seems irrelevant to consider in the modelling that the French power system exports electricity in this situation.

maximum output for the whole system of 52 GW. In the best case, the available margin for the 8-hour maturity as calculated long before the target time step is equal to: 52-50 = 2 GW (i.e. the maximum increase of production). In particular, coal-fired and CCGT plants that can be activated later to ensure system margin are implicitly considered in the available margin since their start up times are strictly lower than 10 hours. If the required margin is greater than this level (which is possible given data presented in appendix H), a security issue appears. Indeed, in this case, the TSO does not have any plants which can be activated to ensure system margin since there are no power plants whose start-up time is equal to 10 hours. Moreover, activating coal-fired or CCGT plants would not increase the available margin since they are already implicitly considered in the available margin. Then, in this case, the TSO would be unable to ensure the security of the system.

However, this extreme situation where the available upward margin for the 8-hour maturity and as calculated 10 hours before the target time step is lower than the required margin is practically impossible. To be convinced of this, the upward available and required margins published by the French TSO have been studied[176]. These published margins correspond to an 8-hour maturity and are calculated at 8 p.m. the day before the morning peak, i.e. at least 10 hours before the target time step (the morning peak starts at 6 a.m. at the earliest). Available margins published by the French TSO are then similar to the available margin described in the previous paragraph. Based on this data, it appears that in 2014 and 2015 this available margin was never lower than the required margin for the same 8-hour maturity except for 3 morning peak periods only. It means that the TSO is (almost) never confronted with the aforementioned problem where it would have been unable to activate plants to ensure system margin more than 8 hours before the target time step.

Thus, it is relevant to also correct the final demand to avoid these problematic situations in the French security model since they are almost impossible in reality. By doing this, the three cases mentioned above are neglected. However, this modelling aims at comparing both security models for average scenarios and not at studying precisely a very specific situation. In these very particular situations, a better representation of the available margin and the plants which can be activated to ensure system margin would be

[176] These values are available on http://clients.rte-france.com/lang/fr/visiteurs/vie/mecanisme/jour/marges.jsp

required to model precisely what would happen in the French security model. Therefore, the second correction criterion requires that the final demand during the simulated week to be low enough so that the available upward margins for the 8-hour maturity and calculated long before the target time step (more than 8h30 before in order to consider coal-fired plants which can be activated to ensure system margin in the available margin) are always greater than the required margin for the same 8-hour maturity. Thus, the TSO never needs to activate power plants to ensure system margin whose start-up times are strictly higher than 8 hours, which would be impossible in the modelling (but possible in reality thanks to other solutions, such as demand response, which are not considered in the modelling). It should be noted that this correction does not prevent activations to ensure system margin, which may be necessary for lower maturities or for plants whose start-up time is less than or equal to 8 hours.

Demand resulting from the interconnections is therefore corrected so that the final demand respects both previously mentioned criteria[177]. Then, situations that are irrelevant for both security models are not considered. Moreover, final demand is modified in the same way in both security models, i.e. the same final demand is supplied in both models, based on the most constrained criterion, to ensure a proper comparison.

With these corrections, situations with a very high final demand and which would require producing with almost all modelled plants cannot be considered in the modelling since they will result in impossibilities to solve the problem for both security models. A complementary study, which considers in a better way interconnections and capacities available during peak periods, would then be necessary to complete the results.

[177] Practically, a reduction factor is calculated so that the maximum final demand over the week is defined at the maximum possible level while respecting both criteria. The demand for the rest of the week is then reduced using the same factor. It enables to keep the same pattern for the demand profile and to avoid reducing the peak demand only.

Appendix J. Weeks considered for the simulations

Once the final demand has been corrected to avoid any irrelevant situations for both security models, the weeks considered for the simulations can be studied. Given the computation time constraints (the resolution for one week takes about one to two hours for the French model and two to four hours for the alternative model), simulations are done over a reduced number of weeks. To ensure a good representativeness of the results over the whole year, a week of winter, summer and mid-season are considered. For each studied week, it is therefore necessary to define the time-dependent input parameters that will be used in the simulation (e.g. the value of nuclear availability, the level of consumption). To define these parameters, a distinction is made between parameters whose values are different for each time step (like for the consumption) and parameters that are constant over a certain period (for example, the availability of nuclear plants).

With regard to the first type of parameters (i.e. for the national consumption and generation from PV, wind and non-dispatchable hydroelectric plants), to avoid choosing a random week during the winter, summer and mid-season periods, the average value over the studied period is considered. For instance, the average consumption for each Monday for 8 a.m. to 8:30 a.m. is computed over the entire considered winter period. This choice enables to simulate both security models for one week with an "average" residual demand.

Regarding the parameters that are constant over a certain time period (e.g. nuclear availability or parameters associated with the margins study), it should be ensured that these parameters can be considered as constant over the period for which previous averages were calculated. For example, it is not possible to consider the average of residual demand over the entire winter period from December to February because the availability of nuclear plants is not constant over this period. If the entire winter period were studied, there would be an issue to define the availability of nuclear plants: should the value for December be considered? Or the value for February? Thus, the periods considered for the simulations, and for which averages are calculated for the first type of input parameters, have to be defined in a way that the second type of input parameters can be considered as constant over this period. Then, selected periods which respect this point are:

- The month of January to represent a winter period (before and after this month, the availability of nuclear plants is no longer the same). The residual demand is therefore calculated based on the average values for the whole month of January.

- From November 15th to December 1st and from March 1st to March 15th for the mid-season period (similarly, the availability of nuclear plants is different outside this period)[178]

- From June 15th to September 15th for the summer period (the required margin is different after this period).

[178] The definition of the peak period is not exactly the same within this period. However, the difference is small: the longest time range will be retained for this period.

Appendix K. Construction of expected day-ahead price scenarios

BRPs use anticipated day-ahead price scenarios to compute their opportunity cost of providing reserves and to define their bids on the day-ahead market. Attention should be paid to the estimation of these price scenarios. Indeed, for the construction of bids on the day-ahead market, BRPs are considered to be price takers: thus, the price estimate has a strong influence on their bids and the results of this market. For example, if the estimated day-ahead price is too low (because BRPs have underestimated demand), plants will not want to start up and produce based on the UCM results and will not submit any bids: the lack of supply bids will result in a high realized day-ahead price, contrary to what BRPs had expected. This situation could occur in the modelling since the defined bidding strategy is not flexible enough to consider cases where BRPs poorly forecast prices (in particular when they underestimate them). A methodology to forecast these prices, based on a simplified merit-order, is defined below.

First, it is considered that BRPs can correctly anticipate the demand on the day-ahead market for each hour of the day to come.

Regarding the supply level, BRPs have to forecast technologies which will provide upward reserves and then which will not be able to produce and sell energy at their maximum output. Among the upward reserves to be provided, BRPs expect that up to around 900 MW can be provided by combustion turbines while being offline and then at a zero opportunity cost[179]: these plants are then not able to sell energy on the day-ahead market. However, being extra-peak technologies, they are not expected to modify the merit order and then the day-ahead price forecasts. Since 2.3 GW should be provided upward in the alternative security model, BRPs need to forecast which technology(ies) will provide the remaining volume. However, the opportunity costs of each technology will depend on the expected day-ahead prices, where these prices depend themselves on the technology identified to provide the reserves. For instance, if, before the reserves procurement market, BRPs expect that hydroelectric plants will provide the reserves, this will increase the expected day-ahead prices since these mid-merit plants will not be able to produce at their maximum output. However, BRPs will use this expected day-ahead

[179] These plants are never expected to produce given the level of demand. They do not forgo any profits of the day-ahead market when providing upward reserves.

price to compute the opportunity costs of providing upward reserves within their portfolio and this expected price may modify plants that BRPs previously identified to provide upward reserves. For instance, if the expected day-ahead price is high because hydroelectric plants are expected to provide upward reserves, the opportunity costs of coal-fired and CCGT plants to provide the reserves will decrease and those of hydroelectric plants will increase. Indeed, in a simplified way, this opportunity cost can be computed as the difference between the expected day-ahead price and the variable costs. The higher the variable costs, the lower the opportunity costs. Consequently, it is possible that BRPs finally decide to provide upward reserves with their CCGT or coal-fired plants because of their lowest opportunity cost. Then, on the day-ahead market, hydroelectric plants can produce up to their maximum output and will tend to decrease the price compared to what was expected before the procurement stage. Forecast of plants identified to provide reserves and expected day-ahead prices are then complex for BRPs since these forecasts are highly dependent. To simplify the problem for the alternative security model[180], it is assumed that BRPs consider two situations regarding technology identified to provide upward reserves: one where all remaining volume is provided by hydroelectric plants (which then reduce their production on the day-ahead market) and one where all remaining volume is provided by coal-fired plants or CCGT plants (which are also expected to reduce their production they sell on the day-ahead market) [181]. The actual situation will be probably between these two extremes cases.

Regarding the provision of downward RR, BRPs expect that they will be provided by baseload plants without modifying the merit-order (as it will be verified in the results).

Based on the plants identified to provide upward reserves (and which will decrease their output on the day-ahead market), a simple merit-order without considering technical constraints (except the maximum output constraint) is performed. The different technologies are stacked by increasing variable cost. Hydroelectric plants are included into this merit-order at a slightly higher cost than nuclear plants. Indeed, due to their water reservoir constraints over two weeks, hydroelectric plants are expected to be used by

[180] This issue does not occur in the French security model since combustion turbines can provide all upward reserves at a zero opportunity cost.

[181] As a baseload technology, opportunity costs of nuclear plants to provide upward RR will be higher than those of mid-merit hydroelectric plants. The case where nuclear plants are identified to provide these reserves and then reduce their bids on the day-ahead market is not considered.

BRPs once nuclear plants produce at their maximum output, as it will be seen in the results section: the associated water value is then very close (but slightly higher) to the variable cost of nuclear plants. Each technology can produce up to its maximum output minus the amount of reserves it is expected to provide. An illustration of this merit order is given in figure 83 (the first day is a Monday).

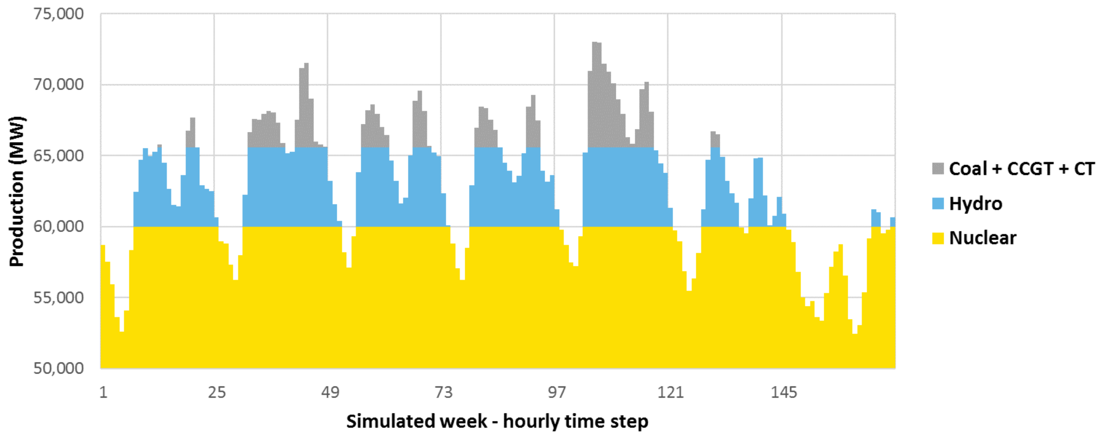

Figure 83: Illustration of the simplified merit-order without considering technical constraints for one winter week

Thanks to the results of the simplified merit-order, it is possible to anticipate when nuclear plants, hydroelectric plants or fossil-fuel plants will produce and be marginal for each hour of the simulated week (no distinction is made and necessary between coal-fired and CCGT plants). Indeed, even without considering technical constraints (except the maximum output), it is relevant to think that production of nuclear and hydroelectric plants can be correctly anticipated. Since nuclear plants are the cheapest modelled technology and have very few modelled technical constraints (in particular, start-up is not considered), they will always seek to produce as much as possible as base-load production. Hydroelectric plants are the next technology in the merit-order and they do not have any modelled technical constraints (except the maximum output): this technology will also always try to produce as much as possible once nuclear plants produce at their maximum output. Then, fossil-fuel plants will be marginal in the remaining hours when nuclear or hydroelectric plants are not marginal. However, it is difficult to predict precisely which technology, among coal-fired plants, CCGT plants or combustion turbines, will be marginal given the importance of the technical constraints and the influence of start-up costs compared to nuclear and hydroelectric plants. For instance, if fossil-fuel plants are expected to be marginal during one hour, a BRP may prefer to start up a combustion turbine during that hour than a coal-fired plant whose start-up costs are higher. However, this distinction is not necessary for the estimation of day-ahead prices which is made here.

Based on the forecast of the marginal technology for each hour, BRPs will then try estimating the corresponding day-ahead prices. When nuclear or hydroelectric plants are marginal, there are almost no uncertainties about the day-ahead price: it is defined by the variable cost (or the water value) of the plant considered as marginal. Indeed, since these technologies have limited technical constraints and no start-up costs, they will always submit a bid at their variable costs (or their water value). Consequently, if they are expected to be marginal based on the forecast day-ahead demand, the day-ahead price is expected to be equal to their variable cost.

When fossil-fuel plants are expected to be marginal, BRPs cannot anticipate correctly the day-ahead prices. Indeed, these plants will probably have to start up to supply a higher demand and then be subject to significant technical constraints which will make the price of their bids different from their variable costs. In other words, these plants would not agree to start up and produce if day–ahead prices were only equal to their variable costs. Two points can explain this:

- The impacts of the start-up costs: If a fossil-fuel plant has to start up to cover a higher demand, the day-ahead price during the hours has to enable this plant to cover its start-up costs. Otherwise, it does not want to start up.
- The impacts of the minimum up time constraints: Once a plant has been started up, it must produce for several hours before being shut down. This may require it to produce outside the peak period when nuclear or hydroelectric plants are marginal and when the day-ahead price is defined by their low variable costs. During these hours, the fossil-fuel power plant will make losses since its variable costs are higher than the expected day-ahead prices: to accept to start up, it is necessary that the day-ahead prices during peak period cover these losses.

Thus, the estimated day-ahead prices have to be higher than the simple variable cost of the fossil-fuel technology considered as marginal. However, the exact price is difficult to determine because it depends on the type of fossil-fuel plants which is marginal (coal-fired plants, CCGT plants or combustion turbines), its technical constraints, the number of hours the fossil-fuel power plant is expected to be marginal, the losses it incurs during the hours it must produce for an estimated day-ahead price lower than its variable cost, etc. Thus, for hours when the fossil-fuel technologies are expected to be marginal, different price scenarios are considered to reflect this strong uncertainty. Moreover, these price scenarios are calculated based on the number of hours during which fossil-fuel plants are expected to be marginal for the next day. For example, if this type of technology is expected to be marginal during only one hour over the next day, the day-ahead price during this hours needs to be higher than if the technology is marginal for 3 hours since costs (in particular start-up costs) can be covered over more hours in the latter case.

In order to determine these scenarios, a very simplified estimation of the required day-ahead prices that should be necessary to cover start-up costs and losses made during the hours fossil-fuel plants would be obliged to produce is computed. In particular, these calculations are made according to the number of hours the fossil-fuel plants are expected to be marginal over the next day. It should be noted that the aim of these calculations is not to estimate precisely bids made by these technologies (this will be done thanks to the UCM) but only to have an estimation of the day-ahead prices.

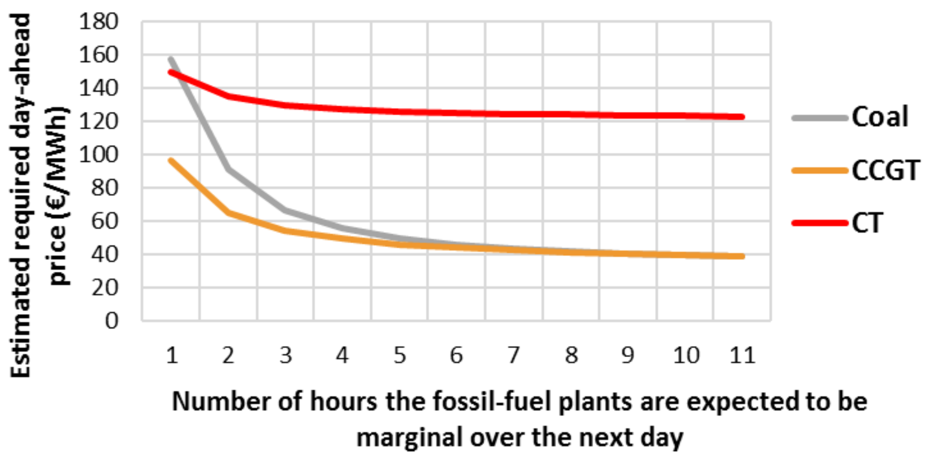

Figure 84: Simplified estimation of the required day-ahead prices for thermal plants depending on the numbers of hours they are expected to be marginal over the next day

Approximate values are shown in figure 84 for the three fossil-fuel technologies. It can be read as follows: if fossil-fuel plants are expected to be marginal during one hour for the next day, a CCGT plant will require the day-ahead price to be around 100€/MWh during this hour so that it agrees to start up and produces. If the price is lower, the plant cannot cover its costs and then does not want to produce. For a coal-fired plant, the required approximate day-ahead price is about 150€/MWh. Indeed, coal-fired plants must respect more constrained technical characteristics (in particular the minimum up time is long): starting them to produce during one hour only is then very expensive. According to these approximate calculations, coal-fired plants become competitive compared to CCGT plants when fossil-fuel technologies are expected to be marginal for more than 7 hours a day.

BRPs can therefore anticipate that if fossil-fuel plants are expected to be marginal for one hour the following day, then the day-ahead price should be close to 100€/MWh for this hour. However, this estimation is very uncertain because technical constraints have been considered in a very simplified way in this previous calculation. Moreover, the demand level to be covered by the fossil-fuel plants has not been considered. For instance, if these plants have to produce 300 MW or 3,000 MW, the estimated day-ahead price will surely be different. Then, five day-ahead price scenarios are considered to reflect this uncertainty in the modelling. The median price scenario is assumed equal to the lowest price obtained in figure 84. For instance, if fossil-fuel plants are expected to be marginal for one hour, the median price scenario for this hour will be equal to € 100/MWh. Moreover, the lowest price scenario is assumed equal to the variable cost of the marginal fossil-fuel plant. For the same example, the lowest price scenario will be the variable costs of a CCGT plant. Remaining price scenarios are built considering a same price difference between each one. Results of the estimated day-ahead price scenarios corresponding to the merit order of figure 83 are illustrated in figure 85.

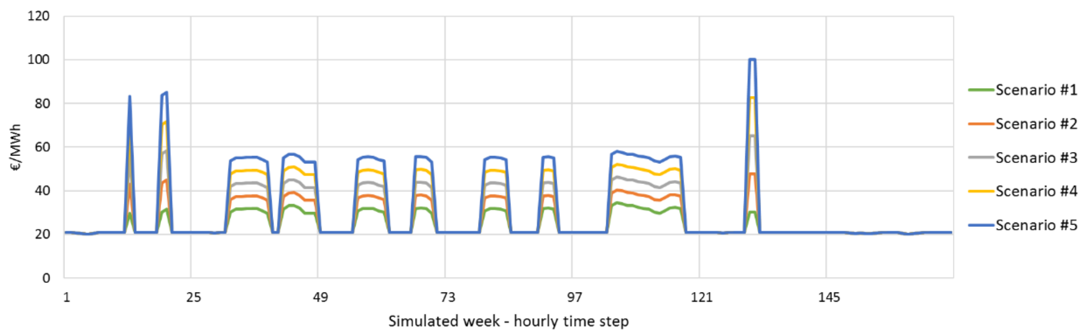

Figure 85: Expected day-ahead price scenarios for one winter week

As explained at the beginning of this appendix, in the alternative security model, BRPs consider two situations for the provision of upward RR (provision by hydroelectric plants or coal-fired/CCGT plants). It then results in two price forecasts (since different types of technologies are expected to be removed from the supply side on the day-ahead market). The final day-ahead price scenarios considered by BRPs in the alternative model is chosen arbitrarily as the average of both price forecasts.

Appendix L. Study of downward RR and of downward margins

L.1 Study of the downward RR procurement market

3.6 GW are procured in the alternative security model only. These reserves are identified to be provided exclusively by nuclear plants (see figure 86 and figure 87) whatever the simulated week. Indeed, these plants (in particular those with the lowest variable costs) are always expected to produce as base-load generation and then close to their maximum output. As a consequence, they can provide downward reserves without modifying their generation schedule and at a zero opportunity cost.

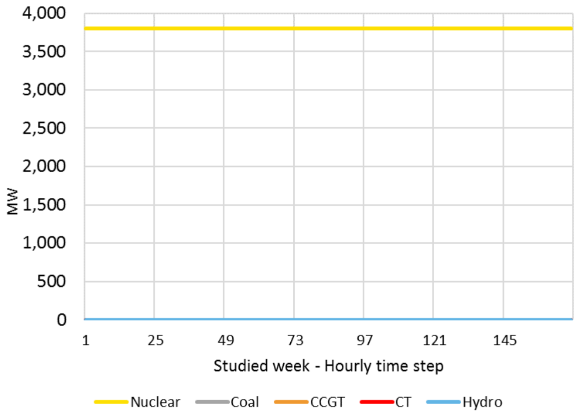

Figure 86: Technology identified to provide downward RR for one winter week

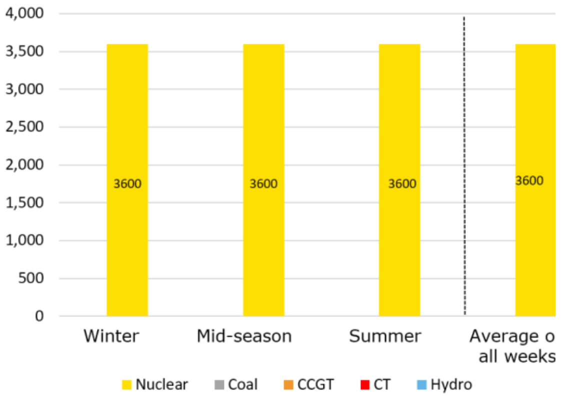

Figure 87: Average procured downward RR for each technology and each type of weeks

The resulting procurement price is then always equal to zero for the alternative security model as depicted in figure 88.

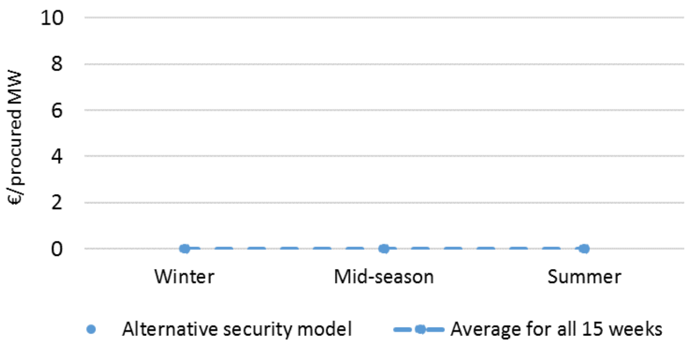

Figure 88 : Average procurement price for each type of weeks

Consequently, it should be noted that the procurement of additional downward RR in the alternative security model does not result in any change in production decisions and then does not explain production differences between both security models. Indeed, nuclear power plants can provide this reserve without modifying their production schedule. In particular, no technologies other than baseload nuclear plants are forced to produce during off-peak periods to provide the downward reserves.

L.2 Simplified study of downward margins

The available downward margin for the 2-hour maturity is depicted in figure 89 for the same winter week as previously. It is verified that the available margin is always greater than the required margin for the 2-hour maturity. No activations to ensure downward system margin are therefore necessary. It is also noted that the available downward margin follows the opposite evolution of the available upward margin: it is high during peak period and lower during off-peak periods, especially during weekend.

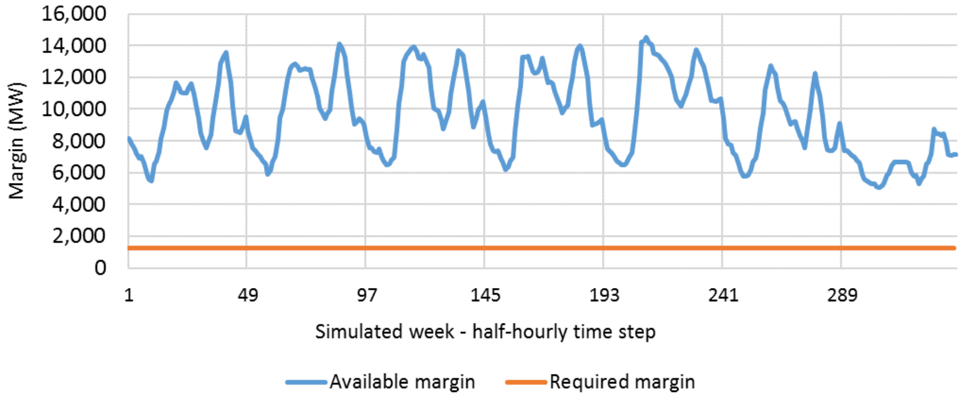

Figure 89 : Downward margins for on winter week

Figure 90 shows for each type of simulated week the minimum available downward margin with a 2-hour maturity. In all cases, these values always remain higher than the required margin: no activations are therefore necessary[182].

[182] It is observed that this volume is lower for the summer week. Indeed, fewer plants are expected to produce to cover the low demand: the possible generation decrease over 30 minutes is then limited.

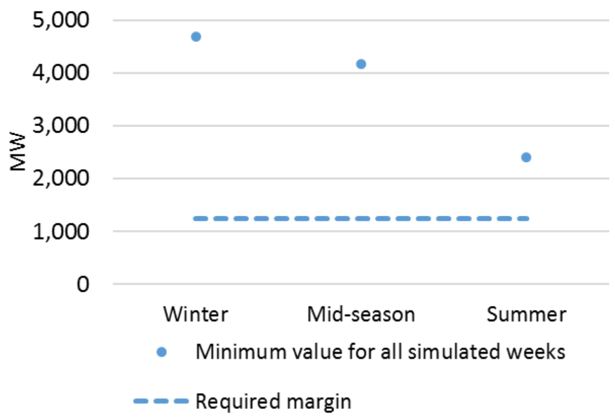

Figure 90 : Minimum downward margins for each type of weeks

Then, similarly to the alternative security model, the management of the downward margin does not result in additional costs for the French security model.

Both security models are then similar regarding the downward margin and the assurance for the TSO to have enough available capacities to deal with large positive imbalances. This is explained by the higher flexibility of French nuclear plants compared to the ones installed in other countries. These plants can provide large downward reserves and margins in both security models without modifying their production schedule. However, this conclusion could be different in the future (and costs non-zero) if positive imbalances and downward activations become more problematic, in particular due to the increase of wind and PV productions.

Appendix M. Newly identified plants to provide reserves during the rescheduling stage

During the rescheduling stage, BRPs can modify the power plants they identify to provide the reserves they have previously committed to make available for the TSO[183]. It enables BRPs to provide reserves with the cheapest plants, while respecting other technical constraints and optimizing their imbalances. Generation decisions and identification of plants which will provide reserves are jointly solved. Newly identified plants to provide reserves for both security models and each type of weeks are depicted in figure 91.

In the French security model, there is no difference for the provision of upward RR: offline combustion turbines still provide all upward RR. For the alternative security model and for the upward RR, it first appears that combustion turbines still provide a large share of these reserves. Moreover, the volumes provided by coal-fired and CCGT plants also increase by an average 76 MW compared to the volumes identified during the procurement stage. This change is mainly due to the lower uncertainty about the generation schedule of BRPs during the rescheduling stage than at the time of procurement markets. Indeed, at the time of the procurement markets, BRPs use several price scenarios to reflect their uncertainty about future situations and their potential production schedules. For each price scenario, they compute an expected production schedule based on the results on the UCM. In particular, for the lowest price scenario, coal-fired and CCGT plants may be not expected to produce. The opportunity cost to provide upward reserves in this case is then high since these plants must be started up. During the procurement stage, BRPs then prefer to provide upwards RR with hydroelectric plants whose opportunity costs are lower if the lowest price scenario occurs. However, during the rescheduling stage, these uncertainties are lower and BRPs determine themselves the generation schedule of their plants. In particular, during peak hours, they know whether their fossil-fuel plants are expected to produce or not (mainly based on the energy they sold on the day-ahead market). If these plants are expected to produce, BRPs can use them to provide upward reserves. Since their variable costs are higher than those of hydroelectric or nuclear plants, BRPs will identify these plants first

[183] However, since procurement markets already occur, the volume which has to be provided by each BRP cannot be modified. Only plants which will provide these reserves inside the same portfolio can be modified.

to provide the upwards RR (their opportunity cost is lower). However, due to their technical constraints (in particular their ramping constraints), they can provide a limited volume of reserves only and hydroelectric plants still have to provide the great majority of upward RR along with combustion turbines. Finally, for downward RR, nuclear plants are still identified to provide all reserves since they are scheduled to provide as baseload plants (cf. figure 92).

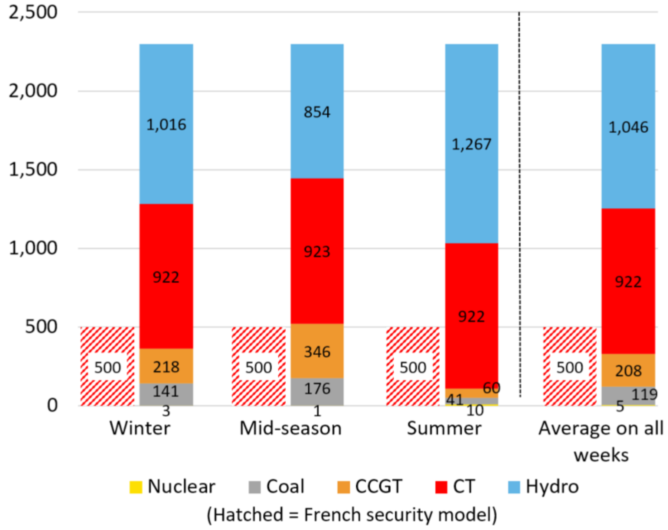

Figure 91: Average upward volume procured by each technology as identified after the rescheduling for each type of week

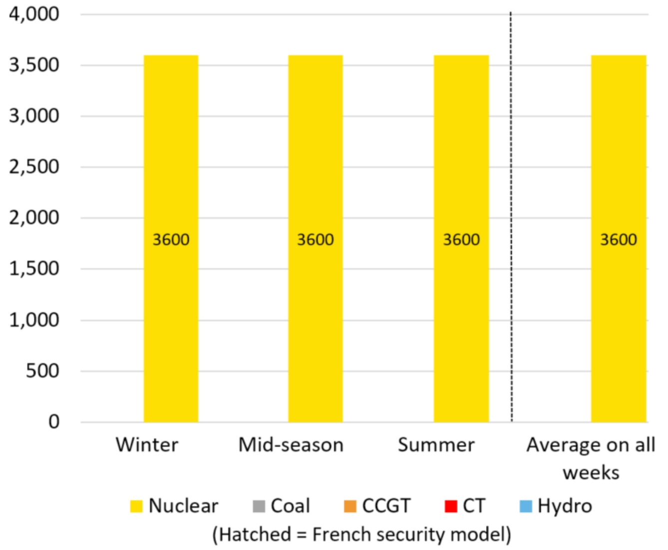

Figure 92: Average downward volume procured by each technology as identified after the rescheduling for each type of week

Appendix N. Definition of the imbalance settlement price

Two methods are considered to compute the imbalance settlement prices (ISP): one based on the average weighted prices of activations (as it is done currently in France) and one based on the marginal prices.

The solution based on the average weighted prices of activations is the one currently implemented in France (RTE, 2018). Moreover, capacities activated to ensure system margin are considered within this computation for the upward average weighted price. However, the price considered for these activations is capped at the price of the most expensive bid accepted on the balancing mechanism to solve imbalances. For instance, if the price defined by bids activated to ensure system margin is € 100/MWh and the price defined by the last bid activated upwards on the balancing mechanism to solve imbalances is € 30/MWh, then activated bids to ensure system margin are considered at this latter cost in the computation of the upward average weighted price. For a downward trend, only bids activated downwards are considered (since there are no activations to ensure downward system margin in the modelling, they do not have to be considered in the computation of the downward average weighted price).

However, it should be noted that an average weighted price to compute ISP is often considered when a pay-as-bid rule is implemented to remunerate bids activated on the balancing mechanism, as it is the case in France. Otherwise, if activated bids were remunerated based on a marginal pricing, the mechanism would not be cost-neutral for the TSO. For instance, in case of upward activations, the costs it will bear to remunerate activated bids will not be covered by ISPs. That is why a pay-as-bid rule to remunerate activated bids and a weighted average price to compute ISP are often considered together (and often considered in Europe (ENTSO-E, 2017). The other solution would be a marginal pricing to remunerate activated bids and an ISP defined on the marginal price (as in the Netherlands for instance).

However, if a pay-as-bid rule were implemented to remunerate activations on the balancing mechanism, bids would not be submitted at their marginal cost. BRPs would increase their bids above their marginal costs in order to try to capture the infra marginal rent. In particular, they would try to estimate the price of the last accepted bid on the balancing mechanism and would bid at this estimated price. In theory, with perfect information and perfect competition, marginal pricing and pay-as-bid pricing should produce the same results (Saguan, 2007). However, within the modelling, the estimation of the price of the last accepted bid is not performed to simplify the problem. Indeed, this estimation is difficult since it depends on the balancing trend of the system, on bids submitted by each plant… For the sake of simplicity, it was assumed that bids are submitted at their marginal cost in the modelling.

That is why a second formulation of ISP is defined. It considers the price of the marginal bid activated to solve imbalances to define ISP. This solution is not currently implemented in France but is better aligned with bids submitted at their marginal cost as it is assumed in this modelling[184]. Then, depending on the balancing trend, ISP are defined based on the price of the last bid activated to solve imbalances. Moreover, activations to ensure system margin are considered in a similar way as it is currently done in France. In case of a downward trend, activations to ensure system margin are not considered and the price of the least expensive bid activated downwards on the balancing mechanism is considered to define ISP.

In case of an upward trend, activated bids to ensure system margin are considered at the minimum value between the price they submit and the price of the last activated bid on the balancing mechanism. Then, in any case, the marginal price remains the same when activated bids to ensure system margin are considered and is defined by the most expensive bid activated upwards on the balancing mechanism.

In any case, the definition of these ISPs do not really matter in the modelling since these prices are only an output of the simulation. In particular, no feedbacks are considered and BRPs do not react based on previous ISPs (due to the complexity for this consideration). The definition of these prices cannot change BRPs decisions and then the comparison of social welfare between both security models.

[184] This second method can be seen as a pay-as-bid rule where all activated plants are able to predict perfectly the price of the marginal bid.

Appendix O. Final production for one mid-season week and one summer week

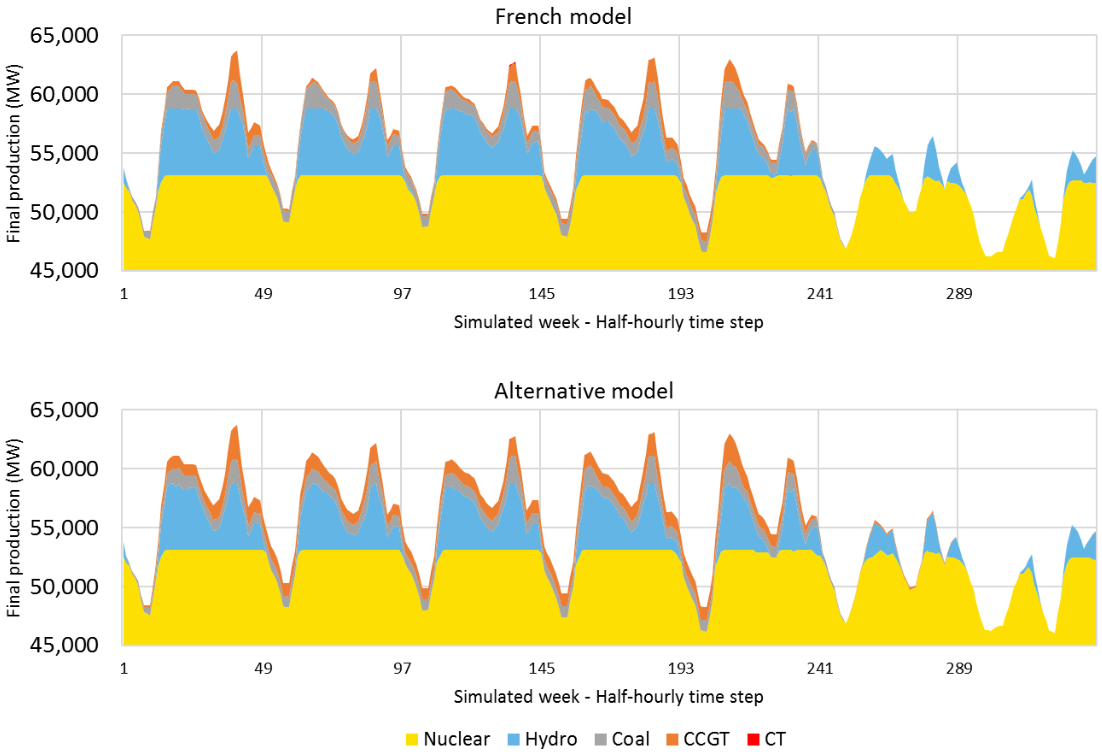

Figure 93: Final production for both security models for one mid-season week

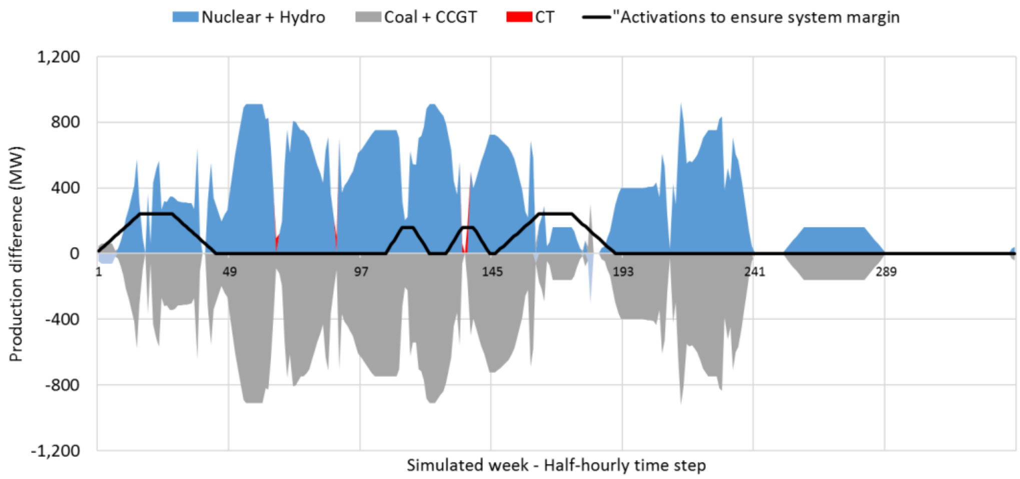

Figure 94: Production difference for one mid-season week

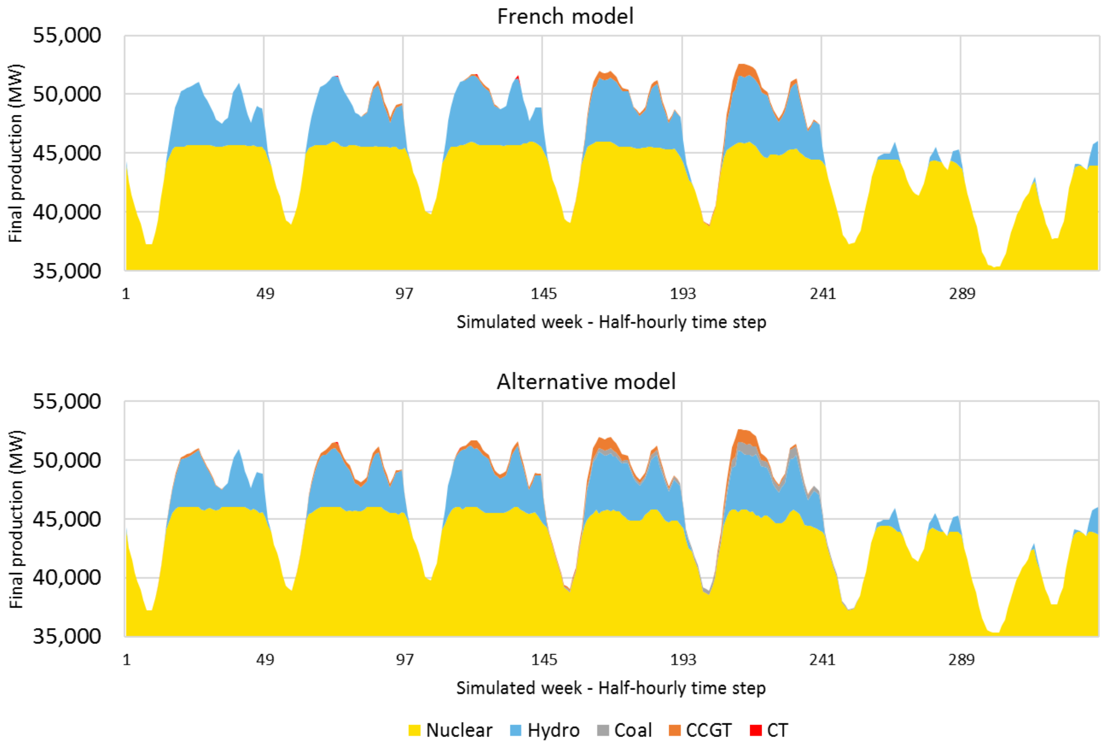

Figure 95: Final production for both security models for one summer week

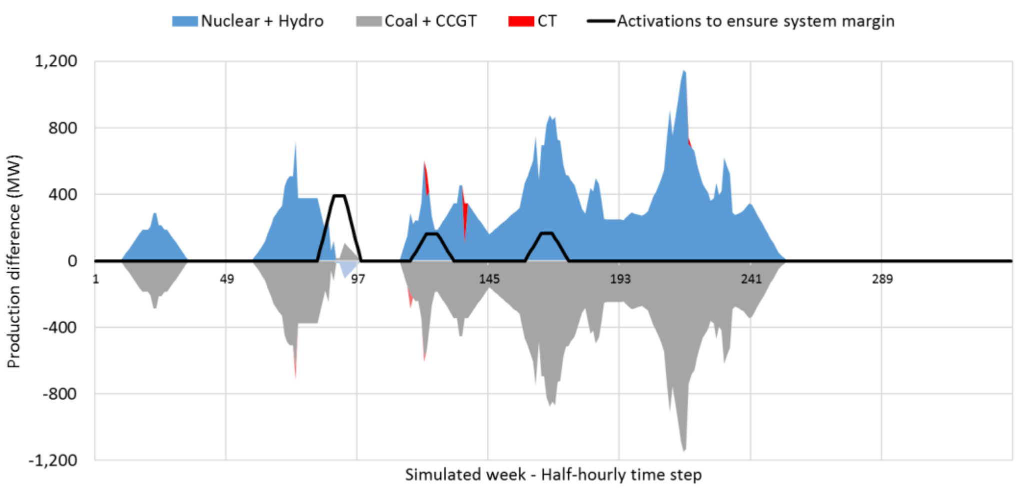

Figure 96: Production difference for one summer week

Appendix P. Evolution of the water reservoir level and of the water value for one mid-season week and one summer week

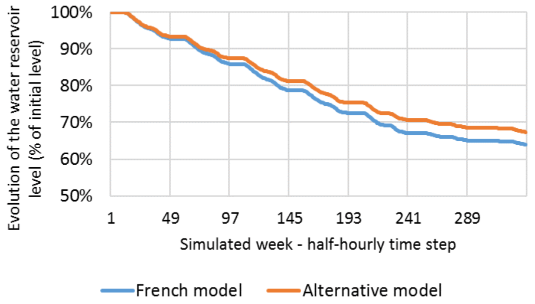

Figure 97: Evolution of the water reservoir level for one mid-season week

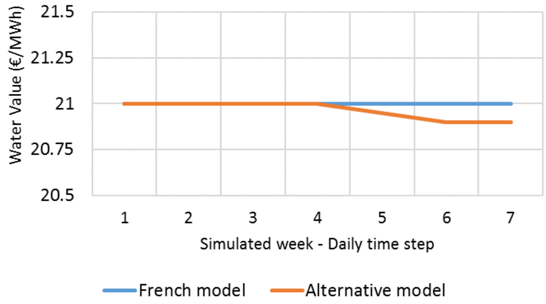

Figure 98: Evolution of the water value for one mid-season week

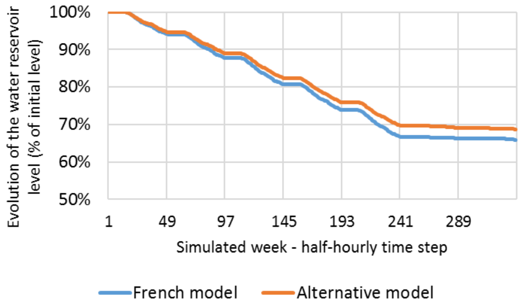

Figure 99: Evolution of the water reservoir level for one summer week

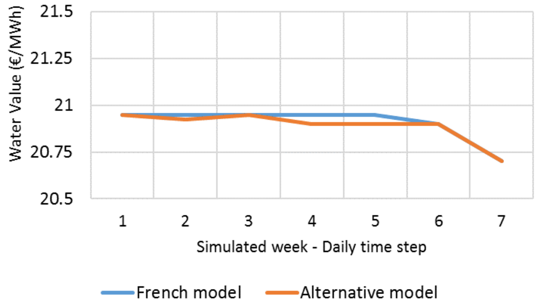

Figure 100: Evolution of the water value for one summer week

For the summer week, the water value is lower than for other types of weeks. Indeed, the water reservoir at the beginning of the simulation is considered identical for all weeks. Since the demand is low for the summer week, hydroelectric plants tend to produce instead of the most expensive nuclear plants; the water value is lower than for the winter and mid-season weeks and is lower than the variable costs of several nuclear plants, which reflects this trade-off.

Appendix Q. Additional sensitivity results

In this additional sensitivity analysis, the alternative case 1 of the table 14 (i.e. with a capacity addition when NPV=0 equal to 5.9%) is considered as the new reference case. This case is chosen since it results in the best performances for the strategic reserve mechanism regarding the cost effectiveness. This new additional sensitivity analysis enables to assess whether, by combining a higher capacity addition and another varying parameter, the strategic reserve mechanism is more adequacy-effective and more cost-effective than the capacity market. The new alternative cases are presented in the table 24 thereafter. They are simulated for the same 500 scenarios as previously. Results are also presented in this table, in which the average differences in cost effectiveness and adequacy effectiveness indicators for the 500 scenarios are depicted, as well as the numbers of scenarios in each quarter of the figure 101.

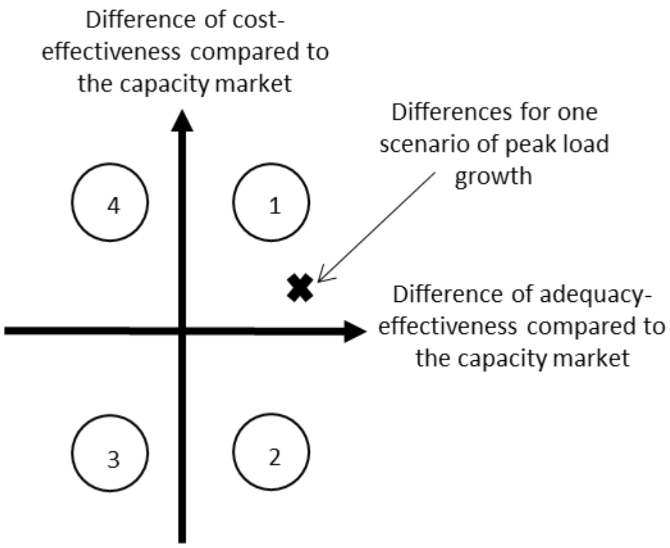

Figure 101: Graphical depiction of the differences in both indicators for each load scenario

For all alternative cases, the capacity market is still more cost-effective and more adequacy-effective than the strategic reserve mechanism, since average differences in each indicator are always positive and the greatest majority of scenarios are in quarter 1 or between the quarter 1 and 4 (i.e. same adequacy effectiveness but a higher cost effectiveness with the capacity market). Main explanations mentioned in the section 7.5 remain true for this additional sensitivity analysis. For some cases (for instance the alternative case B), the difference between the alternative and the reference cases are not in the same direction as in the section 7.5. This is mainly explained by the overcapacity phases prone to happen in the new reference case for the energy-only market: these phases impact the performances of the strategic reserve mechanism (both its adequacy effectiveness and its cost effectiveness) but does not change the way the capacity market works since this design can avoid them by decreasing the capacity price. In any case, the economic performances for these new alternative cases are always better for the capacity market.

Table 24: Results for the additional alternative cases

Case		Varying parameter	Value	Mean difference in		Number of scenarios in/on[185]:			
				Adequacy effectiveness (% of peak load/year)	**Cost effectiveness** ($/MW of peak load/year)	Quarter 1	Quarter 2	The line between quarter 1 and 4	The line between quarter 2 and 3
Ref		-	-	0.013	866	218	0	282	0
Different behaviour of market players	A	NPV to reach the maximum capacity addition	$400,000/MW	0.045	966	384	0	116	0
	B		$800,000/MW	0.005	878	124	0	376	0
	C	Years used to compute the expected revenues for investment and shutdown decisions	y to y+4	0.010	703	187	11	295	7
Different market conditions and market design	D	Revenues earned on the energy market	Revenues are 20,000 $/MW higher	0.000	660	13	0	487	0
	E		Revenues are 40,000 $/MW higher	0.000	863	2	0	493	5
	F	Maximum amount of strategic reserves	30% of the previous year installed capacity	0.000	880	1	0	499	0
Different costs and technical parameters	G	O&M costs	$15,000/MW during the first ten years	0.025	780	306	0	194	0
	H		$20,000/MW during the first ten years	0.048	709	414	0	86	0
	I	Lead time	2 years	0.013	888	223	0	277	0
	J		3 years	0.016	893	223	0	277	0
Different load	K	Peak load growth	4%	0.008	1,286	156	0	344	0
	L		0.5%	0.557	15,203	500	0	0	0

[185] For each case, there is no scenario in the other quarters.

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Résumé

Suite aux réformes des marchés électriques, la question du market design, c'est-à-dire l'étude des nouveaux marchés destinés à remplacer l'ancien monopole, est devenue centrale dans la littérature économique. Toutefois, les caractéristiques techniques de l'électricité rendent cette tâche complexe et l'intervention des pouvoirs publics est souvent nécessaire pour établir les règles du jeu efficaces que les acteurs de marché devront suivre. Cela explique pourquoi le market design demeure un sujet d'actualité. Cette thèse contribue aux discussions actuelles en étudiant plusieurs architectures de marché à mettre en place afin d'assurer la fiabilité du système électrique de la façon la plus efficace.

La fiabilité est d'abord étudiée sous sa dimension de court terme, appelée sûreté. Pour garantir un équilibre en temps réel, l'opérateur du système doit s'assurer de disposer d'un niveau suffisant de réserves: c'est l'objectif du modèle de sûreté. Dans cette thèse, les impacts économiques induits par un changement de modèle de sureté pour le système électrique français sont évalués. Une modélisation de type Agent-Based est développée pour simuler les décisions des acteurs sur plusieurs marchés de court terme. Les résultats montrent que le modèle de sureté français actuel conduit à des coûts inférieurs à ceux du modèle alternatif mis en œuvre dans d'autres pays européens. Le maintien du modèle actuel en France apparait donc justifié.

La dimension long terme de la fiabilité, à savoir l'adéquation, est ensuite étudiée. Les performances économiques d'un marché de capacité et d'un mécanisme de réserve stratégique, deux solutions conçues pour résoudre le problème d'adéquation, sont comparées. Afin de considérer la nature cyclique des investissements, ces mécanismes sont étudiés d'un point de vue dynamique par l'intermédiaire d'une modélisation de type System Dynamics. Celle-ci simule les décisions d'investissements et de fermetures prises par les acteurs de marché, en considérant leurs comportements imparfaits. Les principaux résultats montrent que le marché de capacité résout la question de l'adéquation à un coût moindre.

Mots Clés

Architecture des marchés électriques ; Adéquation de capacité ; Sûreté du système électrique ; Simulation

Abstract

Following power market reforms, market design, i.e. the study of new markets to replace efficiently the previous monopoly, becomes central in the economic literature. However, due to several technical characteristics of electricity, this task is complex. A third party is then required to help design these markets in an efficient way and to set the rules under which private decentralized market players will interact. This complexity explains why market design remains a work in progress. This thesis contributes to the current discussions by giving insights on the most efficient market designs to implement to ensure the reliability of power systems.

A first focus is made on the short-term dimension of reliability, i.e. the security of power systems. To maintain a balanced system, the system operator has to ensure the availability of a sufficient level of reserves in real time: this is the aim of the security model. In this thesis, a quantitative assessment of the economic impacts that a transition to a different security model would have for the French power system is carried out. An agent-based modelling is developed to simulate the decisions of profit-maximizing players on several short-term markets. Simulations show that the current French security model results in lower costs than the alternative one implemented in several European countries, and should therefore be maintained for the French power system.

A second focus is made on the long-term dimension of reliability, i.e. the adequacy. The economic performances of a capacity market and a strategic reserve mechanism, two mechanisms designed to solve the adequacy issue, are compared. In order to capture the cyclical nature of investments, these mechanisms are studied from a dynamic point of view. To this end, a long-term model is developed based on a System Dynamics approach. It simulates the investment and shutdown decisions made by market players considering their imperfect behaviours. Main results show that the capacity market solves the adequacy issue at a lower cost than the strategic reserve mechanism.

Keywords

Electricity market design; Capacity adequacy; Short-term security; Simulation modelling